Productive and low-emissions business

Commercial-scale solar in New Zealand

An analysis of the financial performance of on-site generation for businesses

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Contents

Foreword

Productive and low emissions business is one of EECA's key strategic focus areas, and the opportunity for businesses to generate lower cost electricity on-site from solar is something that is becoming increasingly popular, and many are exploring.

On-site solar generation takes advantage of the economy of scale provided by larger roof areas often available on commercial buildings, and the fact that businesses generally use more electricity during the day when the sun is shining.

This report is intended to give those businesses contemplating this investment a guide to what financial returns may be possible, and also to act as a guide to the type of analysis which they should conduct or commission, in order to make an informed decision.

More generally, this report also contributes to our understanding of the costs and benefits of commercial-scale solar to the electricity system. Solar is unique among generation technologies in being scalable from residential to utility, and with costs constantly falling the key question for the sector is where to best locate generation to deliver the best economic outcome.

EECA is pleased to have worked alongside Dr Allan Miller and the team at ANSA to deliver this research, and I trust that it will be a valuable resource for businesses considering their emissions reductions goals.

Andrew Caseley
Chief Executive Officer

EECA TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

Executive summary

This report examines the financial performance of commercial-scale solar in New Zealand by modelling systems for 144 business sites across eight centres. These sites include a range of food and beverage businesses from primary production, through processing and distribution to retail, as well as infrastructure, manufacturing, general retail, offices, and education.

Commercial-scale solar is defined in this report as systems sized between 10 kW and 1 MW. These systems would typically be located on the roof of a business, and can provide businesses with lower electricity costs. System size should be optimised for each site, and the model used here selected this by maximising the internal rate of return (IRR) for the business.

The 144 sites analysed used real electricity consumption data supplied by eleven New Zealand businesses. These have been grouped into fifteen different load types, with the distribution by load type and location shown in Table 9. This case study approach is intended to represent a range of different businesses, allowing general conclusions about the costs and benefits of commercial-scale solar.

We found that internal rates of return vary significantly: from a high of 8.6% for a manufacturing site in Auckland, to a low of 0.4% for a big box retail site in Dunedin. This is partly due to sunshine hours being more favourable in Auckland than Dunedin. However, the Auckland site also has a much higher load and has a much larger solar array that maximises the IRR: 1000 kW versus 30 kW. Larger systems have lower per unit capacity costs ($/W) and, all other factors being equal (such as the proportion of electricity generated being used on site), larger systems will generate higher IRRs. Average IRRs by load type and location are shown in Table 10.

The sensitivity of the IRR to the assumed capital cost was investigated, along with the sensitivity to retail, distribution, and wholescale price inflation, the choice of wholesale price year on which those prices were based, and the tilt and bearing of the panels. Capital cost had the most impact, with IRR reducing about 20% when capital costs were increased 20%, and IRR increasing about 35% when capital costs were reduced 20%. Businesses may be able to access the lowest costs tested in this report, and with ongoing solar cost reductions, this will continue to make solar more attractive to commercial enterprises.

A number of potential underlying drivers of IRR relating to the nature of the site electricity load were investigated, including daytime to night-time load ratio and summer to winter consumption. We found no significant correlation between these metrics and the IRR, suggesting that there is no shortcut to determining a 'real' load type that is ideally matched to solar. (Daytime load will, of course, always be preferable.)

Further analysis revealed network cost savings strongly determined IRR. This cost saving results from a coincidence of load, generation, and network pricing that strongly rewards demand reduction, often at peak times. IRRs above 5% were only achieved with good network cost savings, while the highest IRRs – above 8% – combined high network cost savings with high energy cost savings.

To identify these factors requires half-hourly analysis for a full year, and detailed modelling of network pricing structures. **A key recommendation for businesses considering investing in solar is to carry out this type of analysis to accurately forecast financial returns.**

The importance of network cost savings for a business investing in solar is also a key finding for electricity distributors. It means that, in the cases identified, existing network pricing structures may send a signal for businesses to invest in distributed solar generation, and so distributors should consider whether this leads to a commensurate reduction in the cost of providing a network service.

A guide to this report

This report is intended to have multiple audiences. For businesses considering investing in solar, this report is intended to act as a guide to the returns which may be possible for their business/load type. It is also intended to act as a guide to the type of analysis which they should conduct or commission before investing. Sections 1 and 2, for an introduction to key concepts, and the results of Section 4 will be the most relevant.

For those modelling solar installations, the methodology and data sources specified in Section 3 and in the Appendices are intended to detail how this work was conducted, and act as a starting point for further research.

For electricity distributors, and others with a technical interest in distributed generation, it is intended that the whole report will be a useful contribution to the knowledge base.

1 Introduction

This study examines the financial performance of solar photovoltaic (PV) generation and consumption at a commercial scale in New Zealand, considered here to be any solar capacity between 10 kWp and 1 MWp.[1]

Eleven different companies took part in this study, which utilises a case study approach. These were chosen as being representative of a range of businesses that might benefit from solar, based on expected load profiles. Half-hourly consumption data provided by the companies was used as input to a model which also included solar array generation data, data on system efficiencies, system capital costs, and electricity pricing for both consumption (import) and export. The model was then used to assess the solar array size that gave the maximum internal rate of return (IRR).

The business types included are listed in Table 1. Note that from the eleven businesses we have listed fifteen categories, given that the consumption data applied to a specific site. In total 144 sites across all these businesses were assessed, across eight New Zealand cities. The cities considered were Auckland, Hamilton, Tauranga, Napier, Wellington, Nelson/Tasman, Christchurch, and Dunedin.

This report presents the study and its results. It begins by outlining commercial-scale solar and how it works with a business's electricity consumption to provide cost savings. The study methodology is then outlined, followed by results from the case studies. These results are then discussed, followed by conclusions. The report contains a number of appendices with supplementary information.

All currencies used in the report are in New Zealand dollars and relate to 2021.

Table 1: Business types considered.

Load type	Description	Abbreviation
Big box retail	Large floor area retail outlet, single brand	BBR
Retail	Retail mall encompassing many retailers	RTL
Grocery retail	Food and grocery supermarket with high refrigeration load	FRWRL
Food market	Wholesale food market floor	MKT
Cool store	Horticulture produce cool store and packhouse	CLSTR
Greenhouse	Horticulture greenhouse	GRNHS
Corporate office	Large office space, incorporating base build and/or tenancy loads	CO
Retail warehousing	Warehousing dedicated to a single big box retail brand	RW
Warehousing	Warehousing by a logistics company, including refrigeration	WHS
Production	Food and beverage production	PROD
Manufacturing	Engineering and product manufacturing	MANU
Education	Tertiary education campus	EDU
Waste water treatment	Waste water treatment	WWT
Water supply	Water supply including water pumping	WS
Dairy Farm	Dairy farm (does not include dairy factory)	DAIRY

[1] Installed solar capacity figures use the units kWp or MWp to denote that this refers to peak capacity.

2 Commercial-scale solar

2.1 Commercial solar energy system concepts

In this study a commercial-scale solar energy system is defined as a solar generation system comprising an array of solar modules connecting to an inverter. This is then connected to the electricity network within a business, before the electricity meter used for billing, as illustrated in Figure 1. Thus, solar generation will reduce metered electricity consumption from the grid, and thereby reduce purchases of energy from the business's electricity retailer.

It may also result in the export of energy from the business to the electricity network. In this case, as well as reduce energy purchases from the retailer, excess solar energy is sold, providing a revenue stream. Reduction in electricity load, and therefore consumption, and in some cases export, is illustrated in Figure 2.

Commercial solar may also offset electricity purchase costs by reducing the charges applied by the electricity distributor, if these are passed on directly by the electricity retailer – this study assumes that they are. This can occur by reducing the kWh charges and peak demand kVA / kW charges from the electricity distributor. Distributor charges are discussed in more detail in Section 3.6.

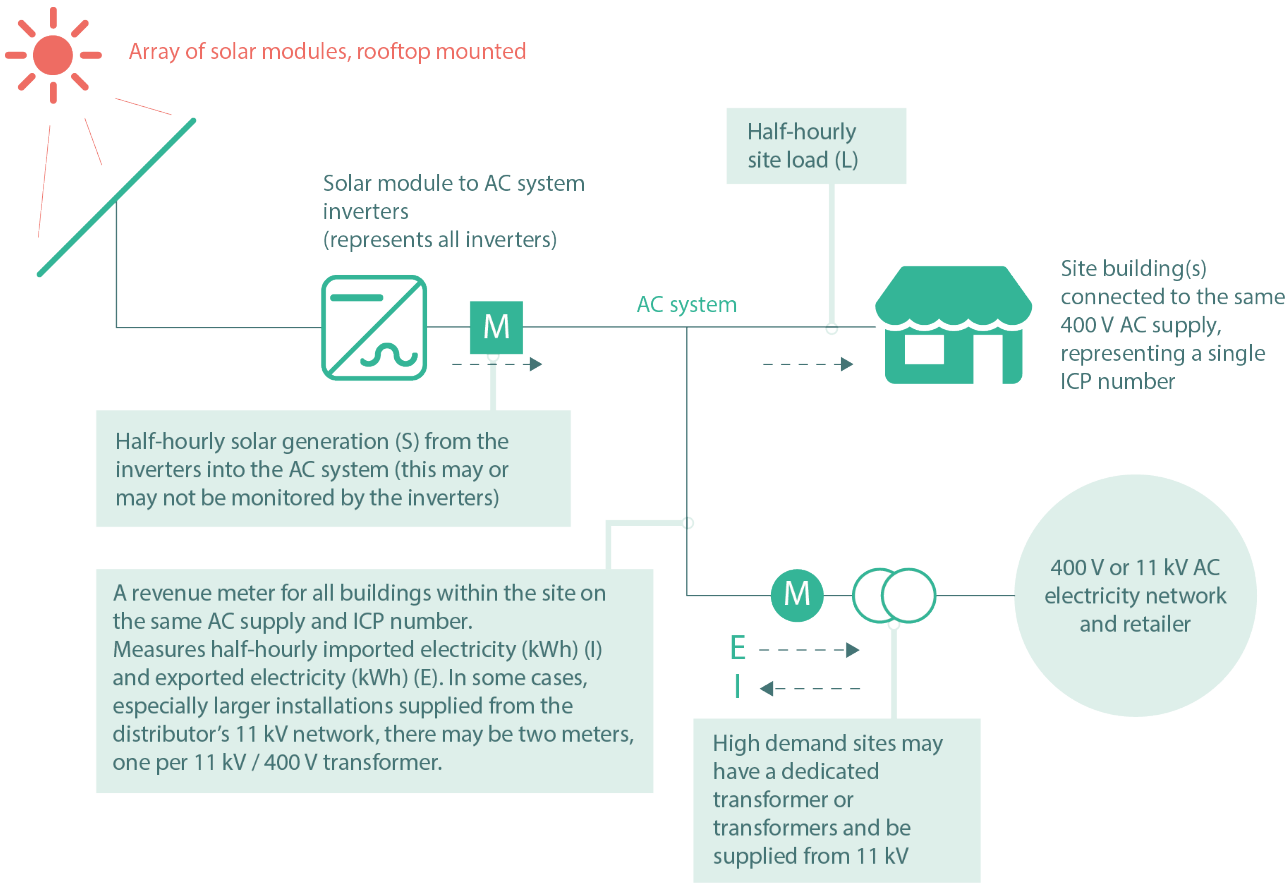
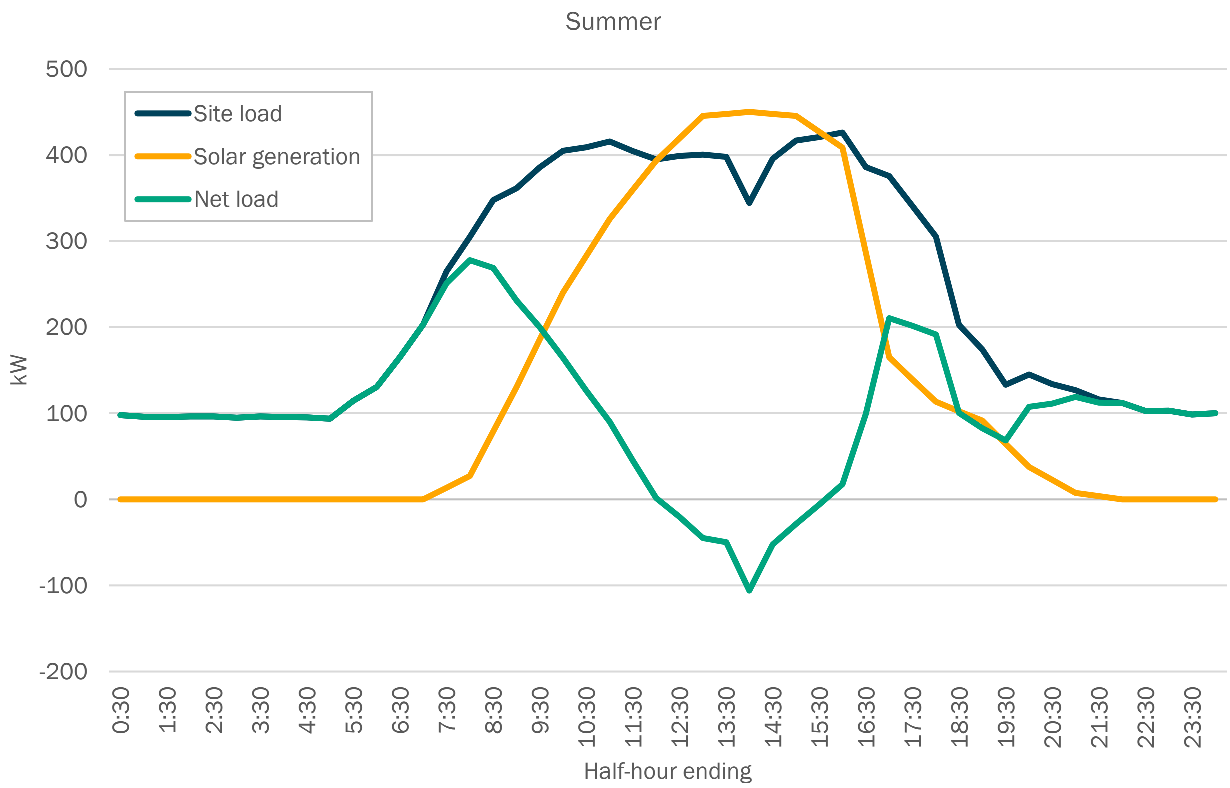


Figure 1: Commercial-scale solar connection within a business's electricity supply.



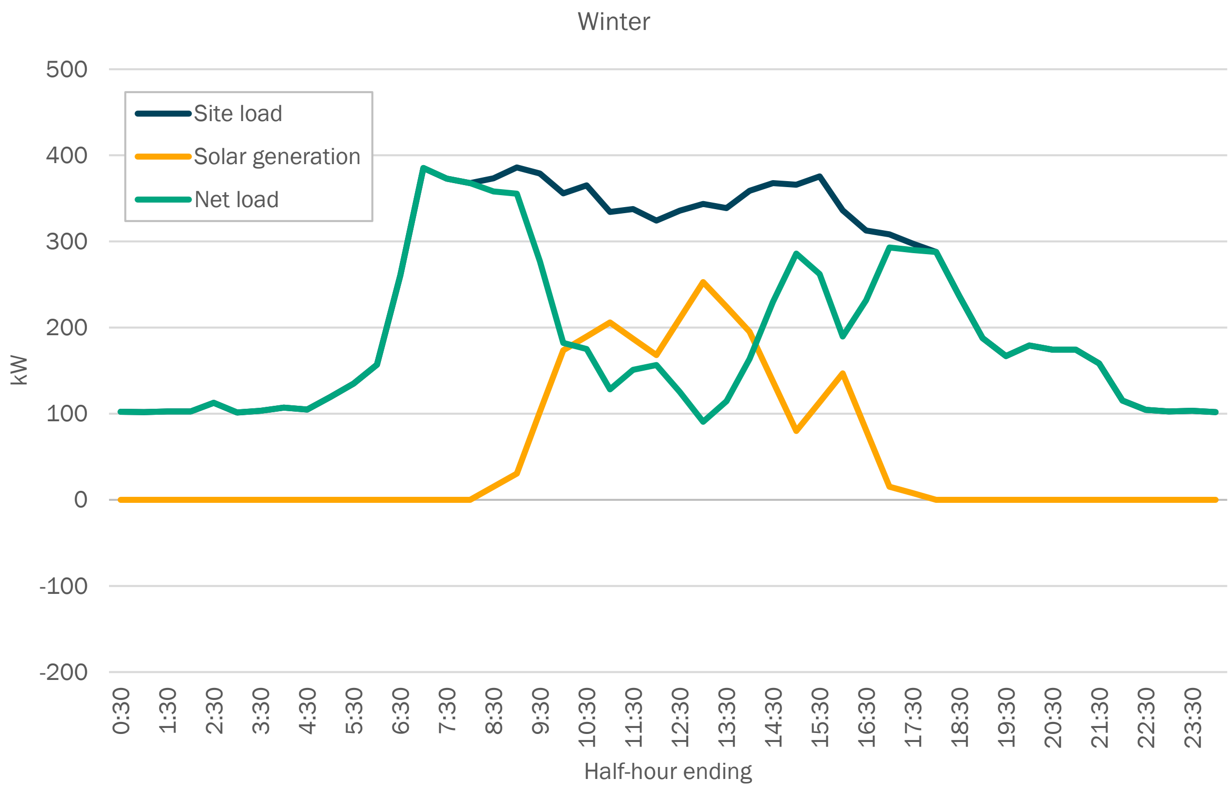


Figure 2: Commercial-scale solar operation (for a corporate office with a 500 kWp solar array in Auckland) over a day in summer (top) and a day in winter (bottom). In this example there is export to the grid in the middle of the day in summer.

A solar array is usually mounted on the roof of the building occupied by the business, but may also be mounted on adjacent land or buildings, provided it can be connected, via an inverter, to the electricity network within a business. If the solar energy system is connected to the grid as a separate ICP and revenue meter, it will not provide the energy purchase offsetting benefits shown in Figure 2. In this case it is classified as a utility-scale solar energy system, which is out of scope of this study. However, in the future peer-to-peer trading (P2P) might allow the retailing of energy from the solar site to a customer not necessarily at the site, and thereby provide similar benefits to those discussed in this report. This is an emerging option only, and not considered in this report.

The commercial business's roof orientation and slope usually determine the orientation and tilt of the solar array. This analysis assumes a north facing roof with a slope of 15 degrees – this slope was used to match the slope on many commercial businesses, some of which may even have flat roofs. Sensitivities to panel orientation and tilt are also investigated to understand how these might affect solar performance. However, roof structure and material, actual orientation, topographical shading and shading from surrounding buildings, wind loading, and seismic assessment are not included. These have the potential to increase the cost of an installation and/or reduce solar generation.

3 Methodology and data sources

3.1 Overview of model

This study utilises a techno-economic model of a solar PV system to assess the financial performance for each of the 144 sites studied. A 25-year discounted cash flow analysis is performed to calculate the internal rate of return (IRR), which is maximised by finding the optimum system size[2]. The net present value (NPV) is also calculated, assuming a discount rate of 7%.

The analysis does not consider available area for the solar array, which may constrain the solar capacity. To understand whether a solar array of capacity lower than that which maximises IRR could deliver a similar IRR, results show IRR versus array size. This is useful where available area, or building structure, may constrain solar array size.

The discounted cash flow considers the capital cost of the solar array and associated components (inverter, wiring, installation, etc). This cost is discussed in more detail in Section 3.3, with sensitivity of IRR to capital costs investigated in the results. The discounted cash flow also considers the annual energy cost savings and spot energy sales as income. Export cost (a retailer margin on exported energy) is also considered. Retail electricity prices used in determining energy cost savings are discussed in Section 3.5, with wholesale spot prices used to determine spot energy sales discussed in Section 3.4. Annual network cost savings are also considered as income. Determination of network cost savings by electricity distributors is discussed in Section 3.6. Tax is also considered as a cost, reduced by the annual depreciation of the capital investment in the solar system. Annual operation and maintenance costs are also considered. Energy generation from the solar energy system is discussed in Section 3.7. Section 3.10 provides more detail on the IRR calculation and various inputs.

Determining annual energy cost savings, spot energy sales, and network cost savings required a half-hourly model. This allowed matching of solar generation at each half-hour with consumption data from the site in question. Moreover, it allowed determination of the net business load after reduction by solar, as illustrated in Figure 2. Knowing the net load at each half-hour allowed retail energy purchase cost savings to be calculated by multiplying the load reduction by retail electricity pricing at that time (this calculation excludes load reduction that becomes export). Spot energy sales were calculated by multiplying the exported energy amount (if any) by the half-hourly spot price at the location of the business. The spot price was reduced by a small retailer margin. Network cost savings were established by considering the reduction in energy (kWh), anytime peak demand, and coincident peak demand, multiplied by the appropriate network price – discussed in Section 3.6.

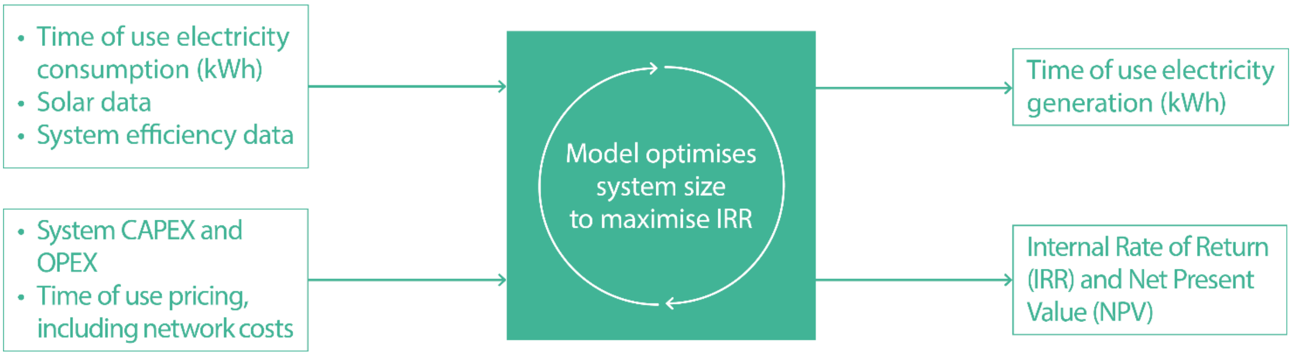


Figure 3: Schematic showing key model inputs (left) and outputs (right). Technical inputs and outputs are at top while financial inputs and outputs are at bottom.

[2] On a range of solar capacity from 10 kW to the lesser of the rounded peak load or 1 MW.

The use of IRR, with solar array capacity selected to maximise IRR, allows comparison with the business's preferred NPV discount rate (cost of capital). Since IRR is equal to the discount rate when NPV is zero, any IRR above the preferred discount rate will mean the solar system, sized according to these results, is financially viable.

3.2 Approximations implicit in the methodology and study

There are a number of approximations made in this analysis which must be considered when assessing solar viability. These are summarised below:

1. The model is forward looking, and by necessity must assume time-of-use-consumption by the business well into the future. For this purpose, the business's 2019 calendar year load profile is used as the assumed future load. It is unlikely that a business will have the same load profiles for the next 25 years, and thus, this will lead to an approximate result. Assessment using an historic load profile such as this also assumes demand is non-deferrable from one time to another, allowing a business to, for example, shift demand to maximise self-consumption.

2. The model also assumes wholesale spot prices and retail prices well into the future, with adjustments made by inflation rates. While sensitivities of IRR to inflation rates is assessed, it is impossible to predict exactly what wholesale spot prices and retail prices will be in the future.

3. Distribution prices and their structure are assumed to remain constant in the future, adjusted only by distribution price inflation. The structure of distribution prices refers to the allocation of distributor charges between energy (kWh) and demand (kW), how they recover fixed costs of their core network, apply costs associated specifically with the business's connection, and how they pass on Transpower's transmission charges. This structure therefore includes how and when kW demand is assessed, and indeed whether kW and/or kVA demand is assessed.[3] The analysis has replicated the prices and structure of the distributors supplying businesses in the up to eight areas assessed, discussed further in Section 3.6. Importantly, the allocation of distributor charges between fixed, energy, and demand charges may change in the future, and the time periods in which maximum demand is assessed may change. This is particularly relevant in the context of: (1) the Electricity Authority's desire for distribution prices to be cost reflective, reflecting both the fixed cost nature of distribution networks and that networks are sized to meet peak demand; and (2) the changing transmission pricing methodology, which may lead to changes in how distributors pass on transmission changes. These changes may significantly affect the financial benefits of distributed generation in the future. Section 5 discusses network charges in more detail.

4. It is assumed that the business can outlay the capital cost on the solar system size given, and that the business has sufficient roof or ground area and structural weight bearing capacity for the solar array.

[3] kVA demand is apparent demand from the business, which includes active power demand (kW) and reactive power demand (kVAr). Reactive power results from an alternating current (AC) power supply and reactive elements within the business's power supply, such as induction motors. Reactive elements alternately consume from, and return to, the electricity network the energy required to build up and break down magnetic or electric fields; in the case of an induction motor, this specifically involves magnetic fields within its stator windings. While this cyclical consuming and returning of energy theoretically results in no net transfer of energy from the electricity distribution network, it does increase the size of the supply required, and in practice causes some additional electrical losses. More modern electrical loads, such as LED lights, computers, or almost anything with a power electronic power supply that stores energy within capacitors, also builds and reverses electric charges cyclically.

Although roof area and structural capacity were not applied as constraints in determining the solar array capacity that maximises IRR, area and weight of modules is discussed briefly in Section 3.9.

5. The cost of planning consent required for commercial rooftop installations, which may require wind loading and structural loading assessments is assumed to be included in the capital cost estimate used in the analysis. The cost of electrical installation, including wiring, inverter installation, certification of work carried out, and ensuring compliance with relevant standards is also assumed to be included in the capital cost estimate used in the analysis.[4]

6. Other aspects of distribution charges are not considered, including loss factors (it is assumed that the solar array will not lead to changes in loss factors applied by the distributor); power factor improvement (while solar inverters can have the ability to modify power factor, it is assumed that this is not implemented); and spot price location factors (it is assumed that the solar system on its own is not large enough to affect location factors).

Finally, while the results in this analysis show, in some cases, cost savings available by avoiding distribution network costs, primarily through peak demand reduction, it should be noted that there are other ways to reduce peak demand which would have equivalent benefit.

3.3 Solar capital costs

An international review was undertaken in preparing the capital costs used in this analysis. Since the analysis is for a system purchased in 2021, forecasts of capital costs were not required beyond 2021. However, some projections were required to relate PV system capital costs to 2021 (the first year of this analysis) and adjustments to New Zealand currency were required. A snapshot of capital costs in 2021 was therefore prepared, which also gives the change in per unit capital cost as an array size increases. In all cases crystalline silicon solar technology is assumed, as this is the major type of solar technology manufactured and installed at present.

Figure 4 shows the per unit capital costs used, and how per unit capital cost varies according to system size, alongside the costs from the various studies considered. Also shown are the upper and lower capital costs the study used to investigate the sensitivity to capital cost. These are ±20% of the central case costs. For ease of reference, the specific values for 10, 100, 500 and 1000 kWp capacities are also given in Table 2.

Given the continuing reduction in solar costs, a 20% cost reduction may be reflective of the reduction in cost over the next 5 years, or alternatively may reflect low cost projects today. Such projects may include installations on new buildings where installation costs can be minimized.

Appendix One gives an analysis of each international study used to derive the capital costs summarised in Figure 4. As discussed in Appendix One, and summarised in Figure 4, the solar costs used in the study are broadly consistent with:

- IRENA Australia findings for systems above 500 kWp; and
- Lawrence Berkeley National Laboratories findings for US systems and Lazard findings at 100 kWp.

The specific values used for 10, 100, 500 and 1000 kW capacities are also listed in Table 2.

[4] Worksafe and Standards New Zealand should be consulted on the relevant standards that apply to rooftop solar installations.

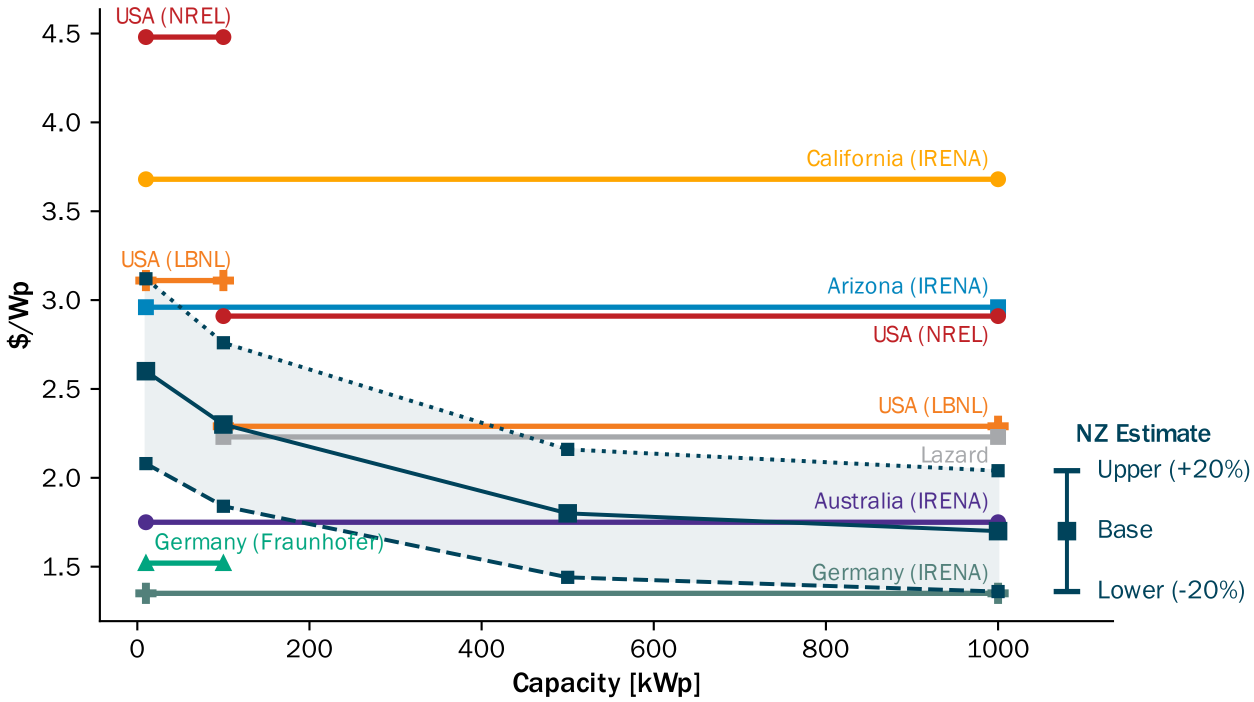


Figure 4: Per unit capital cost (NZD) at 2021 versus system size for commercial rooftop solar installations.

Table 2: Per unit capital cost (NZD) at 2021 for 10, 100, 500 and 1000 kWp system capacities.

Size (kWp)	Cost (NZ $/Wp)		
	Lower	Base	Upper
10	2.08	2.6	3.12
100	1.84	2.3	2.76
500	1.44	1.8	2.16
1000	1.36	1.7	2.04

3.4 Wholesale spot prices

Wholesale nodal spot prices, as derived in the New Zealand electricity market, were required to determine income from solar exported. Average spot prices from 2014 to 2019 were used for this purpose.[5] The sensitivity of IRR to the use of the 2016 low wholesale price year and the 2019 high wholesale price year was also investigated. Statistics of the wholesale prices used are given in Table 3, with the grid exit points (GXPs) used for each centre listed in Table 4. The prices used in the model for 2021 were applied without inflation adjustment from these previous years.

[5] Each half-hour from 2014, 2015, 2016, 2017, 2018 and 2019 were averaged to a half-hour price for an average 2014-2019 year, giving 17,520 half-hourly average prices. Days in each year were aligned to ensure alignment of day-type (weekday vs non weekday).

Table 3: Statistics of wholesale prices used in the study. Top: 2014-2019 average, middle: 2016, bottom: 2019.

Centre	2014-2019 Average ($/MWh)						
	Mean	Standard deviation	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Auckland	88	35	22	69	82	100	1698
Hamilton	86	34	21	68	81	98	1635
Tauranga	85	33	21	67	79	96	1589
Napier	84	33	21	66	78	95	1530
Wellington	83	31	22	66	77	93	1529
Nelson	87	31	24	70	82	98	1603
Christchurch	84	30	23	67	79	94	1557
Dunedin	78	26	22	64	74	87	1394

Centre	2016 ($/MWh)						
	Mean	Standard deviation	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Auckland	61	83	0	48	59	70	5462
Hamilton	60	81	0	47	58	69	5338
Tauranga	58	79	0	46	57	67	5164
Napier	58	85	0	45	56	67	5025
Wellington	55	74	0	44	53	64	4757
Nelson	56	48	0	45	55	67	4892
Christchurch	54	45	0	44	53	64	4601
Dunedin	49	40	0	40	48	59	4012

Centre	2019 ($/MWh)						
	Mean	Standard deviation	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Auckland	126	66	0	90	118	152	1082
Hamilton	124	65	0	89	116	149	1048
Tauranga	122	63	0	87	114	146	1017
Napier	120	63	0	86	113	145	1013
Wellington	115	60	0	83	108	139	1008
Nelson	123	65	0	87	116	149	1071
Christchurch	117	61	0	84	111	142	1030
Dunedin	109	56	0	78	103	132	943

Table 4: Grid exit points (GXPs) used for wholesale prices.

Centre	GXP
Auckland	OTA2201
Hamilton	HAM2201
Tauranga	TGA0331
Napier	RDF2201
Wellington	HAY2201
Nelson	STK2201
Christchurch	ISL2201
Dunedin	HWB2201

3.5 Retail pricing

Retail energy prices were required to calculate the cost saving through the reduction in retail purchases as a result of on-site generation. For reasons of commercial sensitivity, these were not requested from the businesses participating in this study, and so a representative set of retail prices was developed.

This representative set was based on 2014-2019 average wholesale spot prices for each location. A multiplier was then applied progressively in winter months to account for increased price risk in winter (such as might occur in a dry year when hydro inflows reduce). This was 115%, 140%, 130%, 120%, and 115% in April, May, June, July and August respectively. A multiplier of less than one was applied in traditionally high inflow months and summer lower demand months to account for lower price risk in these months.

Within each month the 2014-2019 average spot prices where categorised by weekdays and non-weekdays and further categorised and averaged into six four-hour time blocks. Thus, retail prices formed a table as shown in Table 5 for Wellington, with retail prices for all centres listed in Appendix Two.

Observations of known retail prices for larger commercial customers validates the use of average wholesale prices and scaling of winter month prices. However, this may not be as valid for lower consumption customers or customers with low load factors.

Table 5: Format of retail prices.

Wellington - Calculated from 2014-2019 spot price average (HAY2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.30	6.77	8.58	9.40	8.55	7.81	6.24	6.25	7.00	7.00	7.65	7.05
February	6.91	8.09	10.56	10.90	9.69	8.58	6.21	6.19	7.67	7.25	7.60	7.37
March	7.57	8.97	10.78	10.93	9.98	9.02	7.08	7.15	8.72	8.17	8.34	8.07
April	6.91	7.61	9.89	9.49	10.64	8.92	6.63	6.26	8.26	7.60	8.68	7.60
May	7.38	7.95	11.22	9.73	11.68	9.69	7.28	6.31	8.94	8.99	10.04	8.42
June	7.94	8.71	13.34	10.44	12.75	10.62	7.94	6.97	9.34	8.75	9.58	8.21
July	7.86	8.13	13.23	10.53	11.12	10.05	8.04	7.60	8.84	8.68	9.25	8.59
August	7.12	7.57	10.98	8.59	12.11	9.59	7.70	6.95	8.37	8.07	8.61	8.92
September	6.86	7.12	9.01	8.08	8.39	7.92	6.59	6.22	7.29	6.69	6.93	7.01
October	6.24	7.82	9.00	8.08	7.67	7.36	6.05	6.61	7.66	6.64	6.42	7.26
November	4.57	5.77	6.74	6.75	6.09	5.47	4.79	5.26	6.72	5.91	6.32	5.75
December	5.30	6.13	7.66	7.83	7.26	6.49	4.54	5.13	6.29	6.16	6.32	5.85

3.6 Network pricing

Electricity distributors recover the cost of owning and operating their electricity distribution networks through pricing for those services. They are required by the Commerce Commission to publish their pricing methodologies and prices. The prices, and structure of prices, used in this analysis were obtained from each distributor in each of the areas considered, as listed below.[6]

1. Auckland: Vector (pricing from the Auckland network was used)
2. Hamilton: WEL Networks
3. Tauranga: Powerco (pricing from the Powerco East, Tauranga network was used)
4. Napier: Unison (pricing from the Hawke's Bay network was used)
5. Wellington: Wellington Electricity Lines Ltd
6. Nelson: Network Tasman (Network Tasman pricing was used rather than Nelson Electricity as it covers a wider area and most of the businesses considered)
7. Christchurch: Orion
8. Dunedin: Aurora Energy (pricing from the Dunedin network was used)

[6] A small number of sites were outside the area of the distributors listed that cover the eight main centres. In these cases, the nearest distributor was used. This is clearly an approximation. None of these sites are considered in the detailed discussion in later sections.

Electricity distributors also recover from customers the cost of the transmission network and services, which Transpower charges each distributor for.

Pricing to customers is typically arranged by category, with categories based on customer size (maximum demand and/or fuse capacity). Distributor prices to commercial customers may change in share between fixed, volume, and peak charges between these categories. For example, if customers use specific assets, cost recovery is weighted towards fixed charges and away from volume charges – as may be the case with larger customers. However, peak charges may still be used to indicate the cost of providing additional capacity. Use of common assets by customers tends to lead to recovery by volume and peak based charges, and recovery of transmission charges is sometimes weighted towards peak charges.

Moreover, the nature of distributor charges, and whether they recover more from fixed charges, volume charges, or peak charges, and the nature of their peak periods, depends on how their networks are used and issues facing each distributor. For example, Upper South Island distributors (Mid Canterbury and above) have consistently avoided transmission upgrades to the region by weighting transmission charges to coincident peak periods that align with high transmission network usage as well as high usage within their own networks. These peak periods are set in real-time or ex-post as determined by Transpower. Other distributors provide specific peak periods that reflect peak use of their networks. For example: (1) a peak period throughout the day that reflects high day-time usage by many commercial customers and high cooling load in the summer; or (2) a narrow peak period in the morning and evening, with higher peak charges in the winter, reflecting winter heating and lighting peaks in the morning and evening.

Generally, electricity distributor prices to commercial customers can be classified by charge listed in Table 6, each of which can further be classified (for example, by the actual definition of a peak period). These prices and price structures were implemented in the model to determine the network charges with and without solar, and therefore the network cost savings for each site. A summary of the eight electricity distributor prices and price structures, by commercial customer category, and with implementation notes is given in Appendix Three.

The model created for this study specifically disallowed movement of a customer from one category (customer size) to another based on any peak demand reduction resulting from coincident solar generation. Instead, it derived all benefit from the charges listed below. This was on the assumption that such peak demand reduction may not be achievable over time. Reasons for this include: solar generation not being present due to system outage, the reduction in solar capacity over time (as per panel degradation), and there may be specific fixed asset costs involved in supply that solar does not avoid, particularly for larger customers.

Table 6: Electricity distribution business charges.

Charge	Units	Model Implementation Notes
Fixed Charge	$/day	Not implemented in the model, as solar does not affect this charge.
Fixed capacity charge	$/kW/day, or $/kVA/day	Not implemented in the model, as solar does not affect this charge.
Nominated maximum demand charge	$/kW/day, or $/KVA/day	Not implemented in the model for large customers, as the maximum demand-determined capacity of the assets supplying a large customer is not reducible by retro-fitted solar.
Anytime metered maximum demand charge	$/kVA/day, $/kVA/month, $/kW/day, or $/kW/month	Implemented for those distributors who have this charge.
Coincident peak charge	$/kW/day, $/kW/month, $/kVA/day, or $/kVA/month	Implemented for the three distributors who have this charge. This required implementing the peak time periods, which included: • Specifically determined peak periods, which vary from year-to-year, and are declared ahead of real-time • Ex-post determined peak periods, such as Transpower's Regional Coincident Peak Demand periods
Peak charges for a fixed peak period	$/kW/day, $/kW/month, $/kVA/day, or $/kVA/month	Implemented for those distributors who have this charge, which is most. This required implementing the peak time periods, which included: • 8am to 8pm period • Narrow peak periods in the morning and evening • Broad peak periods in the morning and evening
Volume charge	$/kWh	Either an anytime volume charge or time-of-use volume charge. Whether anytime or time-of-use may also depend on the commercial customer category. Time of use periods include:[7] • Weekdays / Nights and Weekends • Summer Day / Summer Night / Winter Day / Winter Night • Peak / shoulder / off-peak • Peak / off-peak Where ambiguous, the anytime charge was used which is generally more conservative in valuing solar.

3.7 Solar modelling

A proprietary model was used to model a generic PV system, as per Miller (2020), but with the use of fixed bearing and tilt in the current work. This has an allowance for 13.5% losses, to account for inverter and wiring losses, module soiling, module mismatch, and self-shading. Sensitivity to module bearing and tilt were investigated.

[7] Time-of-use periods, if any, depend on the nature of network load in the distributors's area and their philosophy to recovering their network costs.

For the majority of results presented in this report, and unless otherwise noted, the irradiance data used is from NIWA's SolarView system, which uses a Typical Meteorological Year (TMY). These TMYs consist of hourly records for an artificial year created from twelve representative months, with the chosen months each typical of that month from data records over a period of ten years or more (LIley 2008). This data therefore has the advantage of representing the climate at the site in question, which is an important consideration when estimating financial returns from solar over a 25 year period.

The TMY data were selected for the centre point of each of the eight main centres considered. This ignores the exact location of the site, and any shading resulting from topography or adjacent buildings. As the source data was hourly, it was linearly interpolated to half-hourly for the model.

Capacity factors of solar in each centre, based on the Typical Meteorological Years, and using the generic PV system model noted, are given in Table 7 for the first year of operation of the modules. The model assumes a 0.8% per annum degradation in module performance from that of the previous year over the 25 years of operation; this means that the degradation is slightly non-linear.

Table 7: Capacity factors by centre (north facing modules with a 15° tilt) in the first year of solar operation (2022, which includes one year of module degradation).

Centre	Capacity Factor
Auckland	0.155
Hamilton	0.151
Tauranga	0.154
Napier	0.157
Wellington	0.149
Nelson	0.164
Christchurch	0.143
Dunedin	0.125

A single Typical Meteorological Year (for each centre) was used for every year of the 25 year analysis, although considerable variation in solar energy does occur from year-to-year. This is shown in Figure 5, which plots capacity factor against calendar year for model runs using calendar year data from satellite observations and ground measurements over the period from 2007 to 2019 inclusive.

This second source of data was used to compare load versus modelled solar output for the 2019 year (in which the load occurred) as discussed in the next sub-section.

3.8 Relationship between solar and load

At the beginning of this study it was hypothesised that there may be some correlation between solar irradiance and consumption, and perhaps also peak load, for sites with high refrigeration or air-conditioning requirements. Were this to be the case, it could lead to higher financial returns from solar for such a site.

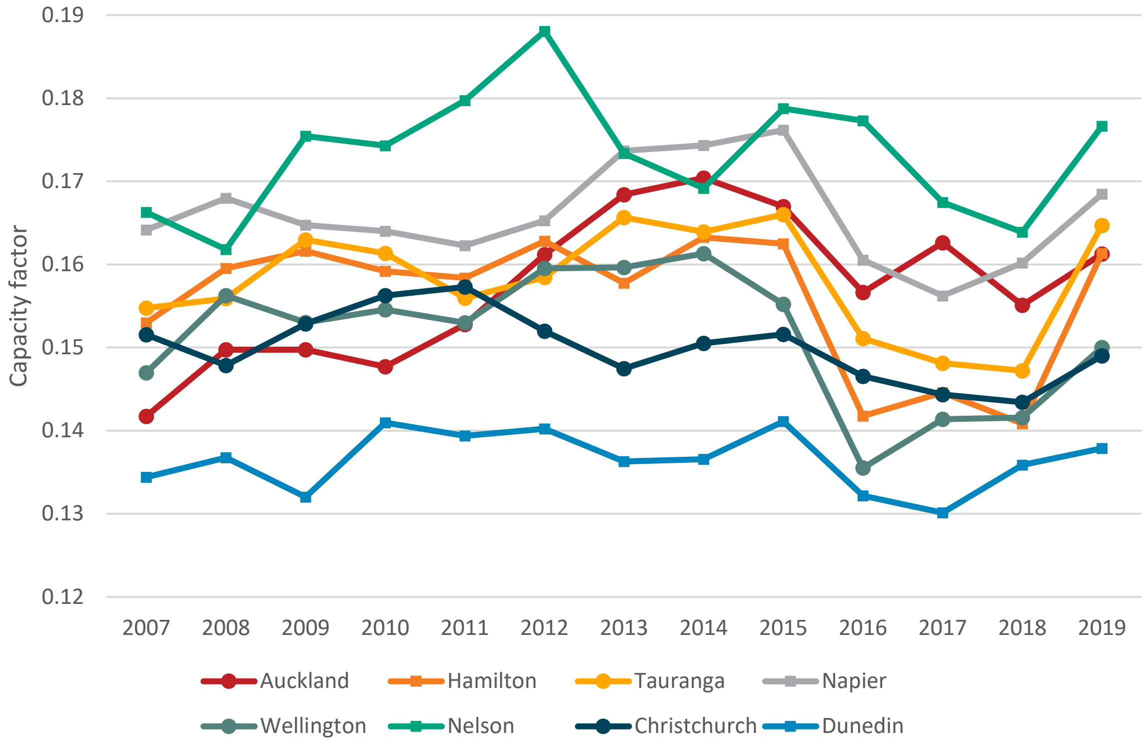


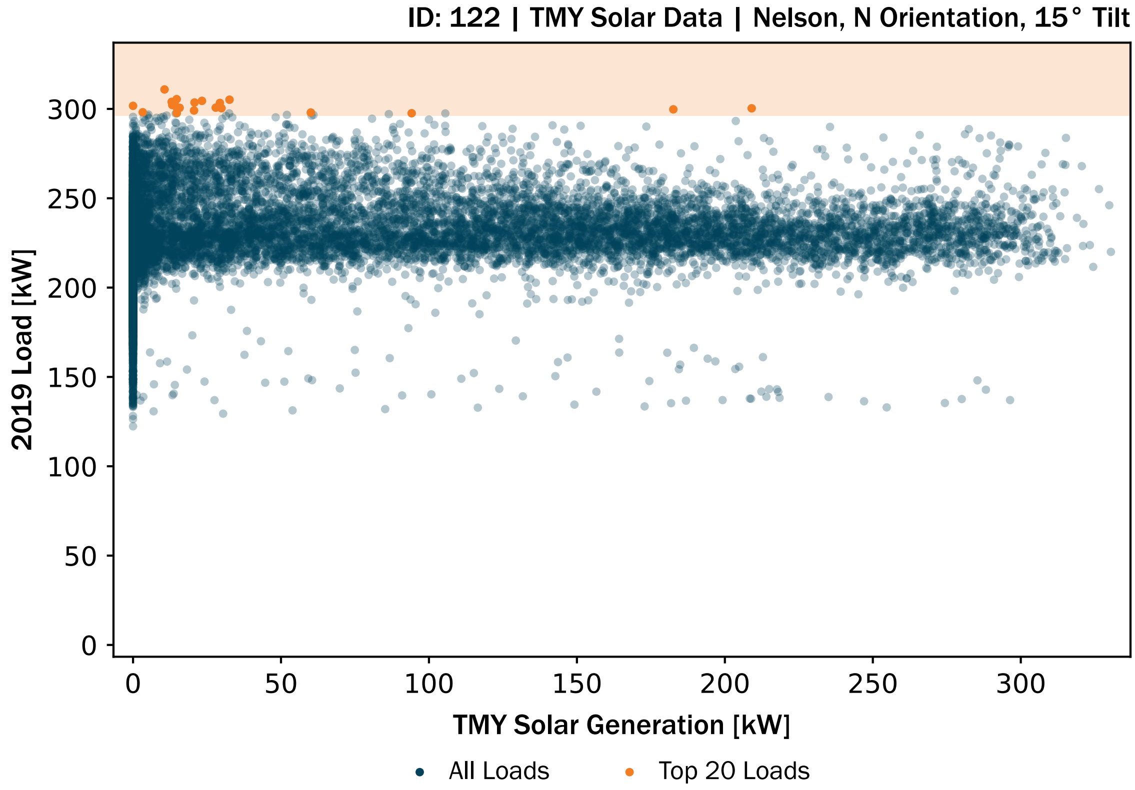
Figure 5: Variation in capacity factor between years (north facing modules with a 15° tilt). Note that a different data set is used to the capacity factors given in Table 7, hence there is some variation between areas.

The use of Typical Meteorological Year irradiance data would capture some of this potential correlation, specifically that resulting from seasonality, but would not capture that resulting from specific weather events. As such, some investigation was conducted to determine the significance of this effect.

This is shown graphically in Figure 6, which plots 2019 load versus Typical Meteorological Year solar generation in the top graph, and 2019 load versus 2019 solar generation in the bottom graph, for a grocery retail site in Nelson in both instances. Two points are clear: First, there is no strong correlation between load and modelled generation (this being related to irradiance), as would be indicated by a general upwards trend in the data from bottom left to top right. Second, there is no obvious increase in the correlation between load and generation when calendar year irradiance data is used instead of TMY data. This would have been indicated by the top 20 loads (indicated in orange) being clustered more towards the right in the bottom graph, as compared to the top; indeed, the opposite appears to be the case for this example.

The significance of this modelling choice (calendar year vs TMY data) is fully examined in Section 5.2 for the grocery retail company, with this case being selected because of the moderate to high refrigeration and air conditioning load, and the availability of data for eight similar sites across NZ. As shown there, the impact on the predicted financial performance is small, with Internal Rates of Return varying by less than about 0.5 percentage points. This substantiates the use of the TMY data throughout this study.

As a final comment on the choice of irradiance data, we note that an alternative approach would be to use longer time series for both load and solar, spanning years. This has its own limitations, as more historical load data may be even less representative of future load than 2019 in this case.



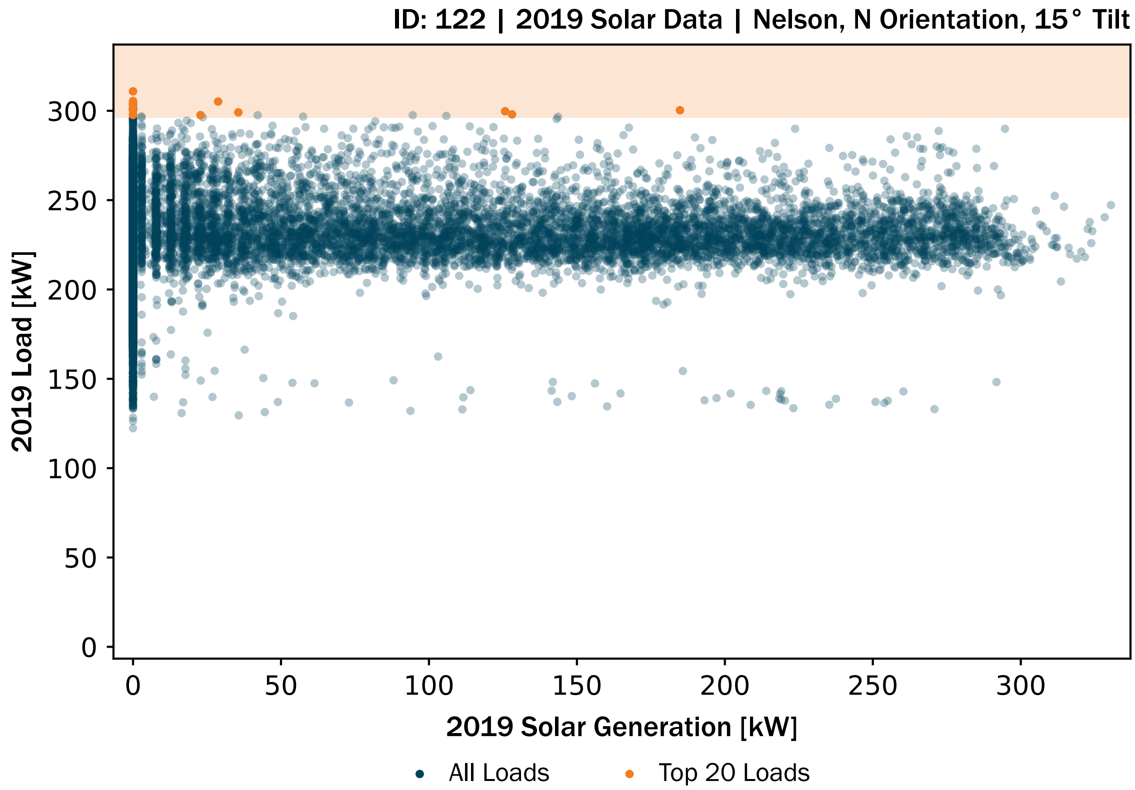


Figure 6: 2019 load versus Typical Meteorological Year solar generation (top) and versus 2019 solar generation (bottom) for a grocery retail site.

3.9 Roof area requirements and solar module weight

As discussed earlier, in assessing the capacity that gives the maximum IRR for each business, this analysis does not consider available roof area, nor the ability of the building to bear the weight of the modules or withstand wind loadings. However, as an indication, Table 8 gives the roof area required at various module layout power densities, as well as the weight of modules. This is based on the JA Solar JAM60S10 320-340/PR module which has a capacity of 340 Wp, physical dimensions of 1.689 x 0.996 metres, and weight of 18.7 kg. Other modules will have similar power-area and power-weight ratios.

Power density depends on module layout such as spacing between modules. The highest density used in Table 8 of 178 Wp-dc/m² is based on array mounted flush with the roof, in 11 columns of two modules wide and 20 modules high, with a 0.5 metre gap between each column of two modules for maintenance access. This is a high density, as other roofs may require tilting of panels and therefore more space between them to avoid shading. Hence lower densities of 130 Wp-dc/m² and 100 Wp-dc/m² are given in the table also. The analysis has assumed a roof slope of 15°, although also considers sensitivity to ±7.5° from this slope.

Table 8: Roof area and loading requirements at various power densities.
Module weight does not include mounting hardware, cabling, and inverters.

Capacity (kWp-dc)	Roof area required (m²) at each power density (Wp-dc/m²) given			Number of modules	Module weight (tonnes)
	178	130	100		
10	56	77	100	30	0.6
20	112	154	200	59	1.1
50	281	385	500	148	2.8
100	561	769	1,000	295	5.5
200	1,123	1,538	2,000	589	11.0
500	2,807	3,846	5,000	1,471	27.5
1,000	5,614	7,692	10,000	2,942	55.0

3.10 Calculation of internal rate of return and levelised cost of energy

The IRR was determined from the discount rate at which NPV was equal to zero. The NPV calculation is over a 25 year system lifespan, using the formula:

$$NPV = dcfEnergyCostSaving + dcfNetworkCostSavings + dcfSpotSales - capitalCost - dcfOMCost - dcfExportCost - dcfTaxCost + dcfDepTaxShield + residualValue.$$

Where:

$dcfEnergyCostSaving$ is the avoided cost of retail energy purchases, discounted to a present value in the investment year. Retail energy purchase cost savings in each year were calculated according to Figure 2, and occur whenever there is coincident load and generation. If site load exceeds generation then the solar generation (kW) is multiplied by the retail price at each half hour ($/kWh) and divided by two (to convert kW to kWh). Alternatively, if generation exceeds the site load then the site load (kW) is multiplied by the retail price ($/kWh) at each half-hour and divided by two (to convert kW to kWh).

Note that in the former case there will be import from the grid, while in the latter case there will be export to the grid.

The result at each half-hour is then multiplied by a ‘loss factor’ of 1.005 and summed over all half-hours. The loss factor is an assumed quantity and when above 1.0 it accounts for an effective decrease in distribution system losses from solar generation. This would be assigned by the distributor, at their discretion, and usually applied to broad areas. Therefore, this improvement in loss factor may not actually be passed through to the business that owns the solar asset.

$dcfNetworkCostSavings$ is the avoided network costs, calculated according to each distributor’s pricing structure and prices, as discussed in Section 3.6, and discounted to a present value in the investment year.

$dcfSpotSales$ is the income from the sale of exported energy at the spot price, discounted to a present value in the investment year. Spot sales in each year are calculated by multiplying the exported solar generation (kW) by the nodal spot price ($/kWh) at each half-hour and dividing by two (to convert kW to kWh). This is then summed over all half-hours of the year and multiplied by the loss factor of 1.005.

$capitalCost$ is the solar installation cost, in the investment year, determined by multiplying the solar capacity (kWp) by the per unit rate ($/kWp) given in Figure 4.

$dcfOMCost$ is the operation and maintenance (O&M) cost in each year discounted to a present value in the investment year. This is determined in each year by multiplying the solar capacity (kWp) by the annual operation and maintenance unit cost. The model uses an O&M unit cost of 20 $/kWp/annum.

$dcfExportCost$ is the cost charged by the retailer for exported energy, discounted to a present value in the investment year. The export cost at each half-hour is calculated by multiplying the exported energy (kWh) by the spot export fee (5 $/MWh). This is then summed over the year to give the annual figure. The spot export fee represents the margin taken by the retailer for trading the exported energy on the wholesale spot market, which would not be possible without a retailer, or would require the commercial business to become a trader in the wholesale market with the associated costs.

$dcfTaxCost$ is the annual tax cost in each year discounted to a present value in the investment year. The annual tax cost is determined from the annual contribution to profit by the solar system, through lowering the businesses energy purchase costs and contributing to revenue. This is the corporate tax rate (28%) multiplied by the sum of annual energy cost savings, network cost savings, spot sale revenue less export cost, and O&M cost.

$dcfDepTaxShield$ is the annual reduction in profit, and therefore tax, through annual depreciation of the investment in the capital solar installation, discounted to a present value in the investment year. The solar depreciation rate of 16% each year is used (obtained from the Inland Revenue), using a Diminishing Value calculation.

$residualValue$ is the residual value of the solar installation after 25 years. It is assumed to be zero.

The equation for levelised cost of energy (LCOE) is

$$LCOE = \frac{capitalCost + dcfExportCost + dcfOMCost + dcfTax - dcfDepTaxShield - residualValue}{dcfEnergy},$$

where

$dcfEnergy$ is the energy produced by the solar system in each year discounted to a present value in the investment year.

4 Case study results

This section presents a summary of results for all case studies, and a detailed analysis grouped by load type.

4.1 Companies assessed

Eleven companies provided data for the study, with individual sites (ICPs) classified into fifteen different types of load. Descriptions of these types of load are provided in Table 1 above, with Table 9 below providing a summary of the distribution of these sites across the eight centres considered in the study. As shown, big box retail and grocery retail sites were located in all centres, while most load types were represented in Auckland. Locations are Auckland (AK), Hamilton (HN), Tauranga (TR), Napier (NR), Wellington (WN), Nelson (NN), Christchurch (CC), and Dunedin (DN).

In some cases, multiple adjacent ICPs were summed, as if they were single ICPs. These are noted in the individual case studies as 'total', but this would require re-configuration of the on-site electricity connection, or the implementation of a specific trading agreement with the retailer which may or may not be practical or available. It is therefore unlikely that this 'total' load would be available for solar in the manner described in Section 2.1. The exception to this is Site 162 (manufacturing), which is the total of two parallel meters supplying the site.[8]

Table 9: Number of sites by load type and location. Locations are Auckland (AK), Hamilton (HN), Tauranga (TR), Napier (NR), Wellington (WN), Nelson (NN), Christchurch (CC), and Dunedin (DN).

Load type	AK	HN	TR	NR	WN	NN	CC	DN	Totals
Big box retail	27	5	4	3	7	4	11	4	65
Retail	8	5							13
Grocery retail	1	1	1	1	1	1	1	1	8
Food market	2				1		1	2	6
Cool store				1		3			4
Greenhouse		2							2
Corporate office	5				7				12
Retail warehousing	3						1		4
Warehousing	1		1	1			5		8
Production	2								2
Manufacturing	3				4				7
Education	1								1
Waste water treatment	8								8
Water supply	3								3
Dairy farm							1		1
Totals	64	13	6	6	20	8	20	7	144

[8] Note that 144 sites were considered in the study, and that these were selected from a larger database which included sites outside the eight centres, hence the use of identifiers above 144.

Each company provided half-hourly consumption data for each site. For some companies this spanned several years, although for most the only complete calendar year was 2019 and part of 2020. 2020 was not considered, as it was not a typical year due to the COVID-19 lockdown, hence 2019 half-hourly load was used for all companies. For the purpose of determining network charges, some companies provided both kWh and information required to determine kVA. In some cases, average kW quantities were provided directly by the company. Details of each site considered are given in Section 4.3 and Appendix Four.

4.2 Summary results

A summary of average internal rate of return by load type and location is given in Table 10. These show a general trend towards higher IRRs in centres with higher solar capacity factors (from Table 7). However, it is difficult to say this definitively due to differences in distribution pricing between centres – this is discussed further in Section 5. Levelised cost of energy is summarised in Table 11. Average solar capacity, such that IRR is maximised, is given in Table 12. This helps explain the LCOE results, as per unit solar costs are higher at lower capacities, and decrease substantially at higher capacities, according to Figure 4. Average site load is summarised in Table 13. With all of these tables, the averages for each load type across all locations (rightmost column), and averages for each location across all load types (bottom row) will be biased by the load types and locations included in the sample, and should therefore be treated as broadly indicative only.

Table 10: Average internal rate of return by load type and location.

Load type	AK	HN	TR	NR	WN	NN	CC	DN	**Mean**
Big box retail	4.3%	4.8%	5.3%	2.2%	2.9%	5.0%	5.8%	0.6%	**3.9%**
Retail	5.8%	4.2%							**5.0%**
Grocery retail	5.0%	3.5%	6.5%	3.0%	2.6%	5.8%	3.2%	1.1%	**3.8%**
Food market	5.1%				2.6%		6.8%	1.7%	**4.0%**
Cool store				4.6%		5.6%			**5.1%**
Greenhouse		6.3%							**6.3%**
Corporate office	6.5%				3.1%				**4.8%**
Retail warehousing	4.8%						5.7%		**5.2%**
Warehousing	6.3%		3.3%	2.0%			4.7%		**4.1%**
Production	6.6%								**6.6%**
Manufacturing	8.4%				3.3%				**5.8%**
Education	6.8%								**6.8%**
Waste water treatment	5.2%								**5.2%**
Water supply	6.8%								**6.8%**
Dairy farm							4.4%		**4.4%**
Mean	**6.0%**	**4.7%**	**5.0%**	**3.0%**	**2.9%**	**5.5%**	**5.1%**	**1.1%**	**5.2%**

Table 11: Average levelised cost of energy (c/kWh) by load type and location.

Load type	AK	HN	TR	NR	WN	NN	CC	DN	Mean
Big box retail	19.0	18.4	17.8	16.1	17.5	17.1	19.9	20.3	**18.3**
Retail	18.5	15.4							**16.9**
Grocery retail	16.2	16.5	17.0	15.1	16.0	15.8	16.9	18.5	**16.5**
Food market	20.6				17.2		18.9	17.0	**18.4**
Cool store				13.9		16.6			**15.3**
Greenhouse		19.5							**19.5**
Corporate office	16.4				15.4				**15.9**
Retail warehousing	16.2						19.9		**18.0**
Warehousing	15.3		14.6	15.8			17.4		**15.8**
Production	15.4								**15.4**
Manufacturing	15.4				14.6				**15.0**
Education	15.5								**15.5**
Waste water treatment	18.4								**18.4**
Water supply	17.2								**17.2**
Dairy farm							21.9		**21.9**
Mean	**17.0**	**17.4**	**16.5**	**15.2**	**16.1**	**16.5**	**19.1**	**18.6**	**17.2**

Table 12: Average solar capacity (kWp) by load type and location.

Load type	AK	HN	TR	NR	WN	NN	CC	DN	Mean
Big box retail	77	192	215	210	194	160	141	173	**170**
Retail	199	536							**367**
Grocery retail	350	300	330	360	330	330	330	340	**334**
Food market	10				200		290	670	**293**
Cool store				1000		420			**710**
Greenhouse		105							**105**
Corporate office	500				603				**551**
Retail warehousing	343						140		**242**
Warehousing	500		470	260			426		**414**
Production	500								**500**
Manufacturing	1000				730				**865**
Education	500								**500**
Waste water treatment	256								**256**
Water supply	503								**503**
Dairy farm							10		**10**
Mean	**395**	**283**	**338**	**458**	**411**	**303**	**223**	**394**	**388**

Table 13: Average site load (kW) by load type and location.

Load type	AK	HN	TR	NR	WN	NN	CC	DN	**Mean**
Big box retail	65	73	85	79	89	61	75	70	**75**
Retail	209	263							**236**
Grocery retail	254	215	206	199	218	225	208	217	**218**
Food market	98				92		160	235	**146**
Cool store				645		358			**501**
Greenhouse		79							**79**
Corporate office	522				134				**328**
Retail warehousing	206						92		**149**
Warehousing	350		279	101			234		**241**
Production	1053								**1053**
Manufacturing	1804				286				**1045**
Education	391								**391**
Waste water treatment	776								**776**
Water supply	1261								**1261**
Dairy farm							24		**24**
Mean	**582**	**157**	**190**	**256**	**164**	**214**	**132**	**174**	**435**

4.3 Case study results

The following sub-sections expand on the results in the summary tables above, and provide detailed results for each individual case study site. For each load type, the tables are ordered by internal rate of return, with data presented for IRR, LCOE, system capacity, capacity factor, and percentage of self-consumption, as well as metrics relating to the site load.

For the first load type – big box retail – the following figures are also included in this section:

1. Graphs of daily load profiles by month, separated into business days and non-business days, for a single site;
2. A graphical presentation of the financial results for the eight sites with highest IRRs;
3. A financial sensitivity analysis for the four sites with the highest IRRs;
4. A graph showing seven days of load and modelled generation for a single site. This is centred on the day on which peak load coincident with a network peak period occurred;
5. A graph of IRR versus solar capacity, which illustrates how the model optimises system capacity by maximising IRR.

For all other load types, a similar set of figures are included in Appendix Five.

4.3.1 Big box retail (BBR)

Big box retail site results are given in the table below. Site 100 is selected for a more detailed assessment, discussed below.

Table 14: Summary statistics for the big box retail sites. Only the ten highest and ten lowest performing sites for solar are listed.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
100	Hamilton	7.1%	21.0	60	0.151	85%	13	58
107	Hamilton	7.0%	21.1	60	0.151	71%	11	59
42	Tauranga	6.7%	18.7	180	0.154	83%	63	172
86	Christchurch	6.6%	18.8	290	0.143	92%	151	285
87	Tauranga	6.4%	19.0	130	0.154	81%	52	127
13	Christchurch	6.3%	19.0	260	0.143	90%	133	255
0	Auckland	6.3%	15.5	490	0.155	85%	191	484
11	Christchurch	5.9%	19.8	150	0.143	93%	88	195
116	Christchurch	5.8%	20.1	120	0.143	96%	62	153
63	Christchurch	5.8%	20.0	130	0.143	94%	84	188
115	Napier	2.5%	16.1	220	0.157	92%	70	220
48	Tauranga	2.5%	15.5	340	0.154	83%	143	331
54	Wellington	2.5%	16.0	330	0.149	83%	175	321
21	Wellington	2.5%	17.5	170	0.149	76%	71	162
37	Napier	2.2%	16.0	220	0.157	83%	89	219
38	Napier	2.0%	16.2	190	0.157	78%	77	182
66	Dunedin	1.0%	18.4	360	0.125	74%	137	354
19	Dunedin	0.5%	20.7	100	0.125	90%	33	93
18	Dunedin	0.5%	19.7	200	0.125	88%	91	193
94	Dunedin	0.4%	22.5	30	0.125	94%	16	50

Load statistics of big box retail

Figure 7 shows load profiles for Site 100. From this it is clear that daytime load is high, with a degree of variability from day-to-day, while night-time load is substantially lower, with little variability. Furthermore, summer load is higher than winter load.

Financial results of big box retail

The combination of high daytime load and high summer load leads to a good internal rate of return of 7.1%, shown in Figure 8, for a solar capacity of 60 kWp. If this IRR is above the NPV discount rate used by the business, solar will be viable for this business, subject to the assumptions used in the model and approximations set out in Section 3.2.

Figure 9 shows the sensitivities of IRR to a number of inputs. These were obtained for the optimal size system of 60 kWp by varying the inputs between the values given on the left of this figure. Evident from this are the following:

1. Wholesale price inflation and the wholesale price year used, which both relate to the solar export price, make some difference to the IRR results. This is because Site 100, and the other sites shown in Figure 9, do export some solar energy which is sold at the spot price.

2. Retail electricity price inflation makes some difference to the IRR results, because they influence the cost savings / avoided cost by solar offsetting retail purchases.

3. Distribution price inflation makes some difference to the IRR results. The largest impact is for those sites with the highest IRRs.

4. The array tilt and bearing do make some difference to IRR, particularly the tilt. However, the sensitivity to them is relatively low.

5. The largest influence on IRR is from solar system capital cost. This is particularly relevant given that the changes to the capital costs of ± 20% are proportionally smaller than changes to other inputs such as inflation rates.

Peak load of big box retail

The results in Figure 8 show a strong contribution to IRR from network cost savings; in this case, the network cost saving is equal in magnitude to the energy cost saving. The influence of solar on network cost savings can be understood by examining the peak periods in Figure 10. These show the Site 100 load ramping up and ramping down during the peak period applied by the electricity distributor (WEL Networks). They also show some solar generation during these periods. That solar generation is sufficient to reduce the peak demand during the month shown. If this occurs consistently across the months and within other months, it will lead to a reduction in network charges. The peak load shown is in January, with a lower summer peak price applied than the winter peak price. However, there is still a network cost reduction. The full WEL Network charges are given in Appendix Three, which also show a high volume peak price for this size of customer. Reduction of energy during the peak period will also reduce network charges.

IRR and solar capacity relationship of big box retail

The solar capacity that maximises IRR at Site 100 is limited by Site 100's maximum load. It would appear from Figure 11 that IRR continues to increase with capacity, at the solar costs used.

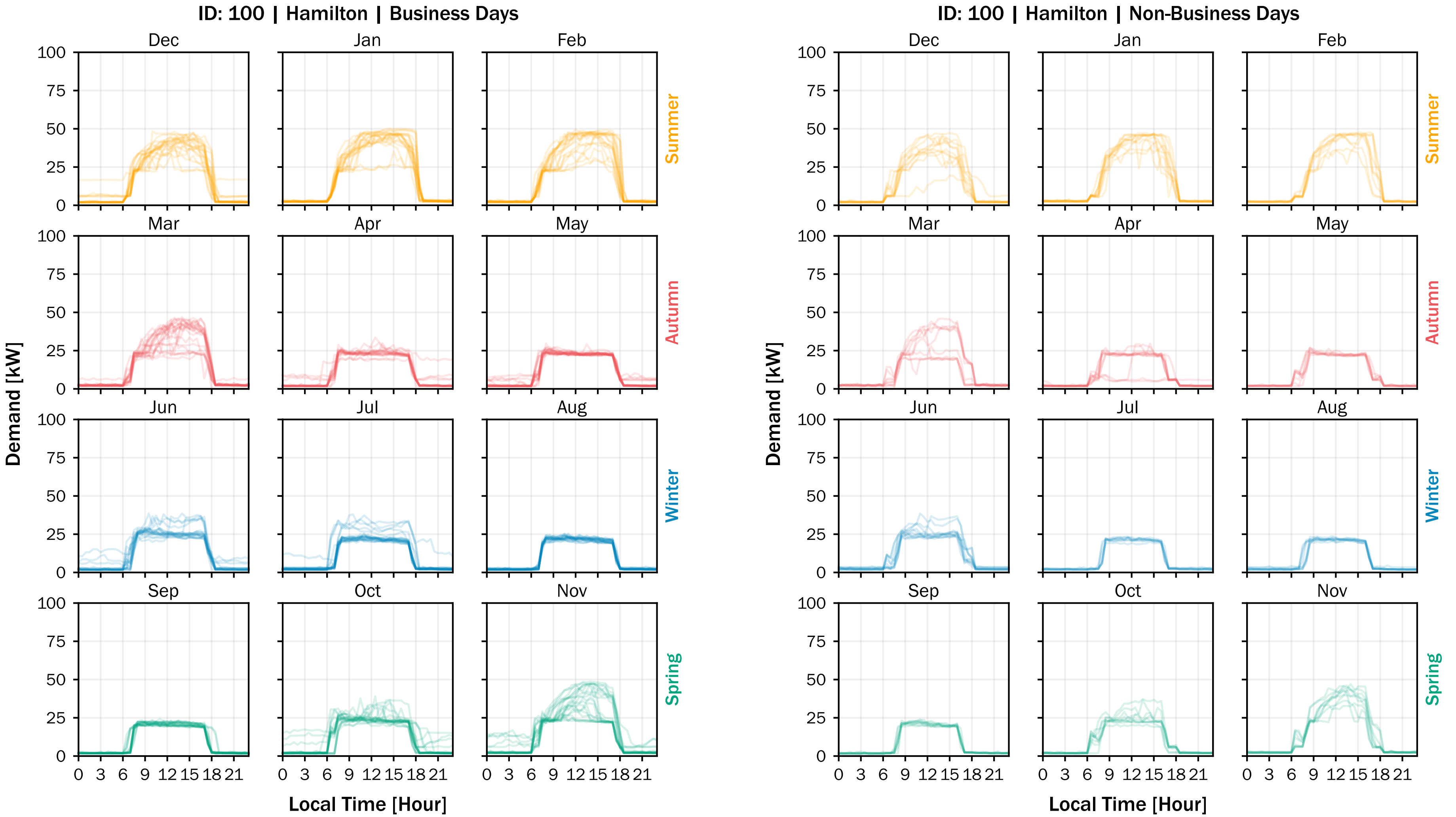
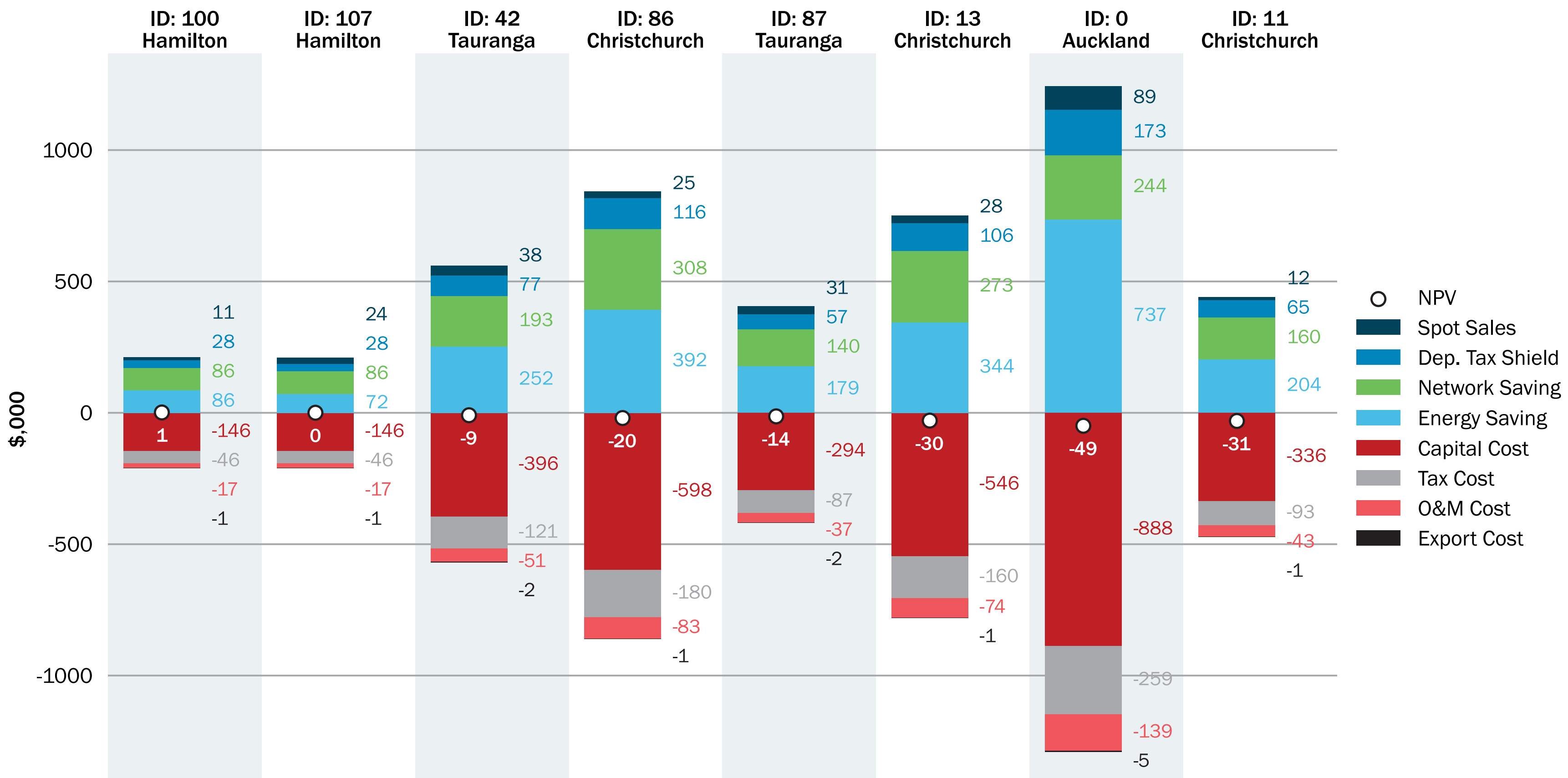


Figure 7: 2019 calendar year load of big box retail Site 100. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



	ID: 100 Hamilton	ID: 107 Hamilton	ID: 42 Tauranga	ID: 86 Christchurch	ID: 87 Tauranga	ID: 13 Christchurch	ID: 0 Auckland	ID: 11 Christchurch
IRR	7.1 %	7.0 %	6.7 %	6.6 %	6.4 %	6.3 %	6.3 %	5.9 %
PV	60 kW	60 kW	180 kW	290 kW	130 kW	260 kW	490 kW	150 kW
Capacity Factor	0.15	0.15	0.15	0.14	0.15	0.14	0.15	0.14
Average Load	13 kW	11 kW	63 kW	151 kW	52 kW	133 kW	191 kW	88 kW
Max Load	58 kW	59 kW	172 kW	285 kW	127 kW	255 kW	484 kW	195 kW
Self Consumption	84.6 %	70.9 %	82.8 %	91.6 %	81.3 %	90.0 %	85.1 %	92.6 %

Figure 8: Financial results of analysis of solar at big box retail Site 100 and another seven sites in descending order of IRR.

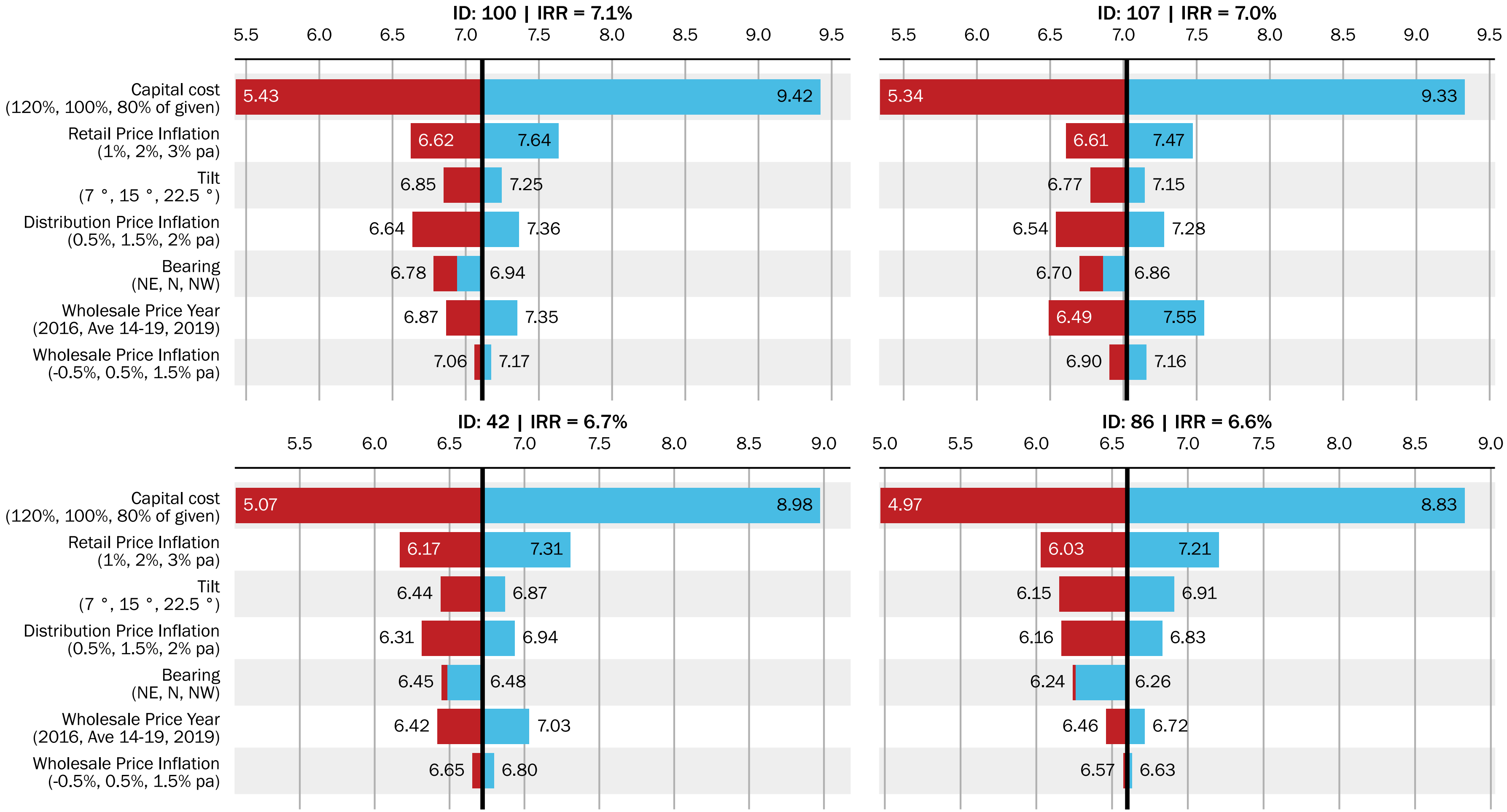


Figure 9: Sensitivity of IRR to inputs for big box retail Site 100 and three other sites.

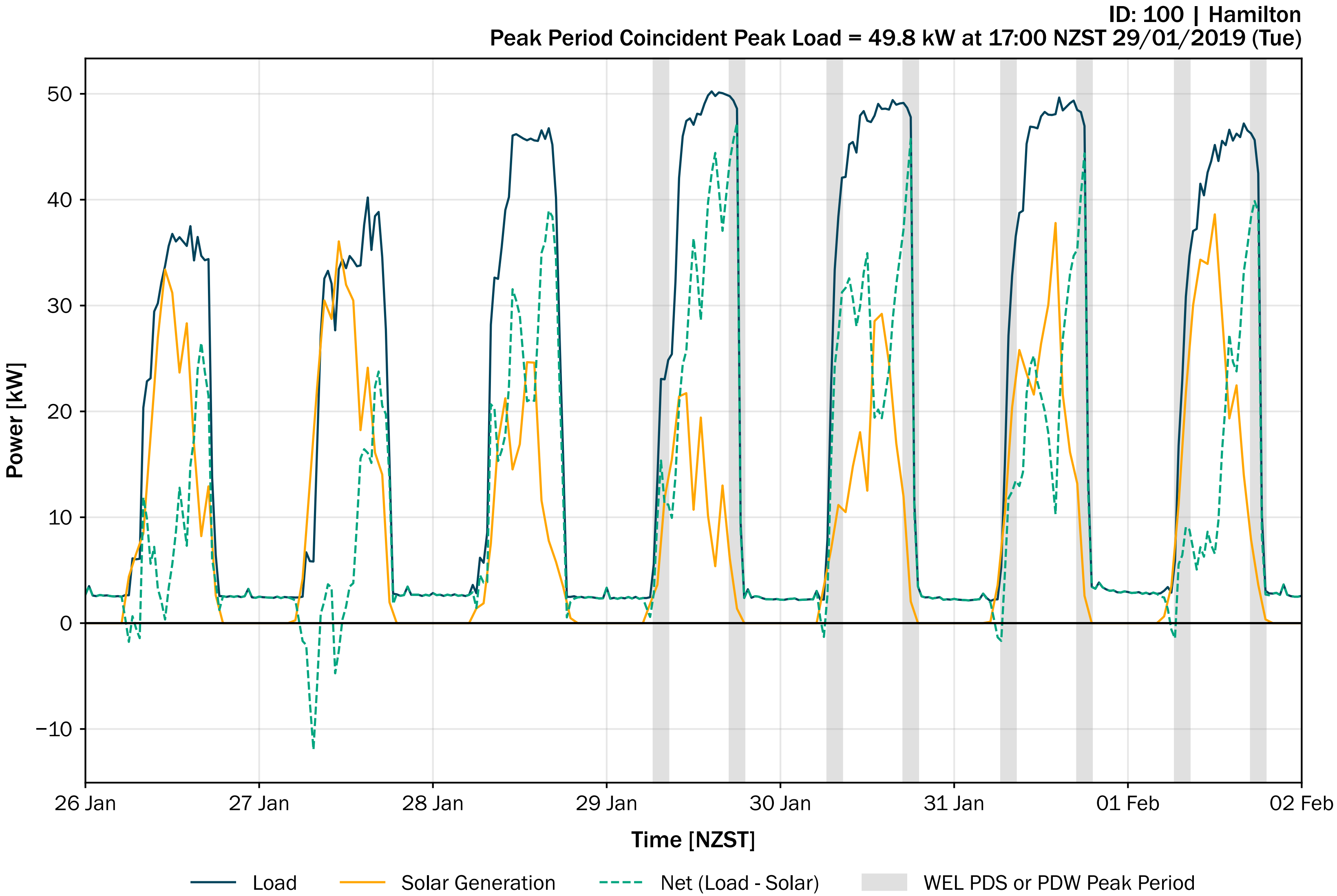


Figure 10: Site 100's load profiles including the time at which the highest kVA load occurred coincident with WEL Network's peak period.

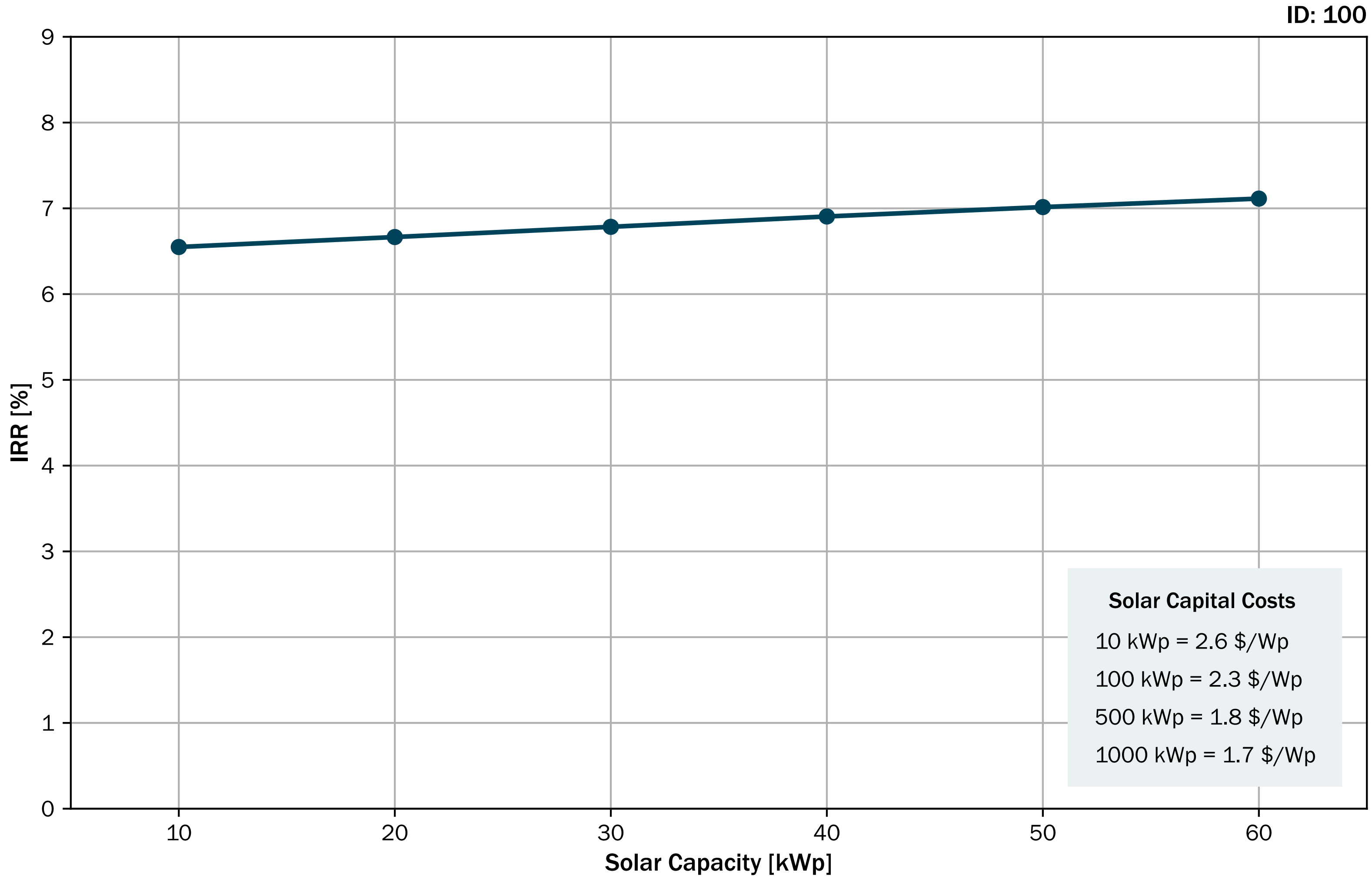


Figure 11: IRR versus solar system capacity for big box retail Site 100.

4.3.2 Retail (RTL)

Results are summarised in the table below for all retail sites. Detailed results for Site 155 are given in Figure 15 to Figure 19 of Appendix Five. Site 155 is selected for further discussion as it is a single site, not a total of multiple sites, as is the case with 156.

Table 15: Summary statistics for the retail sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
156	Auckland	7.6%	15.8	500	0.155	100%	838	2111
155	Auckland	6.5%	15.5	500	0.155	70%	90	600
152	Auckland	6.2%	15.7	450	0.155	96%	172	443
153	Auckland	5.9%	21.0	10	0.155	100%	124	251
149	Auckland	5.6%	20.9	10	0.155	100%	226	444
154	Auckland	5.6%	18.7	100	0.155	99%	80	343
161	Hamilton	5.0%	14.5	1000	0.151	100%	657	1546
159	Hamilton	4.8%	15.4	470	0.151	98%	187	468
150	Auckland	4.7%	20.4	10	0.155	100%	51	112
151	Auckland	4.2%	20.1	10	0.155	100%	95	169
158	Hamilton	4.1%	15.3	450	0.151	99%	200	446
157	Hamilton	3.6%	15.8	390	0.151	86%	126	387
160	Hamilton	3.6%	15.9	370	0.151	97%	144	369

Retail load profiles for the individual Site 155 with the highest IRR (in Auckland) show similar load on business and non-business days, higher load in the summer than winter, and load predominantly between about 8am and 5pm. A solar capacity of 500 kWp at this site gives a good IRR of 6.5%, the highest achieved for the single retail sites considered.

This site achieves export of about 30% of the solar energy generated, possibly because of the lower and shorter winter load profiles. Because of this the IRR is sensitive to the wholesale price and wholesale price inflation. Other than this, sensitivities follow a similar pattern to big box retail sensitivities.

Network cost savings make up a reasonable proportion of cost savings because load is usually highest during the day and within Vector's peak demand period.

4.3.3 Grocery retail (FRWRL)

Results are summarised in the table below for all grocery retail sites. Detailed results for Site 122 are given in Figure 20 to Figure 24 of Appendix Five. Site 122 is selected for further discussion because of the more interesting distribution pricing at Site 122.[9]

[9] Site 120 gains network cost savings by moving it to a lower maximum demand category, which may not be possible in practice. If not possible it would not receive any network cost savings at all. Site 122 is subject to a 'control period' peak distribution price, within the same maximum demand category.

Table 16: Summary statistics for the grocery retail sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
120	Tauranga	6.5%	17.0	330	0.154	99%	206	325
122	Nelson	5.8%	15.8	330	0.164	98%	225	327
117	Auckland	5.0%	16.2	350	0.155	99%	254	350
121	Hamilton	3.5%	16.5	300	0.151	99%	215	299
118	Christchurch	3.2%	16.9	330	0.143	97%	208	330
119	Napier	3.0%	15.1	360	0.157	94%	199	351
123	Wellington	2.6%	16.0	330	0.149	97%	218	329
124	Dunedin	1.1%	18.5	340	0.125	97%	217	332

Grocery retail load profiles of Site 122 show a high load throughout the day from about 4am to 7pm and peaking around 7am. Site 122 is in Nelson/Tasman, with its summer and winter load about the same. The IRR of this site is not high, at 5.8%, although it is the second highest of all Grocery Retail sites throughout the eight centres considered.

IRR sensitivities follow a similar pattern to big box retail.

Network cost savings make up a low proportion of cost savings compared to energy purchase cost savings. This is because load peaks around 7am when solar generation is low in the winter – when the coincident peak periods occur.

The solar capacity was limited by the site's maximum demand, but the IRR continues to increase with solar capacity.

4.3.4 Wholesale food market floor (MKT)

Wholesale food market floor results are shown in the table below, with Site 131 selected for further discussion. Results for Site 131 are given in Figure 25 to Figure 29 of Appendix Five.

Table 17: Summary statistics for the wholesale food market floor sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
131	Christchurch	6.8%	18.9	290	0.143	96%	160	288
132	Auckland	5.7%	20.9	10	0.155	100%	190	344
130	Auckland	4.4%	20.2	10	0.155	94%	6	16
129	Wellington	2.6%	17.2	200	0.149	86%	92	193
133	Dunedin	1.8%	16.9	690	0.125	87%	334	687
134	Dunedin	1.5%	17.1	650	0.125	44%	137	646

The load profiles of this Christchurch Site 131 show similar demand between business and non-business days, with demand at its highest between about 8am to 5pm. Combined with a reasonably high proportion of network cost savings, the IRR is a reasonably good 6.8%. The network cost savings arise from a coincidence of morning peak load and some solar generation at the time of Orion's control periods, and time-of-use charges during the daytime when solar and load are high.

As in the case of grocery retail, solar capacity was limited by the site's maximum demand, although it continues to increase quite steeply beyond the 290 kWp capacity.

4.3.5 Cool store (CLSTR) and Greenhouse (GRNHS)

Results for cool store and greenhouse sites are shown in the table below, with Site 140 selected for further discussion. This site was selected due to it having the highest IRR of sites actually in the distribution area modelled.[10] Detailed results of Site 140 are given in Figure 30 to Figure 34 of Appendix Five.

Table 18: Summary statistics for the cool store and greenhouse sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
135	Hamilton	7.8%	20.2	110	0.151	90%	47	102
140	Nelson	7.2%	14.1	1000	0.164	88%	1024	2854
138	Nelson	5.2%	16.5	250	0.164	48%	45	247
139	Hamilton	4.7%	18.8	100	0.151	100%	112	247
136	Napier	4.6%	13.9	1000	0.157	59%	645	2154
137	Nelson	4.4%	19.3	10	0.164	76%	4	22

Site 140 is in Nelson/Tasman, has a high IRR of 7.2%, and a very high solar capacity of 1 MWp. The load profiles in the Appendix show comparatively very low load in the summer, highest in the autumn and early winter, reducing in spring. When load is high it is high throughout the day, with a peak around midday.

The load profiles show good coincidence of peak load with solar generation and the Network Tasman peak periods. Network charges are concentrated into these periods, and volume-based time-of-use network charges emphasise costs in winter days. As stated earlier, winter load is high during the day, with solar thereby reducing the load and network charges.

The increase in IRR with capacity is still reasonably steep at 1 MWp.

4.3.6 Corporate office (CO)

Results for corporate office sites are given in the table below, with Site 148 selected for further discussion – Site 148's results are given in Figure 35 to Figure 40 of Appendix Five.

[10] Some of the sites analysed in this report were outside the eight main centres, and therefore within another distributor's network area. However, because the model uses only eight distributor pricing models, the nearest distributor was used in these cases. This is clearly an approximation. A small number of sites for other load types also had this occur. None of these sites are considered in the detailed analysis in Appendix Five.

Table 19: Summary statistics for the corporate office sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
148	Auckland	7.6%	15.0	1000	0.155	99%	800	1840
144	Wellington	3.7%	14.3	1000	0.149	70%	291	1349
147	Wellington	3.6%	14.7	730	0.149	66%	177	729
146	Wellington	3.5%	14.8	700	0.149	58%	145	692
143	Wellington	3.2%	14.5	860	0.149	40%	103	853
141	Wellington	3.0%	15.1	460	0.149	69%	138	452
142	Wellington	2.6%	17.1	230	0.149	63%	50	227
145	Wellington	2.4%	17.0	240	0.149	50%	32	235
128	Auckland	6.2%	15.2	500	0.155	99%	339	559
125	Auckland	7.2%	15.7	500	0.155	100%	1221	2447
0	Auckland	6.3%	15.5	490	0.155	85%	191	484
114	Auckland	5.2%	20.7	10	0.155	100%	58	169

Site 148 selected has the highest IRR and is in Auckland. This corporate office load ramps up steeply at around 6-7am all year, and reduces slowly from about 3pm in autumn, winter and spring, but remains high until about 6pm in summer. Business day load is roughly double non-business day load.

IRR is strong at 7.6%, with energy cost savings high from the 1 MWp solar system. Network cost savings, while not as high a proportion as energy cost savings, are still significant, due to the reduction in peak demand by solar around midday as well as volume reductions. The IRR is quite flat from 500 MWp to 1 MWp, with little difference in IRR between these capacities.

The Appendix also includes a seven day load profile for a site in Wellington (Site 145) to contrast with the Auckland site. Even though there is some reduction in load during Wellington Electricity's peak periods, the Customer's size is such that peak charges do not apply, and volume charges are very low with the same charge applying in all time periods. This explains why the Site 145 network cost savings are so low, resulting in a low IRR.

4.3.7 Retail warehousing (RW)

Retail warehousing site results are summarised in the table below, with Site 113 selected for further discussion – its results are given in Figure 41 to Figure 45 of Appendix Five.

Table 20: Summary statistics for the retail warehousing sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
113	Christchurch	5.7%	19.9	140	0.143	84%	92	256
110	Auckland	5.6%	15.5	450	0.155	96%	297	450
112	Auckland	5.1%	16.3	350	0.155	82%	176	345
111	Auckland	3.6%	16.7	230	0.155	85%	144	230

Site 113 is in Christchurch, and has a high morning peak throughout the year, low midday load, and a peak in the late afternoon/evening. The IRR is moderate at 5.7%, with network cost savings making up a slightly lower proportion than energy cost savings. Peak load generally occurs in the morning, coincident with Orion control periods in the winter, but also at a time when solar generation is not very high. Thus most benefit would derive from Orion's volume weekday network prices and little benefit in weekends.

The PV system that gives maximum IRR is 140 kWp although there is very little variation in IRR from 100 kWp to 270 kWp.

4.3.8 Warehousing (WHS)

Results of warehousing sites are summarised below, with Site 166 selected for further discussion – because it is the site with the highest IRR actually within the network area considered.[11] Detailed results are given in Figure 46 to Figure 50 of Appendix Five.

Table 21: Summary statistics for the warehousing sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
168	Christchurch	6.8%	18.8	300	0.143	96%	182	298
166	Auckland	6.3%	15.3	500	0.155	94%	350	701
170	Christchurch	5.6%	20.2	100	0.143	91%	53	96
167	Christchurch	4.6%	15.1	970	0.143	93%	561	971
173	Christchurch	3.4%	16.1	440	0.143	80%	186	432
172	Tauranga	3.3%	14.6	470	0.154	95%	279	465
169	Christchurch	3.0%	17.0	320	0.143	94%	187	312
171	Napier	2.0%	15.8	260	0.157	58%	101	258

Site 166, in Auckland, has fairly constant demand throughout the day, business days and non-business days, as well as between the seasons, but with morning (8am to 11am) and afternoon (3pm to 6pm) dips in load in the winter months.

The IRR is reasonable at 6.3%, with network cost savings a relatively low proportion of cost savings. While solar does reduce peak demand within Vector's peak demand period, energy cost savings are particularly high. The 500 kWp solar capacity gives the highest IRR, with IRR declining beyond this.

4.3.9 Production (Prod)

Results are summarised in the table below for all production sites, although ID 127 is a combination of production and corporate office. Therefore site 126 is shown in more detail, with results given in Figure 51 to Figure 55 of Appendix Five and discussed further below.

[11] Cf. Footnote 10.

Table 22: Summary statistics for the production sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
127	Auckland	7.2%	15.7	500	0.155	100%	1664	3244
126	Auckland	5.9%	15.2	500	0.155	92%	442	930

Site 126 in Auckland has high load throughout the day from around 5am to 9pm in all seasons, with lower demand on non-business days, when it remains at a 'floor' of about 200 kW.

The 500 kWp capacity solar results in a reasonable IRR of 5.9%. Network cost savings are not particularly high due to peak load occurring in the morning and not coincident with Vector's peak demand period. There is some load reduction during the day on business and non-business days, with some export on non-business days.

4.3.10 Manufacturing (MANU)

The manufacturing site results are summarised in the table below. The highest IRR site, 162, is discussed in more detail below, with detailed results in Figure 56 to Figure 60 of Appendix Five.

Table 23: Summary statistics for the manufacturing sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
162	Auckland	8.6%	15.4	1000	0.155	100%	2706	6125
164	Auckland	8.4%	15.3	1000	0.155	100%	1474	4244
163	Auckland	8.3%	15.3	1000	0.155	99%	1232	3195
187	Wellington	3.5%	14.3	1000	0.149	57%	463	1410
188	Wellington	3.5%	15.0	500	0.149	66%	219	606
185	Wellington	3.1%	14.6	740	0.149	52%	234	731
186	Wellington	3.1%	14.7	680	0.149	53%	229	680

The load profiles of the Site in the Appendix show load ramping between about 5am and 9am in summer and autumn, and more rapidly between about 5am and 7am in winter months. Load is substantially higher on business days and typically peaks in the morning on winter days, after which it ramps down slowly.

The peak load profiles graphs in the Appendix show little peak load reduction coincident with peak periods, but some reduction in demand throughout the day, resulting in network energy cost savings and substantial retailer energy purchase cost savings. The maximum IRR is reached at 1 MWp solar capacity, although this is not significantly higher than the IRR at 500 kWp capacity.

4.3.11 Education (EDU)

The single education site's results are summarised below, with details given in Figure 61 to Figure 65 of Appendix Five.

Table 24: Summary statistics for the education site.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
165	Auckland	6.8%	15.5	500	0.155	98%	391	969

Evident from the load profiles in the Appendix is higher load during business days, peaking between about 6am and 6pm. Peak load occurs within the Vector peak period, and coincident with reasonable solar generation. This results in network cost savings, and the solar energy generation in good energy purchase cost savings. Consequently, a reasonable IRR of 6.8% is achieved.

4.3.12 Waste water treatment (WWT) and water supply (WS)

Results for the waste water treatment and water supply plants are shown in the table below (these are from a larger set of sites, with sites already with solar installed not included in this analysis). Site 180, with the highest IRR, is selected for further discussion, with detailed results given in Figure 66 to Figure 70 of Appendix Five.

Table 25: Summary statistics for the waste water treatment and water supply sites.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
180	Auckland	8.5%	16.2	500	0.155	87%	243	986
174	Auckland	7.6%	15.0	1000	0.155	100%	5366	12023
181	Auckland	7.2%	14.9	1000	0.155	100%	3520	5178
177	Auckland	5.7%	15.1	500	0.155	88%	255	526
183	Auckland	5.5%	15.2	500	0.155	56%	183	683
182	Auckland	5.3%	20.7	10	0.155	95%	113	564
184	Auckland	5.0%	20.5	10	0.155	98%	130	692
176	Auckland	4.9%	20.5	10	0.155	100%	34	139
179	Auckland	4.8%	20.4	10	0.155	100%	121	149
175	Auckland	4.7%	20.5	10	0.155	77%	20	122
178	Auckland	3.1%	19.6	10	0.155	99%	11	20

As shown in the load profiles of Appendix Five, load is reasonable constant throughout all days of the year, both business and non-business. However, on business days the load occasionally peaks during the day by as much as five times the base load. This typically occurs around midday (usually in autumn and spring), but on occasion throughout most of the day (usually in winter), and on other occasions mid-morning and mid-afternoon (spring and summer).

Because load peaks throughout the day or within the day it usually coincides with the Vector peak period and high solar generation, thereby giving rise to high network cost savings. Energy purchases are also offset during the day, also giving rise to high energy cost savings.

Given that the site's maximum load is nearly 1 MW, solar up to 1 MWp is considered. However, the maximum IRR is reached at 500 kWp.

4.3.13 Dairy farm (DAIRY)

Results of the single dairy farm assessed are given in the table below. Figure 71 to Figure 75 of Appendix Five give detailed results.

Table 26: Summary statistics for the dairy farm site.

ID	Centre	IRR	LCOE	Solar capacity (kWp)	Capacity factor	Solar self consumption	Site load (kW)	
							Average	Maximum
189	Christchurch	4.4%	21.9	10	0.143	98%	24	101

The load profiles for Site 189 in the Appendix show a load at its peak in summer around 3am to 8am with a second peak around 12pm to 4:30pm. Load reduces substantially in June and July.

The peak load profiles in the Appendix show little contribution to load reduction from solar at the Orion peak period, and because a lot of high load occurs during the night-time when network volume charges are much lower for this size load, there is little in the way of network cost saving available. For the same reason there is little energy purchase cost saving. Consequently the IRR is low at 4.4%.

5 Analysis of case study results

Using the results presented in Section 4 and Appendix Five, this section analyses the underlying drivers of financial performance in order to offer some general conclusions for businesses. The use of 2019 solar data instead of typical meteorological year solar data is also investigated for the grocery retail load type.

5.1 Underlying IRR drivers

Figure 12 graphs the spot sales plus energy cost savings (top) and network cost savings (bottom) normalised to total capital cost (a combination of solar capacity and per unit capital cost) versus IRR for all 144 sites assessed. This shows that spot sales plus energy cost savings remain within a band irrespective of IRR. By contrast, network cost savings increase by a factor of roughly 6 times with IRR, showing a general correlation between IRR and network cost saving.

The correlation between four energy demand ratios and IRR was also investigated, as shown in Figure 13. These demand ratios were: daytime to nighttime, daytime to total, maximum to mean, and summer to winter. However, no clear correlations could be discerned from these, with the IRR being a complex mix of irradiance, network cost saving, energy cost saving, solar capital cost/capacity, customer type, and location.

Given the correlation in Figure 12, we conclude that in many cases it is the network cost savings that determine the economic viability of commercial-scale solar, provided it is located in an area with suitable solar resource and wholesale prices. This can however be overridden by very good energy cost savings and/or spot sales, such as the one site in Nelson/Tasman and a group of sites in Auckland. These all have high load and solar capacity in common – the high solar capacity reduces the solar capital cost sufficiently to allow the energy cost saving and medium network cost saving to yield a high IRR.

Figure 12 also shows areas with clear single groupings of IRR, such as Dunedin and Wellington, both with low IRRs. It would appear that it is difficult to achieve high network cost savings in these areas. This is likely due to poor coincidence of solar resource with coincident peak periods in Dunedin, and essentially no coincident peak charge or time-of-use energy price in Wellington (combined with lower solar resource in both locations).

There are also areas with two distinct groupings of IRR, such as Hamilton and Tauranga. In the case of Hamilton, the group with high IRR fall into the lowest commercial load category of General (below 110 kVA), where WEL Network's strongly differentiated peak, shoulder and off-peak kWh signals apply. The 'big box retail' case study (Section 4.3.1) discusses one of these sites, ID 100, with Figure 10 showing that solar does contribute to load reduction during the narrow WEL Network peak period. This helps explain why the network cost savings are so high in these cases. In the case of Tauranga, network cost savings fall into a group of mid-high network cost savings and no network cost savings. The sites with the lowest network cost saving fall into the Large Commercial category, which has neither a peak charge nor volume charges, just fixed charges (which solar provides no relief from). This explains why the network cost savings are zero in these two cases. As load reduces volume charges are introduced, with a very high distinction between peak and off-peak in the General Commercial (load below 41 kVA) category. Other IRR results appear to vary more continuously, likely due to smoother transitions in prices between load categories.

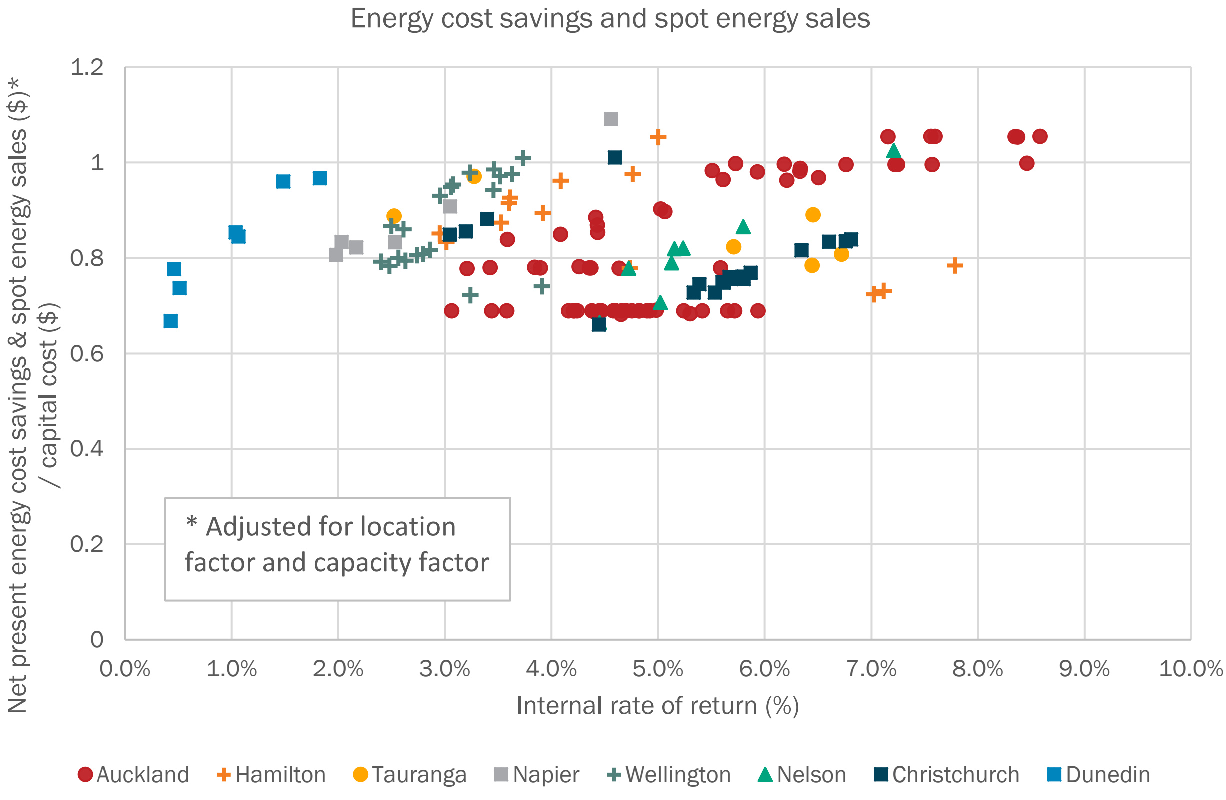
Finally, none of the Napier sites have particularly high IRRs, with network cost savings all low due to Unison's pricing and possibly also because of the limited sample of businesses in Napier.[12] Energy cost savings can however be very high, but the overall IRR lower due to low network cost savings.

The conclusion that in many cases it is the network cost savings that determine the economic viability of commercial-scale solar is an important one for several reasons. Firstly, it highlights the importance of undertaking a detailed analysis of a potential solar installation using half-hourly load data for the business, as the use of average consumption over a day or a month would not show this. This is especially the case for smaller businesses with lower capacity solar. Secondly, it demonstrates that careful modelling of network pricing to understand potential network cost savings is essential in assessing the viability of a commercial solar energy system. While in this analysis a Typical Meteorological Year has been used, better matching of actual solar year with load year might be wise – as indicated in Section 3.8 and investigated further in Section 5.2. However, this would require careful adjustment of the solar generation to account for significant variation in solar capacity factor between years – as shown in Section 3.7.

Another reason why this conclusion is important is that changes to distribution and transmission pricing in the future may markedly change network cost savings, and thereby change the viability of a commercial solar energy system.

A final reason for the importance of this conclusion is that in some cases the electricity distributor's prices are essentially providing a signal to install solar. However, whether a solar energy system will actually translate to cost savings for the electricity distributor requires careful consideration. Otherwise, the electricity distributor pricing may be sending a signal to install commercial solar systems, but not actually gaining any benefit in return.

[12] Unison's peak price in summer, when peak demands occur for most of the businesses and sites, is half the winter peak price, and in almost all cases peak demand is reduced during the morning peak but not during the evening peak. Further, sites above 139 kVA do not receive network cost savings from reduced energy (kWh) through the network.



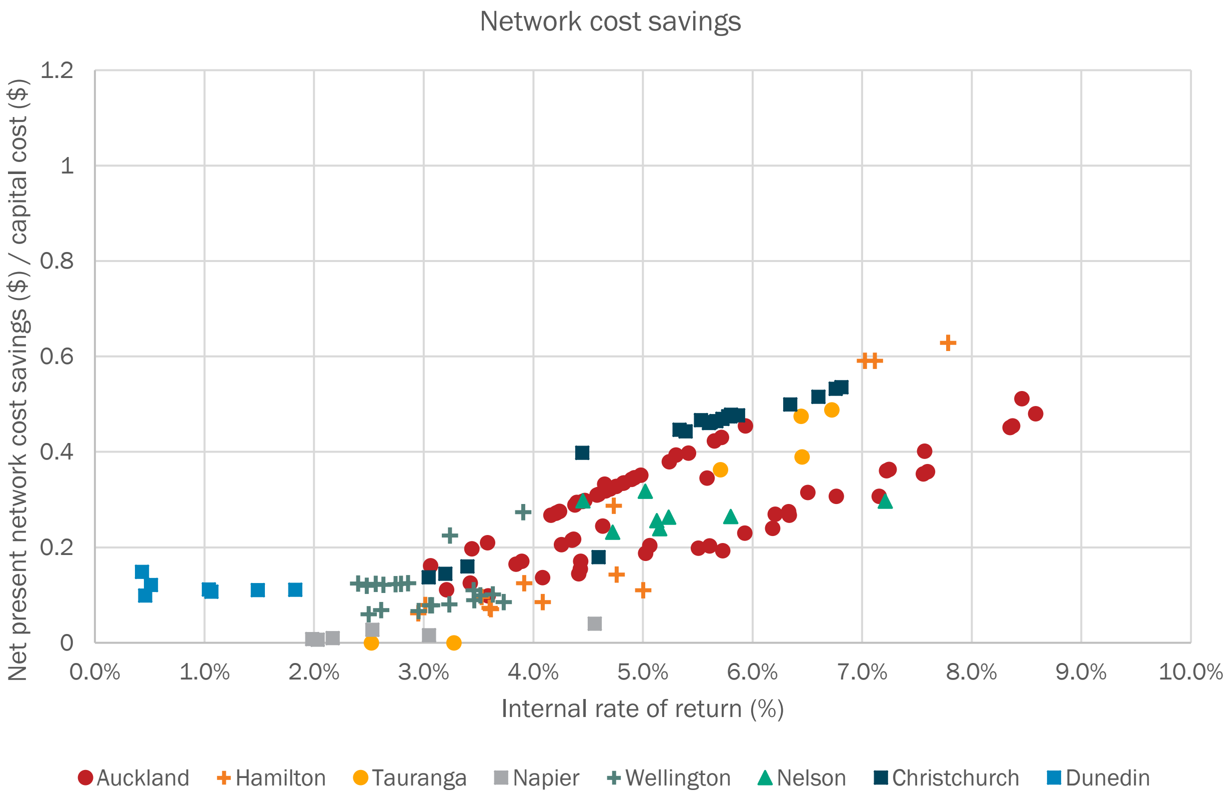


Figure 12: Normalised net present cost savings for all 144 sites assessed. Top: energy cost savings and spot energy sales corrected for capacity factor and spot prices by centre and bottom: network cost savings.

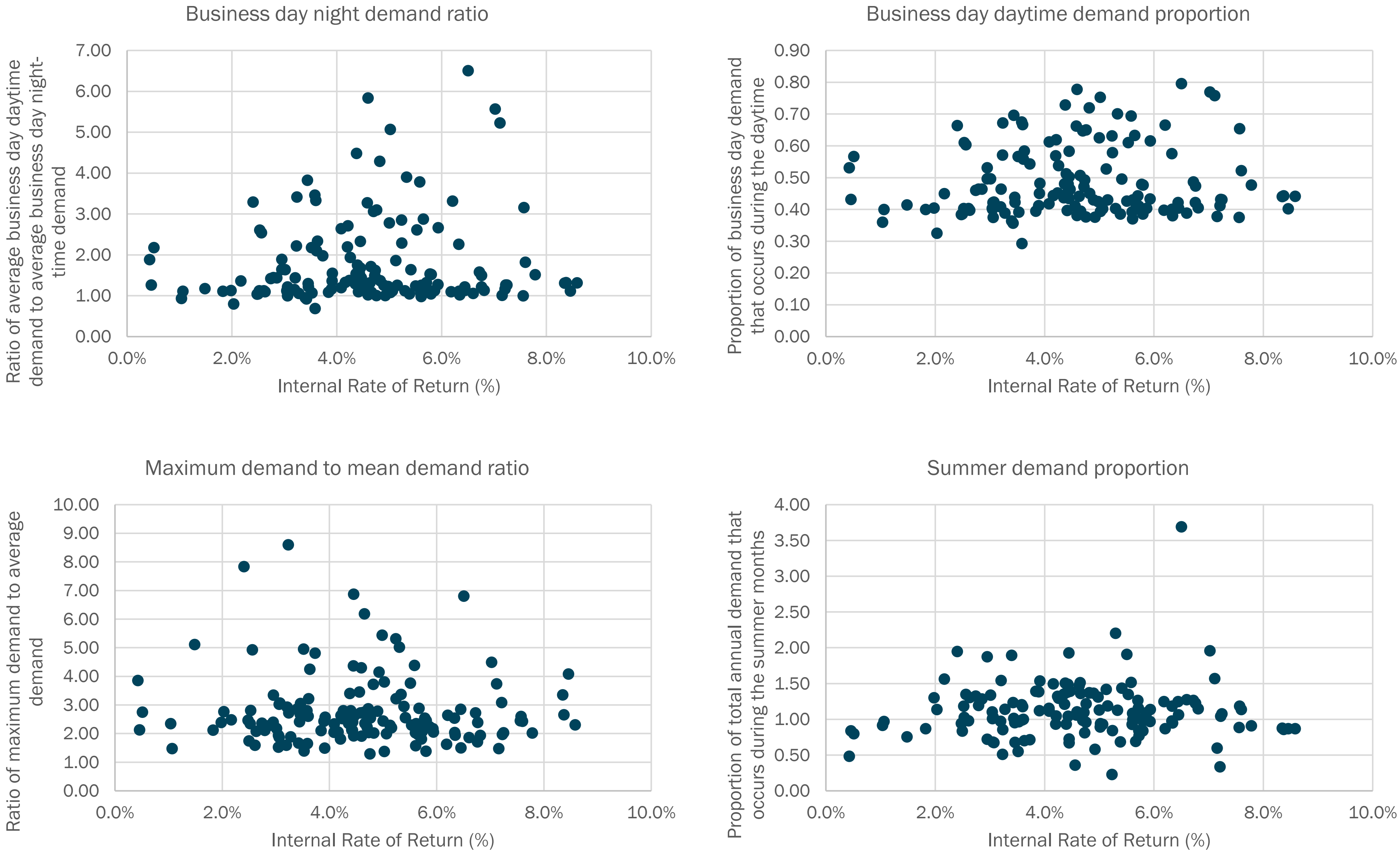


Figure 13: Various demand ratios versus internal rate of return.

5.2 Investigating results using 2019 solar data

It was suggested in Section 3.8 that the use of solar irradiance data for the same year as the load data may give improved financial results due to the two being more correlated. For this reason, the results in this section compare results using Typical Meteorological Year (TMY) derived solar generation (presented in Section 4) with 2019 derived solar generation scaled to the same annual energy as the TMY generation.

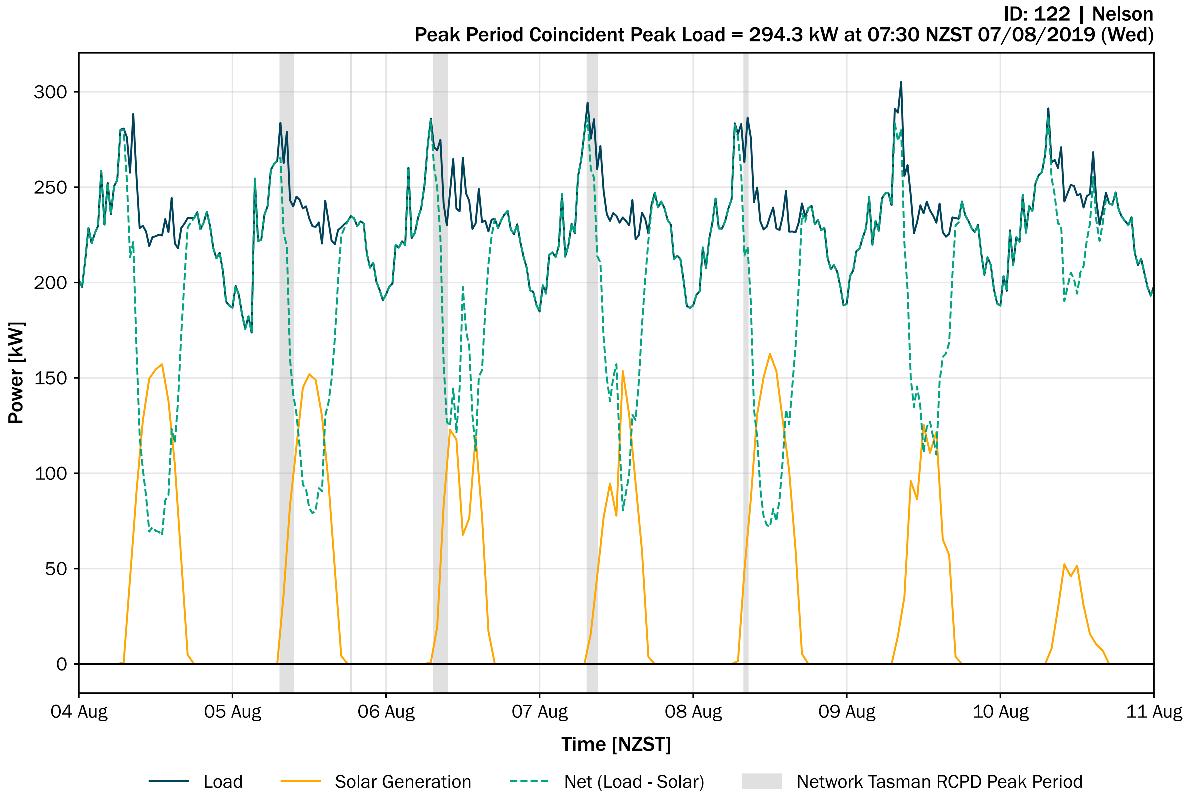
This comparison is performed for one customer, grocery retail, for two reasons. First, the moderate to high refrigeration and air conditioning load was thought to potentially correlate with irradiance more than other load types. And Second, because it had the most similar sites, in terms of average and maximum load, across the eight centres considered, thus allowing for eight TMY vs 2019 calendar year comparisons on similar loads.

Table 27: Results summarising solar performance determined using TMY solar generation and 2019 solar generation, scaled to the annual TMY solar generation.

Centre	System size that maximises IRR (kWp)		IRR (%)		Income ($,000)					
					Spot sales		Network cost saving		Energy cost saving	
	TMY	2019 scaled	TMY	2019 scaled	TMY	2019 scaled	TMY	2019 scaled	TMY	2019 scaled
Auckland	350	350	5.02	5.07	3.9	0.4	131	138	590	590
Christchurch	330	330	3.19	2.73	6.9	0.5	96	66	468	475
Napier	360	360	3.05	3.04	24.9	8.7	11	13	567	580
Tauranga	330	330	6.45	6.37	4.0	0.3	259	259	533	530
Hamilton	300	300	3.53	3.26	2.0	0.1	59	48	485	482
Nelson	330	330	5.80	5.27	6.8	2.4	176	141	564	565
Wellington	330	330	2.61	2.66	8.8	0.7	46	44	481	493
Dunedin	340	340	1.06	0.41	6.4	0.9	73	37	382	389

The comparison in Table 27 shows little difference in the IRR, with the largest change being a 0.65 percentage point difference for Dunedin. With the exception of Auckland and Wellington, 2019 solar generation IRRs are all lower. Figure 14 shows the peak loads for the TMY and 2019 solar data respectively for the Nelson site – the site used in Section 3.7. These show less peak load reduction from the 2019 solar data than the TMY solar data. Table 27 shows that in most centres any reduction in IRR is usually accompanied by lower network cost savings, but little reduction, if any, in energy cost savings. Spot sales are also typically lower with the 2019 data, although they are already significantly lower than energy cost savings.

Given the relatively small differences resulting from the use of 2019 data instead of TMY data, and given the good reasons identified in Section 3.7 for using TMY data, this endorses the use of TMY data in this report. The comparison also gives further support to the observation that network cost savings are sensitive to the timing and coincidence of load and generation, and that it is network cost savings that largely influence IRR.



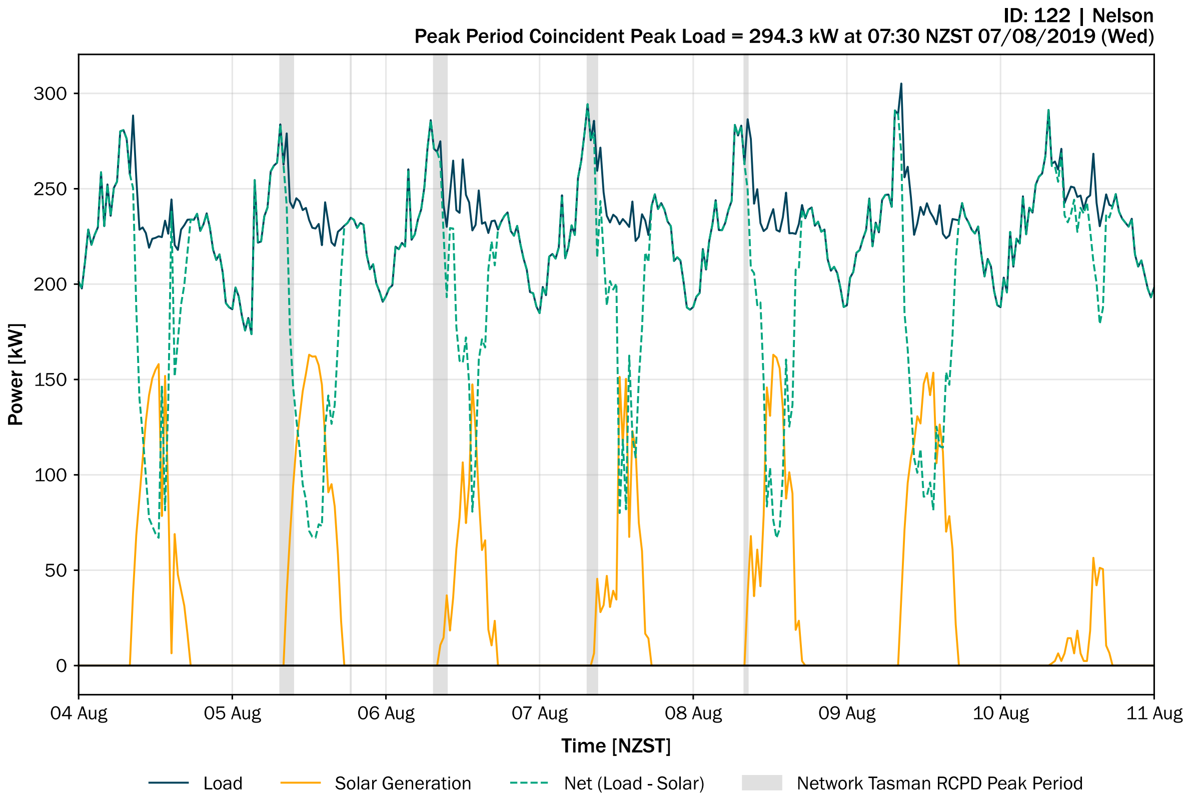


Figure 14: Peak load for the Nelson grocery retail site using TMY solar data (top) and 2019 solar data (bottom).

6 Conclusions

This report has presented and discussed case study results for eleven businesses with fifteen load types across eight New Zealand centres, comprising a total of 144 individual sites. It has found that it is difficult to definitively identify a particular business or load type likely to benefit from solar across the eight centres, or by characteristics of electricity consumption such as day-time to night-time load ratio or summer to winter consumption. However, it has identified that in many cases it is the network cost savings that determine the financial performance of commercial-scale solar, provided it is located in an area with suitable solar resource and wholesale prices.

Where these network cost savings do contribute to good financial performance, it is generally because of a coincidence of load, generation, and network pricing that strongly rewards demand reduction, often at peak times. The identification of this coincidence of factors requires a half-hourly analysis for a full year, and detailed modelling of network pricing structures, as was completed in this report. A key recommendation for businesses considering investing in solar is therefore that this type of analysis is required to accurately forecast financial returns.

The importance of network cost savings for a business investing in solar is also a key finding for electricity distributors. It means that, in the cases identified, existing network pricing structures may send a signal for businesses to invest in distributed solar generation, and so distributors should consider whether this leads to a commensurate reduction in the cost of providing a network service.

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8 Appendix One – Commercial solar capital cost review

The following studies were utilised in preparing the capital costs, with notes against each:

Fraunhofer Photovoltaics Report

Fraunhofer (16 September 2020) includes for the first time an analysis of price trends of PV rooftop systems from 10 kWp to 100 kWp as well as an update on price learning curves for modules. The capital cost given for 10 kWp to 100 kWp systems in Germany is 1.05 €/Wp for Q4 2019 calendar year, and the learning curve for modules as 75%.

Annualising the learning curve, using the formula and doubling rate of 3.68 years derived by Miller (2020), and using the annualised learning curve to project the 2019 Fraunhofer cost to 2021, gives an estimated cost in New Zealand currency, using an exchange rate of 0.59.[13] This is NZ 1.52 $/Wp for 10-100 kWp capacity rooftop solar systems.

National Renewable Energy Laboratory (NREL) Solar Industry Updates

In the NREL Q2/Q3 2020 Solar Industry Update, Feldman and Margolis (8 December 2020) give the capital cost of systems in the USA as summarised in the table below (only 10 - 500 kW systems are summarised, those being rooftop sizes in the range considered).

Table 28: NREL commercial rooftop solar capital cost summary.

System Capacity	Cost (US $/Wp-dc)		
	H2 2018	H2 2019	H2 2020
10 kW - 100 kW	3.54	3.54	3.47
100 kW - 500 kW	2.63	2.47	2.25

The capital costs above are the average from a number of states. The costs reported showed considerable variation between the states; dependent on state taxes, labour costs and transport costs.

Projecting the costs forward to 2021 using the Franuhofer learning curve (above), converting to New Zealand currency using an exchange rate of 0.716, but not removing any sales tax gives the following costs:

- Small systems (≤ 100 kW_{DC}): NZ $4.48 $/Wp-dc
- Large systems (> 100 kW_{DC}): NZ $2.91 $/Wp-dc

International Renewable Energy Agency (IRENA) Power Generation Costs

IRENA (2020, p. 68) gives a useful table of installed costs (US $/Wp) in a variety of countries, over time for commercial solar PV. This table has been converted to New Zealand currency using a USD/NZD exchange rate of 0.716, and the 2019 values projected forward to 2020 and 2021 using the learning curve derived from Fraunhofer above. It is given below for selected countries and USA states.

The disadvantage of the IRENA (2020) analysis is that it is not classified by capacity (kW), so presumably gives an average cost across a range of sizes.

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[13] This assumes the learning curve applies to all solar components, not just the modules. From Miller (2020) the learning curve for BOS components is similar to that of modules.

Table 29: IRENA commercial rooftop solar capital cost summary (NZ $/Wp), 2020 and 2021 projected.

Selected countries and USA states	Calendar year											
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Australia					3.97	3.10	2.73	2.34	2.18	2.04	1.89	1.75
China		4.46	3.48	2.96	2.32	1.96	1.79	1.71	1.31	1.06	0.98	0.91
Italy	7.55	6.44	3.63	2.87	2.82	2.19	2.01	1.83	1.65	1.59	1.47	1.36
Japan			7.32	5.88	4.36	3.38	3.29	3.17	2.90	2.77	2.56	2.37
Germany		4.88	3.16	2.69	2.36	1.77	1.89	1.80	1.76	1.58	1.46	1.35
United Kingdom							2.63	2.42	2.32	2.30	2.13	1.97
Arizona	9.82	8.68	7.65	6.06	4.99	5.36	4.80	4.34	3.75	3.46	3.20	2.96
California	9.07	8.75	6.94	6.47	5.12	4.98	5.16	4.90	4.47	4.30	3.98	3.68

Lawrence Berkeley National Laboratory (LBNL) Distributed Solar 2020 Data Update

This update (Barbose December 2020) specifically covers residential and non-residential rooftop systems, with ground mounted systems covered in a separate Utility-Scale edition. It includes, amongst other things, installed system prices and system sizing.

Findings show the median non-residential system size to be 40 kWp in 2019, but with a range from about 10 kWp to over 1 MWp – with the majority being below about 120 kWp. It also shows an increasing inverter loading ratio from around 1.0 in 2006 to a median between 1.17 (small non-residential) and 1.29 (large non-residential) in 2019.

Recent installed costs trends for small and medium non-residential systems are summarised below:

Table 30: LBNL commercial rooftop solar capital cost summary (2019 US $/Wp-dc).

Non-Residential System Capacity	Calendar year		
	2017	2018	2019
Small (≤ 100 kW_{DC})	3.3	3.1	3.1
Large (> 100 kW_{DC})	2.6	2.4	2.3

Fitting an exponential to the LBNL data from 2010 to 2019, and using the exponential to project forward to 2021 gives the following costs in US and New Zealand currency (using an exchange rate of 0.716):

- Small systems (≤ 100 kW_{DC}): 2.23 US $/Wp-dc, or NZ $3.11 $/Wp-dc
- Large systems (> 100 kW_{DC}): 1.64 US $/Wp-dc, or NZ $2.29 $/Wp-dc

Lazard Version 14.0 Levelized Cost of Energy Analysis (2020)

Lazard (2020) provide the broad range of total capital costs used in their LCOE determinations. For 1 MW commercial and industrial rooftop the low case used is 2.23 NZ $/Wp and the high case is $3.95 NZ $/Wp (using an exchange rate of 0.716).

Summary and costs used in this report

Combining the figures from the above sources gives the following summary.

Table 31: Summary of commercial rooftop solar capital costs (2021 NZ $/Wp).

<table>
<tr><th>Non-Residential System Capacity</th><th>Fraunhofer (Germany)</th><th>NREL (USA)</th><th>IRENA (Australia)</th><th>IRENA (Germany)</th><th>IRENA (AZ)</th><th>IRENA (CA)</th><th>LBNL</th><th>Lazard (lower)</th></tr>
<tr><td>Small (≤ 100 kW_{DC})</td><td>1.52</td><td>4.48</td><td rowspan="2">1.75</td><td rowspan="2">1.35</td><td rowspan="2">2.96</td><td rowspan="2">3.68</td><td>3.11</td><td></td></tr>
<tr><td>Large (> 100 kW_{DC})</td><td></td><td>2.91</td><td>2.29</td><td>2.23</td></tr>
</table>

It is clear that the system costs from the US are consistently higher than those from Germany and Australia (and from Table 29, higher than many other countries). We therefore discount the costs from the USA (assuming one of the reasons for the higher costs are taxes), but avoid costs as low as Australia and Germany, which are both highly established solar markets. We use figures of:

- 2.6 NZ $/Wp for 10 kWp systems (upper sensitivity of 3.12, lower sensitivity of 2.08, ±20%), which also roughly matches the 10 kWp system cost of residential installations in New Zealand;
- 2.3 NZ $/Wp for 100 kWp systems (upper sensitivity of 2.76, lower sensitivity of 1.84, ±20%), which is below the USA costs of systems of this size but above the costs in mature markets such as Germany and Australia;
- 1.8 NZ $/Wp for 500 kWp systems (upper sensitivity of 2.16, lower sensitivity of 1.44, ±20%);
- 1.7 NZ $/Wp for 1000 kWp systems (upper sensitivity of 2.04, lower sensitivity of 1.36, ±20%), which is below the USA costs and slightly below the 2021 cost of 1.79 NZ $/Wp used in the utility-scale study by Miller (2020), as the mounting requirements will be lower (ground mounting foundations of driven piles or concrete slabs will not be required, with the building providing the mounting structure); and
- Costs modelled with a piecewise linear function between these points.

In deriving the above costs, we assume an inverter loading ratio of 1.0 (as is used in this analysis) and therefore assume $/Wp-dc translates directly to $/Wp-ac.

9 Appendix Two – Contract retail electricity prices used

Contract retail prices used for the eight centres in this study follow on the next four pages.

All prices given have units of c/kWh. The Transpower grid exit points from which the nodal spot prices were obtained is given in brackets. Nodal spot prices were obtained from the Electricity Authority's EMI website.

Auckland - Calculated from 2014-2019 spot price average (OTA2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.33	6.96	9.32	10.28	9.26	8.17	6.27	6.37	7.37	7.35	8.07	7.32
February	7.09	8.57	11.77	12.23	10.75	9.14	6.39	6.44	8.29	7.80	8.21	7.82
March	7.56	9.25	11.63	11.87	10.80	9.35	7.09	7.25	9.28	8.64	8.85	8.36
April	6.91	7.75	10.53	10.16	11.44	9.29	6.68	6.35	8.76	8.03	9.21	7.96
May	7.69	8.43	12.57	10.87	13.12	10.65	7.60	6.62	9.71	9.73	10.95	9.06
June	8.16	9.12	14.79	11.51	14.20	11.67	8.18	7.20	10.15	9.51	10.58	8.92
July	7.93	8.31	14.38	11.06	11.91	10.69	8.12	7.68	9.38	9.11	9.94	9.16
August	7.22	7.82	12.09	9.35	13.44	10.42	7.79	7.08	8.96	8.57	9.33	9.56
September	6.77	7.19	9.76	8.61	9.08	8.40	6.51	6.20	7.58	6.89	7.25	7.27
October	6.23	8.11	9.69	8.61	8.21	7.67	6.07	6.76	8.15	6.99	6.81	7.56
November	4.78	6.24	7.58	7.58	6.83	5.93	4.99	5.57	7.31	6.42	6.89	6.17
December	5.36	6.42	8.42	8.63	7.91	6.82	4.61	5.33	6.83	6.61	6.78	6.18

Hamilton - Calculated from 2014-2019 spot price average (HLY2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.24	6.87	9.16	10.10	9.14	8.07	6.18	6.29	7.29	7.27	7.99	7.22
February	6.99	8.45	11.52	11.97	10.58	9.01	6.30	6.36	8.18	7.69	8.11	7.71
March	7.47	9.14	11.46	11.68	10.65	9.23	7.00	7.17	9.16	8.54	8.75	8.25
April	6.82	7.65	10.46	10.01	11.28	9.17	6.57	6.26	8.62	7.91	9.08	7.84
May	7.56	8.29	12.31	10.66	12.85	10.45	7.46	6.50	9.54	9.56	10.76	8.90
June	8.03	8.96	14.42	11.26	13.85	11.40	8.04	7.08	9.96	9.34	10.36	8.76
July	7.80	8.18	14.03	10.83	11.62	10.45	7.98	7.55	9.21	8.95	9.73	8.99
August	7.10	7.69	11.78	9.14	13.07	10.15	7.66	6.96	8.80	8.42	9.15	9.35
September	6.66	7.07	9.53	8.43	8.88	8.21	6.40	6.11	7.46	6.78	7.13	7.13
October	6.11	7.95	9.44	8.41	8.02	7.50	5.96	6.63	7.96	6.84	6.66	7.39
November	4.67	6.12	7.44	7.44	6.71	5.82	4.88	5.46	7.18	6.30	6.77	6.05
December	5.27	6.32	8.26	8.46	7.79	6.72	4.53	5.24	6.74	6.52	6.70	6.08

Tauranga - Calculated from 2014-2019 spot price average (TGA0331)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.20	6.79	8.95	9.86	8.95	7.99	6.13	6.21	7.16	7.16	7.85	7.14
February	6.91	8.33	11.28	11.71	10.37	8.92	6.24	6.28	8.02	7.55	7.96	7.62
March	7.42	9.06	11.27	11.48	10.50	9.19	6.95	7.10	9.03	8.42	8.63	8.18
April	6.76	7.58	10.23	9.85	11.14	9.12	6.50	6.18	8.47	7.79	8.93	7.74
May	7.47	8.20	12.10	10.46	12.66	10.32	7.36	6.39	9.36	9.40	10.56	8.77
June	7.96	8.87	14.09	11.07	13.63	11.23	7.98	7.02	9.76	9.14	10.19	8.63
July	7.71	8.08	13.75	10.63	11.47	10.31	7.89	7.47	9.01	8.77	9.55	8.82
August	6.99	7.56	11.51	8.93	12.78	9.94	7.54	6.86	8.57	8.24	8.94	9.13
September	6.57	6.96	9.29	8.25	8.69	8.06	6.31	6.01	7.28	6.64	6.97	7.00
October	6.01	7.78	9.21	8.23	7.85	7.38	5.86	6.50	7.77	6.70	6.51	7.23
November	4.58	5.98	7.22	7.25	6.53	5.72	4.78	5.31	6.96	6.14	6.60	5.91
December	5.21	6.20	7.98	8.19	7.57	6.62	4.48	5.15	6.56	6.37	6.53	5.97

Napier - Calculated from 2014-2019 spot price average (RDF2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.12	6.72	8.89	9.79	8.88	7.90	6.04	6.14	7.12	7.12	7.81	7.07
February	6.83	8.25	11.15	11.60	10.26	8.83	6.16	6.20	7.94	7.49	7.90	7.54
March	7.32	8.96	11.21	11.43	10.42	9.08	6.86	7.01	8.95	8.35	8.56	8.10
April	6.67	7.48	10.14	9.76	10.98	8.97	6.40	6.08	8.36	7.70	8.82	7.63
May	7.32	8.04	11.92	10.31	12.42	10.14	7.20	6.26	9.23	9.28	10.38	8.61
June	7.81	8.69	13.85	10.79	13.27	10.95	7.83	6.85	9.55	8.99	9.97	8.44
July	7.60	7.97	13.48	10.51	11.21	10.08	7.77	7.35	8.91	8.68	9.39	8.68
August	6.90	7.46	11.33	8.83	12.53	9.77	7.44	6.76	9.79	8.14	8.79	9.00
September	6.49	6.88	9.21	8.19	8.59	7.96	6.23	5.93	7.21	6.57	6.89	6.91
October	5.93	7.68	9.11	8.14	7.75	7.27	5.78	6.40	7.68	6.63	6.43	7.13
November	4.52	5.91	7.17	7.21	6.49	5.66	4.72	5.25	6.89	6.08	6.53	5.84
December	5.15	6.15	7.99	8.21	7.56	6.56	4.42	5.09	6.53	6.34	6.51	5.91

Wellington - Calculated from 2014-2019 spot price average (HAY2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.30	6.77	8.58	9.40	8.55	7.81	6.24	6.25	7.00	7.00	7.65	7.05
February	6.91	8.09	10.56	10.90	9.69	8.58	6.21	6.19	7.67	7.25	7.60	7.37
March	7.57	8.97	10.78	10.93	9.98	9.02	7.08	7.15	8.72	8.17	8.34	8.07
April	6.91	7.61	9.89	9.49	10.64	8.92	6.63	6.26	8.26	7.60	8.68	7.60
May	7.38	7.95	11.22	9.73	11.68	9.69	7.28	6.31	8.94	8.99	10.04	8.42
June	7.94	8.71	13.34	10.44	12.75	10.62	7.94	6.97	9.34	8.75	9.58	8.21
July	7.86	8.13	13.23	10.53	11.12	10.05	8.04	7.60	8.84	8.68	9.25	8.59
August	7.12	7.57	10.98	8.59	12.11	9.59	7.70	6.95	8.37	8.07	8.61	8.92
September	6.86	7.12	9.01	8.08	8.39	7.92	6.59	6.22	7.29	6.69	6.93	7.01
October	6.24	7.82	9.00	8.08	7.67	7.36	6.05	6.61	7.66	6.64	6.42	7.26
November	4.57	5.77	6.74	6.75	6.09	5.47	4.79	5.26	6.72	5.91	6.32	5.75
December	5.30	6.13	7.66	7.83	7.26	6.49	4.54	5.13	6.29	6.16	6.32	5.85

Nelson - Calculated from 2014-2019 spot price average (STK2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.81	7.24	9.29	10.12	9.42	8.40	6.72	6.56	7.32	7.33	8.05	7.69
February	7.34	8.60	11.07	11.39	10.17	9.09	6.60	6.46	8.02	7.53	8.10	7.80
March	8.19	9.63	11.42	11.44	10.52	9.69	7.62	7.63	9.09	8.55	8.76	8.61
April	7.62	8.24	10.73	10.11	10.82	9.67	7.30	6.79	8.78	8.01	9.08	8.20
May	7.94	8.44	11.96	10.04	11.83	10.03	7.49	6.37	8.57	8.21	9.46	8.41
June	8.58	9.34	14.43	11.10	13.16	11.26	8.56	7.50	10.04	9.23	9.93	8.69
July	8.56	8.86	12.87	11.42	11.93	11.24	8.76	8.23	9.36	8.95	9.68	9.20
August	7.73	8.19	11.96	9.13	12.71	10.37	8.35	7.51	8.95	8.53	9.12	9.46
September	7.53	7.82	9.89	8.74	9.05	8.61	7.22	6.80	7.94	7.23	7.49	7.62
October	6.81	8.52	9.86	8.82	8.30	8.01	6.59	7.21	8.31	7.09	6.79	7.86
November	4.85	6.00	6.91	6.76	6.36	5.70	4.49	4.74	5.51	4.91	5.09	4.88
December	5.65	6.49	8.05	7.98	7.50	6.91	5.06	5.43	6.42	6.21	6.66	6.18

Christchurch - Calculated from 2014-2019 spot price average (ISL2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.63	7.01	8.91	9.74	9.06	8.07	6.53	6.36	7.03	7.06	7.74	7.39
February	7.15	8.32	10.64	10.96	9.78	8.76	6.43	6.28	7.72	7.27	7.80	7.53
March	7.94	9.28	10.94	10.98	10.09	9.31	7.39	7.37	8.72	8.23	8.41	8.27
April	7.37	7.93	10.17	9.64	10.28	9.23	7.08	6.58	8.36	7.66	8.66	7.83
May	7.68	8.16	11.32	9.56	11.23	9.56	7.26	6.17	8.15	7.87	9.01	8.03
June	8.32	9.03	13.64	10.56	12.48	10.70	8.32	7.30	9.57	8.88	9.48	8.31
July	8.32	8.59	12.17	10.88	11.34	10.71	8.50	8.01	8.93	8.62	9.26	8.81
August	7.53	7.95	11.34	8.73	12.15	9.91	8.13	7.33	8.54	8.25	8.75	9.08
September	7.32	7.57	9.37	8.35	8.63	8.23	7.05	6.63	7.58	6.99	7.18	7.30
October	6.65	8.21	9.37	8.45	7.93	7.69	6.43	6.97	7.91	6.85	6.50	7.54
November	4.73	5.77	6.58	6.46	6.09	5.48	4.39	4.60	5.26	4.72	4.86	4.70
December	5.53	6.28	7.68	7.64	7.18	6.66	4.96	5.30	6.15	5.99	6.40	5.97

Dunedin - Calculated from 2014-2019 spot price average (HWB2201)												
Month	Weekdays						Non weekdays					
	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359	0000 to 0359	0400 to 0759	0800 to 1159	1200 to 1559	1600 to 1959	2000 to 2359
January	6.50	6.78	8.19	8.97	8.24	7.67	6.38	6.17	6.57	6.67	7.26	7.07
February	6.80	7.70	9.36	9.64	8.63	8.01	6.30	6.19	7.18	6.79	7.25	7.12
March	7.82	8.86	10.11	10.24	9.39	8.89	7.26	7.26	8.25	7.95	8.12	8.00
April	7.24	7.72	9.53	9.14	9.66	8.80	6.90	6.43	7.96	7.32	8.25	7.53
May	7.31	7.73	10.13	8.85	10.23	8.80	6.92	5.89	7.57	7.34	8.33	7.49
June	7.89	8.50	12.33	9.76	11.29	9.77	7.91	6.96	8.86	8.31	8.78	7.74
July	7.96	8.17	11.08	10.21	10.41	9.91	8.13	7.69	8.35	8.16	8.61	8.26
August	7.18	7.51	10.20	8.08	11.05	9.08	7.78	7.02	7.95	7.71	8.11	8.46
September	7.20	7.34	8.58	7.93	8.05	7.72	6.95	6.51	7.23	6.73	6.83	6.97
October	6.28	7.57	8.36	7.69	7.21	7.08	6.03	6.47	7.10	6.17	5.89	6.90
November	4.50	5.30	5.88	5.81	5.42	5.05	4.18	4.34	4.83	4.33	4.47	4.37
December	5.31	5.90	6.98	6.83	6.42	6.19	4.76	5.04	5.70	5.56	5.84	5.54

10 Appendix Three – Electricity distributor pricing summaries

This appendix documents the network pricing used in the study.

10.1 Vector

EDB: Vector (Auckland Network)

Reference: Vector (1 April 2020)

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution					Transmission				
						Transformer Capacity[1] ($/kVA/day)	Nominated Maximum Capacity[1] ($/kVA/day) (CAPY)	Metered Maximum Demand[6] ($/kVA/day)	Peak Charge[9] ($/kVA/day) (DAMD[8])	Volume ($/kWh)[5] Anytime (24UC)	Transformer Capacity[1] ($/kVA/day)	Nominated Maximum Demand[1] ($/kVA/day)	Metered Maximum Demand[6] ($/kVA/day)	Peak Charge[9] ($/kVA/day) (DAMD[8])	Volume ($/kWh)[5] Anytime (24UC)
Auckland (Vector)	Low Voltage	Low Voltage	1,479 (+3,393)	10	70		0.0421		0.2917	0.0120				0.1900	
	Transformer	Transformer	937 (+585)	70	3,000		0.0412		0.2858	0.0117				0.1900	
	High Voltage	High Voltage	143 (+32)	10,000	100,000		0.0399		0.2772	0.0113				0.1900	

Notes:

(1) Fixed charges not included as they will not vary with and without solar. Likewise, neither Transformer Capacity nor Nominated Maximum Demand for major customers are considered reducible by retro-fitted solar, as they determine the size of the assets required to supply the customer.

(2) The re-classification from one category to another from solar potentially reducing load is not considered.

(5) For volume charges in all customer categories the 24 uncontrolled (24UC) anytime period is used to determine kWh reduction by solar, as most connections are on this and it is slightly more conservative in valuing the benefit of solar from solar's offsetting of day kWh usage.

(6) Metered maximum anytime demand is not used by Vector.

(8) DAMD is 8am and 8pm on weekdays (including public holidays).

(9) The daily DAMD price is applied to the average of the customer's ten highest kVA demands during DAMDs each month. This gives an average peak demand per month, with the charge calculated by multiplying this by the DAMD price and the number of days in the month. The result is summed across all months.

(10) Power factor charge (PWRF) is not included, as the improvement or degradation of power factor is unknown but may be able to be adjusted to optimise solar.

(12) Excess demand charges, or potential reduction by solar, are not considered.

(13) Distributed generation export prices are zero.

10.2 WEL Networks

EDB: WEL Networks

Reference: WEL Networks (1 April 2020)

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution							Transmission[4]						
						Daily Fixed[1] ($/day)	Capacity[6] ($/kVA/day)	Peak Charge[9] ($/kVA/month)	Volume ($/kWh)				Daily Fixed[1] ($/day)	Capacity[6] ($/kVA/day)	Peak Charge[9] ($/kW/day)	Volume ($/kWh)			
									Peak	Shoulder	Off-Peak	Uncontrolled				Summer Day	Summer Night	Winter Day	Winter Night
Hamilton (WEL Networks)	General	Small Commercial	9,896		110	N/A			0.1333	0.0807	0.0530		N/A						
	Low Voltage 400V	Commercial	697	110	500	N/A	$0.0920	PDS: 12.5303 PDW: 18.9782				0.0032	N/A						
	Medium Voltage 11kV	Large Commercial	174	500	2,500	N/A	$0.0920	PDS: 10.9730 PDW: 16.6871				0.0026	N/A						
	High Voltage 33kV	Special	2	2,500		N/A	$0.0920	PDS: 9.9594 PDW: 15.1903				0.0023	N/A						

Notes:

(1) Fixed charges not included as they will not vary with and without solar. Likewise, Nominated Maximum Demand for major customers is not considered reducible by retro-fitted solar, as it determines the size of the assets required to supply the customer and is therefore a fixed cost.

(2) Similar to the above, the re-classification from one category to another from solar potentially reducing load is not considered.

(4) All transmission charges are based on 25% of distribution charges (Note ii of the WEL Networks Pricing Schedule.)

(6) Max demand is nominated but can be changed once per year. Therefore, we treat it as metered and assess the reduction brought about by solar, based on anytime metered demand.

(9) Peak Demand is determined from the average of the six highest half-hourly demands which are coincident with WEL's published peak periods in each month. Peak periods are workdays 07:00 - 09:30 and 17:30 - 20:00. The Peak Demand Summer Price (PDS) applies in summer months (1 October to 30 April inclusive) and the Peak Demand Winter Price (PDW) applies in winter months (1 May to 30 September inclusive).

(10) Power factor charge is not included, as the improvement or degradation of power factor is unknown but may be able to be adjusted to optimise solar.

(12) Excess demand charges, or potential reduction by solar, are not considered (it should be noted that this presents a risk if solar does not provide the demand reduction nominated per Note 6).

(13) Distributed generation export prices are zero.

10.3 Powerco

EDB: Powerco (Eastern, Tauranga price zone)

Reference: Power a (1 April 2020) and Power b (1 April 2020)

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution					Transmission[4]				
						Daily Charge[1] ($/day)	Metered Maximum Demand[6]	Peak Charge[9]	Volume ($/kWh)[5]		Daily Charge[1] ($/day)	Metered Maximum Demand[6] ($/kVA/day)	Peak Charge[9] ($/kW/day)	Volume ($/kWh)	
									Peak	Off-Peak				Peak	Off-Peak
Tauranga (Powerco Eastern)	T06/T06S General Commercial	Small Commercial (up to 41 kW)			41	N/A	$0.0000	0.0000	0.1339	0.0349	N/A				
	T22/V24 Medium Commercial	Commercial (up to 173 kW)		42	173	N/A	$0.0000	0.0000	0.0634	0.0634	N/A				
	T24/T41/V28 Medium Commercial	Medium Commercial (200-299 kW)		200	299	N/A	$0.0000	0.0000	0.0463	0.0463	N/A				
	T50/V40 Large Commercial	Large Commercial		300	1,499	N/A	$0.0000	0.0000	0.0000	0.0000	N/A				
	T60/V60 Large Commercial/Industrial	Very Large Commercial/Industrial				N/A	$0.0000	0.0000	0.0000	0.0000	N/A				

Notes:

(1) Fixed charges not included as they will not vary with and without solar. Likewise, Nominated Maximum Demand for major customers is not considered reducible by retro-fitted solar, as it determines the size of the assets required to supply the customer and is therefore a fixed cost.

(2) Similar to the above, the re-classification from one category to another from solar potentially reducing load, and any cost savings from this, is not considered. However, the category is re-assigned based on the maximum load with solar, to potentially bring it into a category where cost savings from the variable rates that apply in peak and/or off-peak periods may provide a higher cost saving. This is on the basis that maximum demand may be nominated and changed once a year. It was also to provide some indication of cost saving in the absence of peak charges and time-of-use volume charges for customers larger than 'General Commercial'.

(4) All transmission charges are based on 33%, 5% or 6% of distribution charges depending on the category.

(5) In all cases TOU uncontrolled prices are used. The TOU Peak is weekdays (mon-fri including public holidays) 7:00am-11:00am and 5:00pm-9:00pm, while the TOU Off-Peak is weekdays 11:00am-5:00pm and 9:00pm to 7:00am and weekends all day and night.

(6) Powerco does not have anytime peak charges.

(9) Powerco does not have peak demand charges.

(10) Power factor charge is not included, as the improvement or degradation of power factor is unknown but may be able to be adjusted to optimise solar.

(12) Excess demand charges, or potential reduction by solar, are not considered.

(13) Distributed generation export prices are zero.

10.4 Unison

EDB: Unison (Hawke's Bay Network)

Reference: Unison (6 March 2020)

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution					Transmission[4]			
						Fixed Charge ($/day)[1]	Nominated Maximum Demand[1] ($/kVA/day)	Anytime (Metered) Maximum Demand[6] ($/kW/month)	Peak Charge[9] ($/kW/month)	Volume ($/kWh)[5]	Nominated Maximum Demand[1] ($/kVA/day)	Metered Maximum Demand ($/kVA/day)	Peak Charge ($/kW/day)	Volume ($/kWh)
										Anytime 24 hr UC				Anytime 24 hr UC
Hawkes Bay (Unison)	Small Commercial (MC1 & MC2)	Small Commercial	3,360	14	138	N/A		$2.55	SOPD: $3.5 WOPD: $7.0	0.0480				
	Large Commercial (MC3, MC5-MC9, MC4 replaced by MC5-MC9)	Large Commercial	360	139	1,039	N/A		$2.55	SOPD: $3.5 WOPD: $7.0					

Notes:

(1) Fixed charges not included as they will not vary with and without solar. Likewise, Nominated Maximum Demand for major customers is not considered reducible by retro-fitted solar, as it determines the size of the assets required to supply the customer and is therefore a fixed cost.

(2) Similar to the above, the re-classification from one category to another from solar potentially reducing load is not considered.

(4) All transmission charges are based on 25.4% of distribution charges (Note 9 of the Unison Electricity Distribution Delivery Prices Schedule, Hawke's Bay Region.)

(5) For volume charges in the Small Commercial (MC1 & 2) category the anytime uncontrolled price is used, as most connections are on this and it is slightly more conservative in valuing the benefit of solar from solar's offsetting of day kWh usage. NB: There is no variable $/kWh charge for the Large Commercial category.

(6) Anytime (Metered) maximum anytime demand charge (DMND): Unison uses the single highest demand in a month, rather than year, with no restriction on time period (Note 5 of the Unison Electricity Distribution Delivery Prices Schedule, Hawke's Bay Region.)

(9) Peak Demand (SOPD and WOPD) relates to kW's delivered over the half hour period of maximum demand between the hours of 7am and 11am, and, 5pm and 9pm on a working day. It is determined from the single highest half hour demand in each month. The SPOD rate applies in summer (1 October to 30 April inclusive) and the WOPD rate applies in winter (1 May to 30 September inclusive).

(10) Power factor charge is not included, as the improvement or degradation of power factor is unknown but may be able to be adjusted to optimise solar.

(12) Excess demand charges, or potential reduction by solar, are not considered.

(13) Distributed generation export prices are zero.

10.5 Wellington Electricity

EDB: Wellington Electricity

Reference: Wellington Electricity a (26 February 2020) and Wellington Electricity b (12 February 2020)

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution				Transmission[4]			
						Fixed / connection, dayCost ($/connection/day)[1]	Metered Maximum Demand[6] ($/kVA/day)	Peak Charge[9]	Volume ($/kWh)[5] 24 hour uncontrolled	Fixed / connection, dayCost ($/connection/day)[1]	Metered Maximum	Peak Charge ($/kW/day)	Volume ($/kWh)
Wellington (Wellington Electricity)	General LV Under 69kVA	General LV Under 69kVA	9,886		69	N/A	$0.0000	0.0000	0.0328	N/A			
	General TF Under 138kVA	General TF Under 138kVA	414	70	138	N/A	$0.0000	0.0000	0.0389	N/A			
	General TF Under 300kVA	General TF Under 300kVA	342	138	300	N/A	$0.0000	0.0000	0.0161	N/A			
	General TF Under 1500kVA	General TF Under 1500kVA	203	300	1,500	N/A	$0.0140	5.3718 $/kVA/month	0.0058	N/A			
	General TF Over 1500kVA	General TF Over 1500kVA	33	1,500		N/A	$0.0247	10.1211 $/kW/month	0.0013	N/A			

Notes:

(1) Fixed charges are not included as they will not vary with and without solar, by retro-fitted solar, as it determines the size of the assets required to supply the customer and is therefore a fixed cost.

(2) The re-classification from one category to another from solar potentially reducing load is not considered.

(4) All transmission charges are based on 25% of distribution charges.

(5) All volumes are 24 hour uncontrolled as published.

(6) Max demand is nominated but can be changed once per year. Therefore, we treat it as metered and assess the reduction brought about by solar, based on anytime metered demand. This is based on the single highest kVA demand occuring at anytime in a year.

(9) Peak Demand is determined from the single highest half-hourly kVA demand in each month in the 300-1500kVA category and the single highest kW demand in each month coincident with WELL's published peak periods in each month in the over 1500kVA category. Peak periods are workdays 07:30 - 09:30 and 17:30 - 19:30 on weekdays (including public holidays).

(10) Power factor charge is not included, as the improvement or degradation of power factor is unknown but may be able to be adjusted to optimise solar.

(12) Excess demand charges, or potential reduction by solar, are not considered (it should be noted that this presents a risk if solar does not provide the demand reduction nominated per Note 6).

(13) Distributed generation export prices are zero.

10.6 Network Tasman

EDB: Network Tasman

Reference: Network Tasman (1 April 2020)

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution[3]							Transmission[4]						
						Fixed Charge ($/day)[1]	Metered Maximum Demand ($/kVA/day)[6,7]	Peak Charge[9] ($/kW/day)	Volume ($/kWh)[5]				Fixed Charge ($/day)[1]	Metered Maximum Demand ($/kVA/day)[6,7]	Peak Charge[9] ($/kW/day)	Volume ($/kWh)[5]			
									Summer Day	Summer Night	Winter Day	Winter Night				Summer Day	Summer Night	Winter Day	Winter Night
Nelson/ Tasman (Network Tasman)	General (20-150 kVA) Cat 2	General	2,334	20	150	N/A	0.063		0.0264	0.0264	0.0264	0.0264	N/A	0.017		0.0151	0.0151	0.0151	0.0151
	Large Commercial >= 150 kVA TOU Cat 3.4	Large Commercial	166	150	10,000	N/A	0.1225	0.0356	0.0095	0.0051	0.0245	0.0051	N/A	0.0312	0.257				
	Category 3.1, 3.3, 3.5 not considered																		
	Individually prices categories not considered																		

Notes:

(1) Fixed costs (the Fixed Charge ($/day)) are not considered, as solar does not change them.

(2) The re-classification from one category to another from solar potentially reducing load is not considered.

(3) Any discount has been subtracted from the distribution price.

(4) Pass through has been added to the transmission price.

(5) For volume charges in the General Category (Cat 2) the uncontrolled price is used, as most connections are on this and it is slightly more conservative in valuing the benefit of solar from solar's offsetting of day kWh usage.

(6) The daily capacity price is assumed to be based on anytime metered demand in both General and Large categories. Therefore, the cost of this is considered in terms of any reduction in maximum demand brought about by solar.

(7) In both General and Large connections the Daily Capacity Price and Anytime kVA Demand price are both applied to the single highest kVA demand in the year (regulatory although calendar year used in the model).

(8) Summer is defined as October to April inclusive; Winter is defined as May to September inclusive; Day is 07:00-23:00; Night is 23:00-07:00.

(9) The Peak Charge is the RCPD kW Demand charge, and is applied to all of a customer's half-hourly loads coincident with Upper South Island RCPD periods. These coincident half-hourly loads are then averaged to give a single peak load for each customer. The daily price ($/kW/day) is then applied to this. Upper South Island RCPD periods for 2019 were supplied by Transpower.

(10) Low power factor charge is not included, as the improvement or degradation of power factor is unknown. Solar inverters may be able to be adjusted to optimise solar, however this is unclear.

(13) Distributed generation export prices are zero.

10.7 Orion

EDB: Orion

Reference: Orion a (31 January 2020) and Orion b (24 February 2020)

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution							Transmission						
						Capacity Charge[11] ($/kW/day)	Transformer Capacity[1] ($/kVA/day)	Nominated Maximum Demand[1] ($/kVA/day)	Metered Maximum Demand[6] ($/kVA/day)	Peak Charge[9] ($/kW/day)	Volume ($/kWh)[8]		Capacity Charge[11] ($/kW/day)	Transformer Capacity[1] ($/kVA/day	Nominated Maximum Demand[1] ($/kVA/day)	Metered Maximum Demand[6] ($/kVA/day)	Peak Charge[9] ($/kW/day)	Volume ($/kWh)[8]	
											Weekdays	Nights & Weekends						Weekdays	Nights & Weekends
Christchurch (Orion)	General Connection	General	204,239	20	300					0.2580	0.05119	0.01456					0.1540	0.01588	0.00342
	Major Customer Connection	Major	495	300	10,000		0.0119	0.0964		0.2382					0.008	0.0762	0.1573		
	Large Capacity Connection	Special	15	10,000	100,000														
	Irrigation	Irrigation	1,038			0.3846					0.05119	0.01456	0.0644					0.01588	0.00342

Notes:

(1) Fixed charges not included as they will not vary with and without solar. Likewise, neither Transformer Capacity nor Nominated Maximum Demand for major customers are considered reducible by retro-fitted solar, as they determine the size of the assets required to supply the customer.

(2) The re-classification from one category to another from solar potentially reducing load is not considered.

(5) For volume charges in the General Category the time-of-use categories are used to determine kWh reduction by solar, as there is alternative (see 8 for the definition of these).

(6) Metered maximum demand cost is determined using the greatest of (1) the average of the 12 highest half-hourly kVA demand during weekdays; (2) half of the average of the 12 highest half-hours kVA demands anytime in a year; and (3) 300 kVA.

(8) Day is defined as the time between 7am and 9pm (between half-hours ending 0730 and 2100). This makes Night between half-hours ending 2130 and 0700.

(9) Peak period: Chargeable peak demands measured over the winter period (May to August) when total network demand is highest. For General connections this is during the 100-150 hours given by Orion Chargeable Peak periods, and for Major connections this is during the 80-100 hours given by the Orion Control periods. The charge is applied to all loads coincident with these periods, averaged to give a single peak load. The daily price ($/kW/day) is then applied to this. Note, demand in General category is $/kW/day and demand in Major category is $/kVA/day. Orion Chargeable Peak Periods and Orion Control Periods were downloaded from Orion's website.

(10) Low power factor charge is not included, as the improvement or degradation of power factor is unknown. Solar inverters may be able to be adjusted to optimise solar, however this is unclear.

(11) Applies to irrigation only and is applied from 1 October to 31 March only. Not considered in this model as irrigation loads are not considered.

(13) Distributed generation export prices as given by Orion are implemented.

10.8 Aurora Energy

EDB: Aurora (Dunedin Network)

Reference: Aurora Energy Electricity Information Disclosure, Line charges effective 1 April 2020

Other: Prices are from 1 April 2020 and exclude GST

Centre (EDB) Used in Model	Category	Category Used in Model	Number of Connections	Min kVA	Max kVA	Distribution				Transmission[4]			
						Fixed Charge[1] ($/day)	Metered Maximum Demand[6,7] ($/kVA/day)	Peak Charge[9] ($/kW/day)	Volume ($/kWh)[5]	Fixed Charge[1] ($/day)	Metered Maximum Demand[6,7] ($/kVA/day)	Peak Charge[9] ($/kW/day)	Volume ($/kWh)
													Anytime 24 hr UC
Dunedin (Aurora Energy)	16 – 149 kVA Group 2	Group2	3,108	16	149	N/A	$0.0466	0.6186		N/A			
	150 – 249 kVA Group 3	Group3	103	150	249	N/A	$0.0763	0.4957		N/A			
	250 – 499 kVA Group 3	Group3a	91	250	499	N/A	$0.0673	0.4957		N/A			
	500 – 2499 kVA Group 4	Group4	73	500	2,499	N/A	$0.0466	0.4565		N/A			
	2500+ kVA Group 5	Group5	7	2500	10,000	N/A	$0.0267	0.3768		N/A			

Notes:

(1) Fixed costs (Daily Capacity Charge) are not considered, as solar does not change them.

(2) The re-classification from one category to another from solar potentially reducing load is not considered.

(4) All transmission charges are based on 29% of distribution charges (Note in the Aurora Energy Electricity Price Disclosure 2020).

(5) Aurora do not use volume charges; they use a distance price ($/kVA-km). Since solar does not change the distance this is not implemented.

(6) The Daily Capacity Price (titled Metered Maximum Demand in the table) is assumed to be based on anytime metered demand in all categories. Therefore, the cost of this is considered in terms of any reduction in maximum demand brought about by solar.

(7) In all categories the Daily Capacity Price (called Metered Maximum Demand in the above table) is applied to the single highest kVA demand in the year (regulatory although calendar year used in the model).

(9) The Peak Charge is the Aurora Energy Control Period kW Demand charge. The charge is determined using all loads coincident with Aurora Energy Control Periods, averaged to give a single peak load. The daily price ($/kW/day) is then applied to this. The Aurora Energy Halfway Bush control periods are used (South Dunedin Control Periods are not used). These were obtained from Aurora Energy.

(10) Low power factor charge is not included, as the improvement or degradation of power factor is unknown. Solar inverters may be able to be adjusted to optimise solar, however this is unclear.

(13) Distributed generation export prices are zero.

10.9 Additional network pricing notes

- Potential distribution loss factor changes (either up or down) are not considered. This is a potential cost or value stream not captured in this analysis.
- Potential changes to spot price location factors are not considered - essentially each individual customer is considered too small to influence these on their own. However, in aggregate they may reduce location factors. This is a value stream not captured in this analysis.
- Cost savings, or potentially cost increases, through changes to power factor (and costs resulting from power factor charges) are not considered. Potentially solar may be used to correct power factor to close to unity to reduce power factor charges. It is not considered because it would require specific set up and control of the PV inverters, and whether this capability exists in the particular inverters is unknown.
- TOU tariffs are used in all cases where possible; where is no time of use metering and/or a customer is not on a time of use tariff, benefits of solar cannot be assessed,
- All EDBs have DG export charges listed in their pricing disclosures, which are currently set at zero. These may increase in the future.

11 Appendix Four – Sites considered in the study

This appendix documents the load statistics for all of the sites in the study. Data is ordered by load type, location, and mean load.

ID	Load type	Centre	Load (kW)					
			Mean	Standard deviation	25th Percentile	50th Percentile	75th Percentile	Maximum
109	Big box retail	Auckland	148	44	106	149	171	316
69	Big box retail	Auckland	131	49	87	128	168	277
6	Big box retail	Auckland	118	33	95	111	137	242
10	Big box retail	Auckland	109	45	78	106	135	256
82	Big box retail	Auckland	96	47	65	87	122	244
78	Big box retail	Auckland	95	30	70	88	103	191
74	Big box retail	Auckland	93	42	75	95	116	254
1	Big box retail	Auckland	92	46	58	90	107	242
81	Big box retail	Auckland	92	46	63	91	117	221
84	Big box retail	Auckland	87	34	74	87	108	179
71	Big box retail	Auckland	84	30	66	84	101	197
83	Big box retail	Auckland	77	33	58	74	95	187
76	Big box retail	Auckland	77	28	59	80	89	161
5	Big box retail	Auckland	71	21	63	73	82	118
75	Big box retail	Auckland	62	25	45	66	77	173
2	Big box retail	Auckland	52	25	35	46	66	132
77	Big box retail	Auckland	50	33	10	54	72	142
80	Big box retail	Auckland	42	24	27	36	58	123
70	Big box retail	Auckland	38	18	27	38	48	101
88	Big box retail	Auckland	31	25	7	30	52	84
89	Big box retail	Auckland	27	18	9	25	44	70
91	Big box retail	Auckland	21	8	15	21	27	40
98	Big box retail	Auckland	16	14	4	6	26	59
101	Big box retail	Auckland	15	12	4	12	27	43
106	Big box retail	Auckland	13	12	3	4	24	45
102	Big box retail	Auckland	13	13	2	4	25	57
90	Big box retail	Auckland	11	9	3	4	21	26
86	Big box retail	Christchurch	151	36	124	147	171	280
13	Big box retail	Christchurch	133	30	119	130	150	260
11	Big box retail	Christchurch	88	35	70	93	112	196
63	Big box retail	Christchurch	84	34	68	87	106	189
64	Big box retail	Christchurch	75	33	53	78	98	177
59	Big box retail	Christchurch	67	42	33	76	99	170

ID	Load type	Centre	Load (kW)					
			Mean	Standard deviation	25th Percentile	50th Percentile	75th Percentile	Maximum
116	Big box retail	Christchurch	62	33	37	68	85	153
12	Big box retail	Christchurch	61	33	32	63	86	180
17	Big box retail	Christchurch	54	25	37	58	69	126
96	Big box retail	Christchurch	32	18	16	22	50	74
93	Big box retail	Christchurch	22	19	5	9	41	75
66	Big box retail	Dunedin	137	38	104	145	162	322
18	Big box retail	Dunedin	91	38	63	96	120	195
19	Big box retail	Dunedin	33	19	16	34	48	91
94	Big box retail	Dunedin	16	9	6	18	20	64
68	Big box retail	Hamilton	131	64	86	116	162	337
29	Big box retail	Hamilton	109	62	60	95	146	261
46	Big box retail	Hamilton	98	52	84	106	127	214
100	Big box retail	Hamilton	13	13	2	6	23	50
107	Big box retail	Hamilton	11	13	2	2	15	50
37	Big box retail	Napier	89	43	53	84	119	221
38	Big box retail	Napier	77	31	53	72	95	184
115	Big box retail	Napier	70	57	9	77	102	196
15	Big box retail	Nelson	105	46	75	103	135	232
65	Big box retail	Nelson	75	43	35	81	105	172
85	Big box retail	Nelson	50	26	32	57	63	143
95	Big box retail	Nelson	12	12	3	3	23	48
48	Big box retail	Tauranga	143	54	100	156	176	336
31	Big box retail	Tauranga	83	35	58	82	105	192
42	Big box retail	Tauranga	63	32	36	58	82	173
87	Big box retail	Tauranga	52	25	36	54	68	148
54	Big box retail	Wellington	175	54	143	180	208	305
26	Big box retail	Wellington	105	48	93	114	129	222
20	Big box retail	Wellington	104	46	85	104	125	238
27	Big box retail	Wellington	90	40	62	88	108	212
21	Big box retail	Wellington	71	31	46	75	95	174
22	Big box retail	Wellington	54	22	59	62	67	80
92	Big box retail	Wellington	23	21	4	22	38	64
136	Cool store	Napier	645	539	69	600	1114	2225
140	Cool store	Nelson	1024	549	535	983	1504	3159
138	Cool store	Nelson	45	57	9	14	52	241
137	Cool store	Nelson	4	3	1	2	5	24
125	Corporate office	Auckland	1221	521	680	1262	1673	2482
148	Corporate office	Auckland	800	343	504	668	1100	1946

ID	Load type	Centre	Load (kW)					
			Mean	Standard deviation	25th Percentile	50th Percentile	75th Percentile	Maximum
128	Corporate office	Auckland	339	53	300	335	371	552
0	Corporate office	Auckland	191	112	100	118	318	485
114	Corporate office	Auckland	58	37	26	41	97	187
144	Corporate office	Wellington	291	211	142	168	462	1399
147	Corporate office	Wellington	177	131	78	110	292	752
146	Corporate office	Wellington	145	113	63	94	216	719
141	Corporate office	Wellington	138	75	88	96	181	462
143	Corporate office	Wellington	103	116	27	40	179	884
142	Corporate office	Wellington	50	38	26	32	62	245
145	Corporate office	Wellington	32	34	13	16	37	249
189	Dairy	Christchurch	24	21	7	16	38	104
165	Education	Auckland	391	160	240	381	498	932
132	Food market	Auckland	190	35	166	187	212	344
130	Food market	Auckland	6	3	4	5	8	16
131	Food market	Christchurch	160	32	137	157	179	273
133	Food market	Dunedin	334	85	270	310	390	708
134	Food market	Dunedin	137	133	41	66	233	699
129	Food market	Wellington	92	30	71	87	112	192
139	Greenhouse	Hamilton	112	43	80	103	143	228
135	Greenhouse	Hamilton	47	15	34	45	57	94
117	Grocery retail	Auckland	254	32	235	257	276	350
118	Grocery retail	Christchurch	208	34	181	212	232	332
124	Grocery retail	Dunedin	217	35	195	220	243	319
121	Grocery retail	Hamilton	215	25	199	217	232	300
119	Grocery retail	Napier	199	23	186	200	212	305
122	Grocery retail	Nelson	225	24	211	226	239	311
120	Grocery retail	Tauranga	206	25	189	207	221	308
123	Grocery retail	Wellington	218	38	194	220	244	347
162	Manufacturing	Auckland	2706	911	1919	2531	3460	6228
164	Manufacturing	Auckland	1474	496	1049	1387	1871	4939
163	Manufacturing	Auckland	1232	435	866	1144	1581	3272
187	Manufacturing	Wellington	463	442	19	515	863	1412
185	Manufacturing	Wellington	234	226	7	261	439	720
186	Manufacturing	Wellington	229	216	12	254	423	693
188	Manufacturing	Wellington	219	175	34	267	379	586
127	Production	Auckland	1664	703	950	1690	2291	3278
126	Production	Auckland	442	229	244	443	652	959
156	Retail	Auckland	838	564	308	541	1395	2177

ID	Load type	Centre	Load (kW)					
			Mean	Standard deviation	25th Percentile	50th Percentile	75th Percentile	Maximum
149	Retail	Auckland	226	152	60	214	388	447
152	Retail	Auckland	172	118	61	106	295	454
153	Retail	Auckland	124	72	57	85	200	254
151	Retail	Auckland	95	44	61	80	141	171
155	Retail	Auckland	90	120	11	30	120	614
154	Retail	Auckland	80	67	27	47	114	350
150	Retail	Auckland	51	34	19	34	88	114
161	Retail	Hamilton	657	421	246	506	1063	1603
158	Retail	Hamilton	200	126	74	199	324	468
159	Retail	Hamilton	187	130	74	98	304	476
160	Retail	Hamilton	144	106	44	84	249	376
157	Retail	Hamilton	126	73	48	135	180	404
110	Retail warehousing	Auckland	297	41	270	296	324	468
112	Retail warehousing	Auckland	176	47	158	172	198	350
111	Retail warehousing	Auckland	144	33	108	159	168	238
113	Retail warehousing	Christchurch	92	62	35	83	139	266
166	Warehousing	Auckland	350	111	278	345	423	714
167	Warehousing	Christchurch	561	81	509	552	605	1074
169	Warehousing	Christchurch	187	34	166	185	209	361
173	Warehousing	Christchurch	186	120	29	251	284	531
168	Warehousing	Christchurch	182	29	164	181	200	353
170	Warehousing	Christchurch	53	5	50	53	56	108
171	Warehousing	Napier	101	66	25	139	153	280
172	Warehousing	Tauranga	279	52	257	286	313	526
174	Waste water treatment	Auckland	5366	1682	4248	5312	6493	13133
177	Waste water treatment	Auckland	255	77	203	245	294	528
183	Waste water treatment	Auckland	183	197	38	101	212	687
184	Waste water treatment	Auckland	130	165	54	64	106	706
179	Waste water treatment	Auckland	121	9	115	120	126	156
182	Waste water treatment	Auckland	113	138	54	61	99	567
176	Waste water treatment	Auckland	34	21	22	28	40	140
178	Waste water treatment	Auckland	11	2	10	11	11	20
181	Water supply	Auckland	3520	1214	2472	3945	4590	5186
180	Water supply	Auckland	243	78	216	236	255	991
175	Water supply	Auckland	20	22	1	15	35	124

12 Appendix Five – Detailed case study results

Appendix Five contains detailed results for each load type, consisting of:

1. Graphs of daily load profiles by month, separated into business days and non-business days, for a single site;
2. A graphical presentation of the financial results for the eight sites with highest IRRs;
3. A financial sensitivity analysis for the four sites with the highest IRRs;
4. A graph showing seven days of load and modelled generation for a single site. This is centred on the day on which peak load coincident with a network peak period occurred;
5. A graph of IRR versus solar capacity, which illustrates how the model optimises system capacity by maximising IRR.

12.1 Retail (RTL)

The retail load type is that of a retail mall encompassing many retailers.

Figures follow on the next five pages.

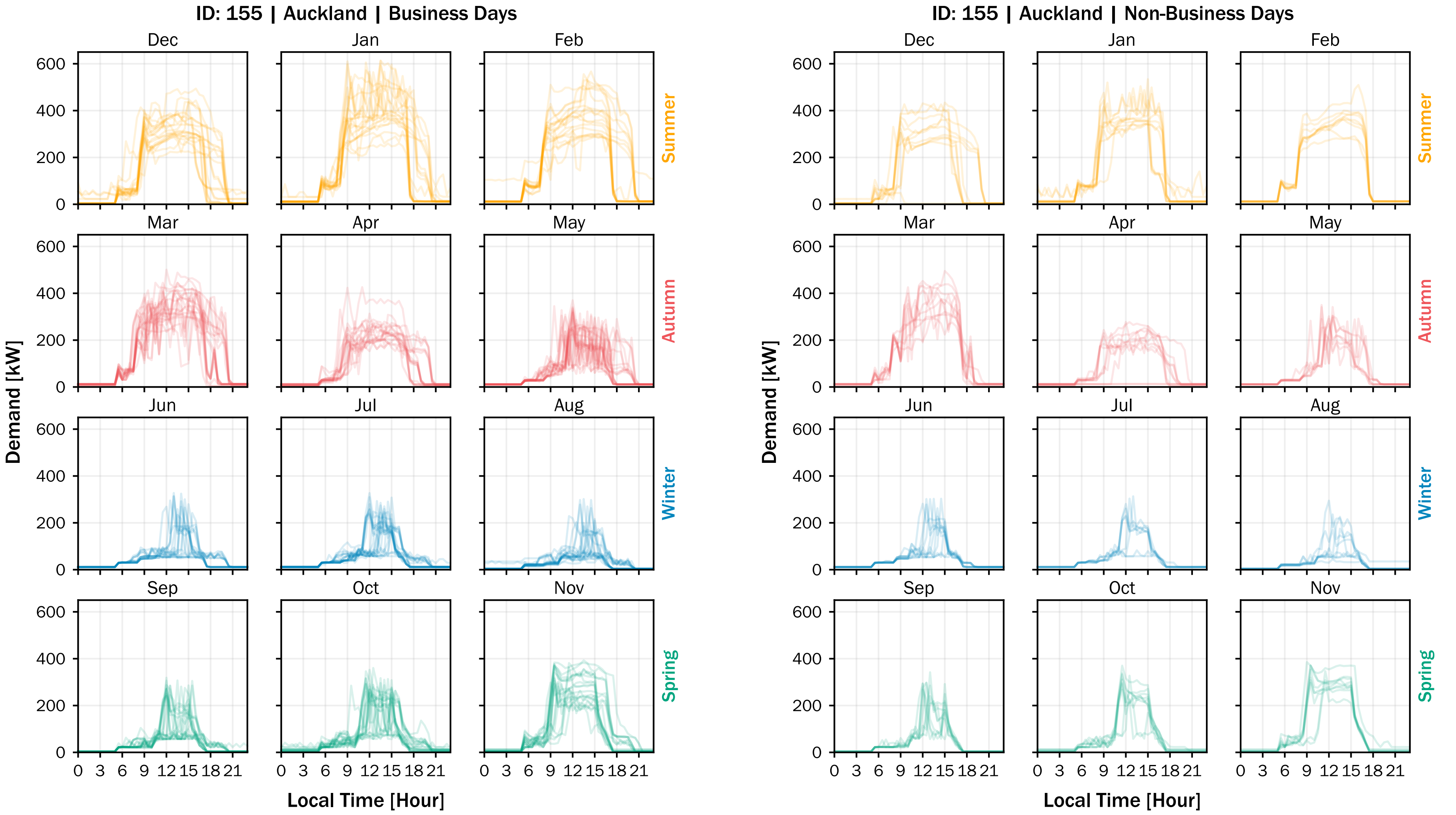
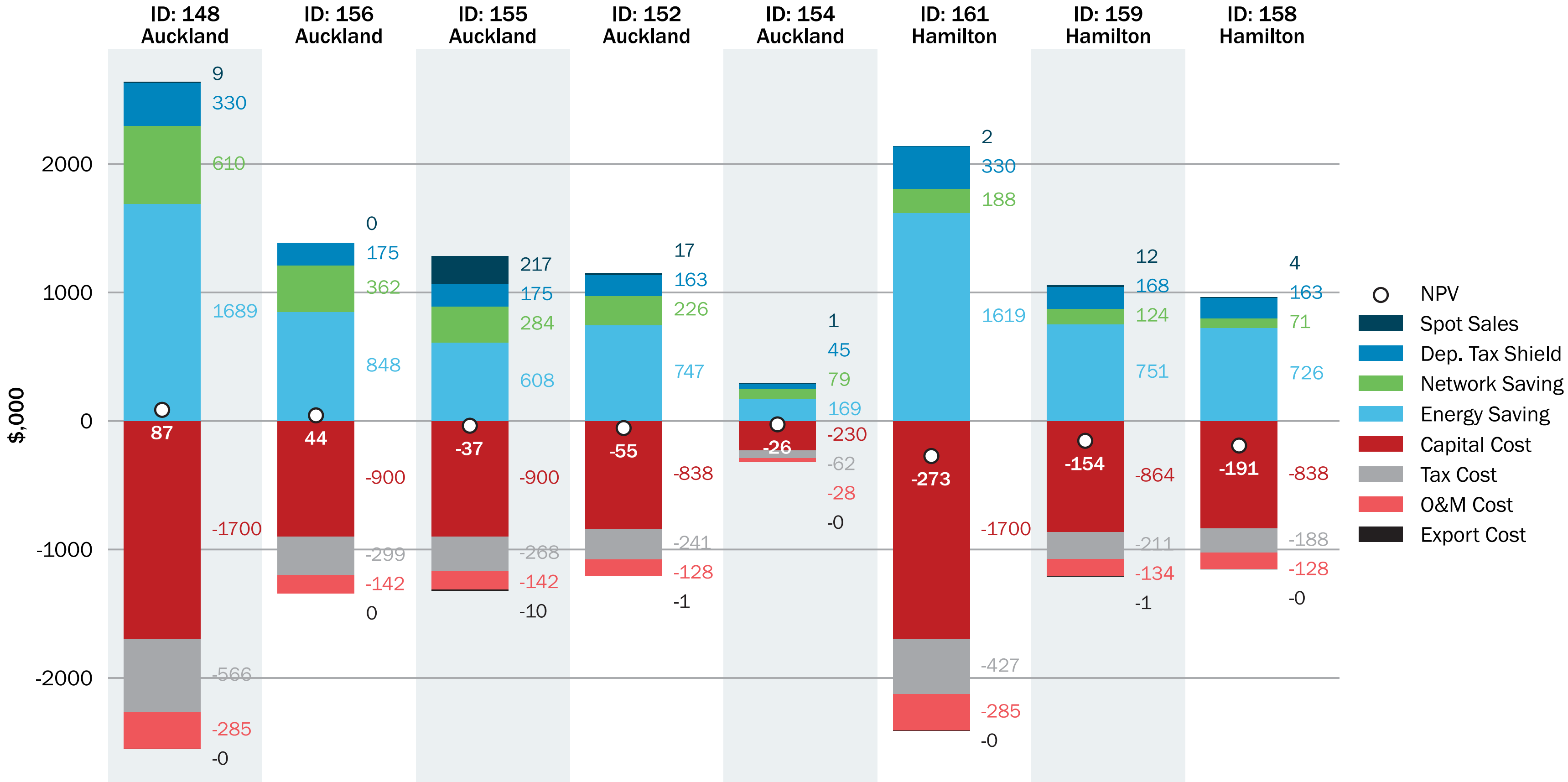


Figure 15: 2019 calendar year load of retail Site 155. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



	ID: 148	ID: 156	ID: 155	ID: 152	ID: 154	ID: 161	ID: 159	ID: 158
IRR	7.6 %	7.6 %	6.5 %	6.2 %	5.6 %	5.0 %	4.8 %	4.1 %
PV	1000 kW	500 kW	500 kW	450 kW	100 kW	1000 kW	470 kW	450 kW
Capacity Factor	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Average Load	800 kW	838 kW	90 kW	172 kW	80 kW	657 kW	187 kW	200 kW
Max Load	1840 kW	2111 kW	600 kW	443 kW	343 kW	1546 kW	468 kW	446 kW
Self Consumption	99.0 %	100.0 %	69.6 %	96.2 %	99.3 %	99.8 %	97.7 %	99.1 %

Figure 16: Financial results of analysis of solar at retail Site 155 and another seven sites in descending order of IRR. All sites are retail except 148 which is a corporate office associated with the same company.

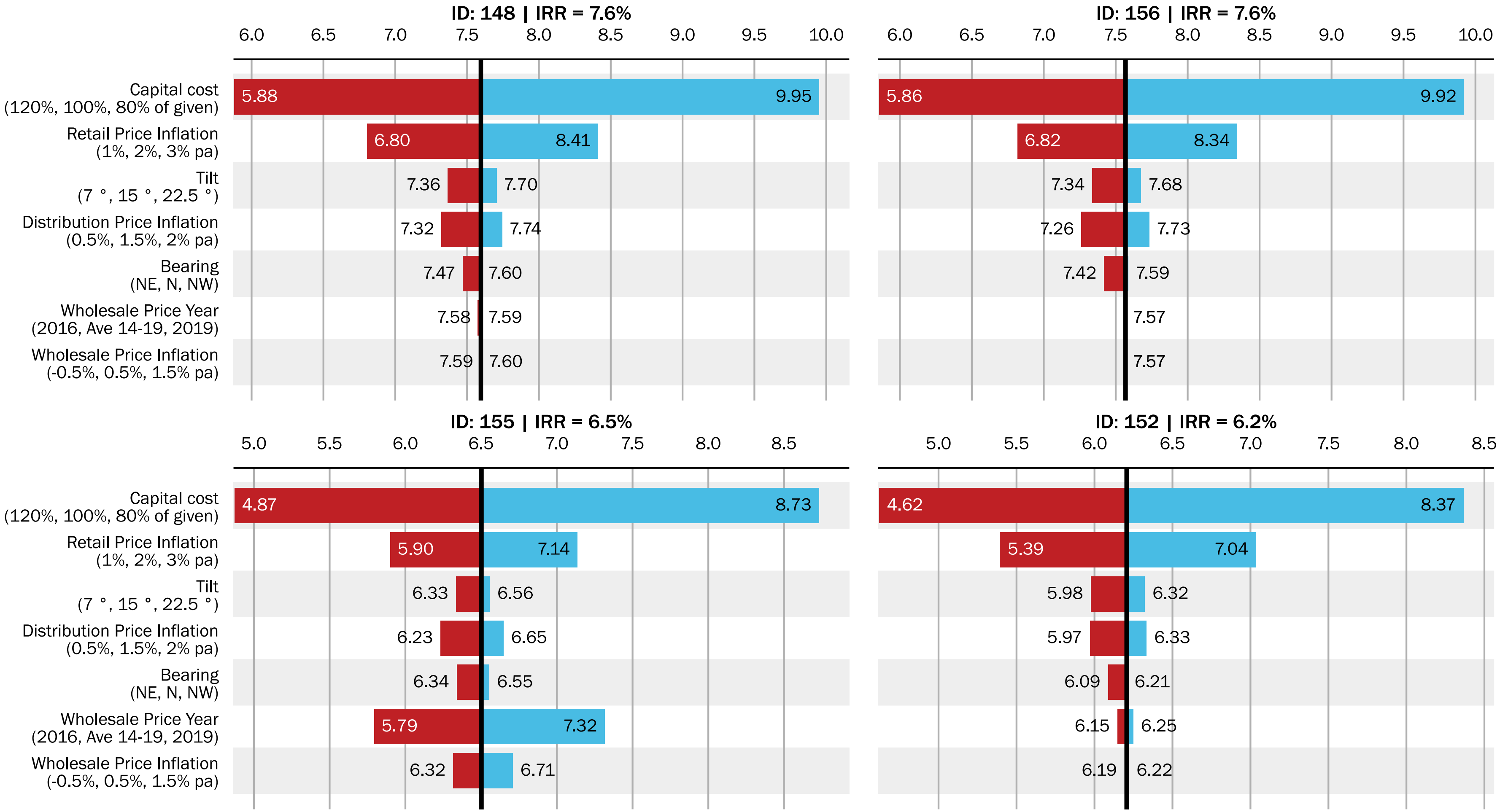


Figure 17: Sensitivity of IRR to inputs for retail Site 155 and three other sites. As per above figure, all sites are retail except 148.

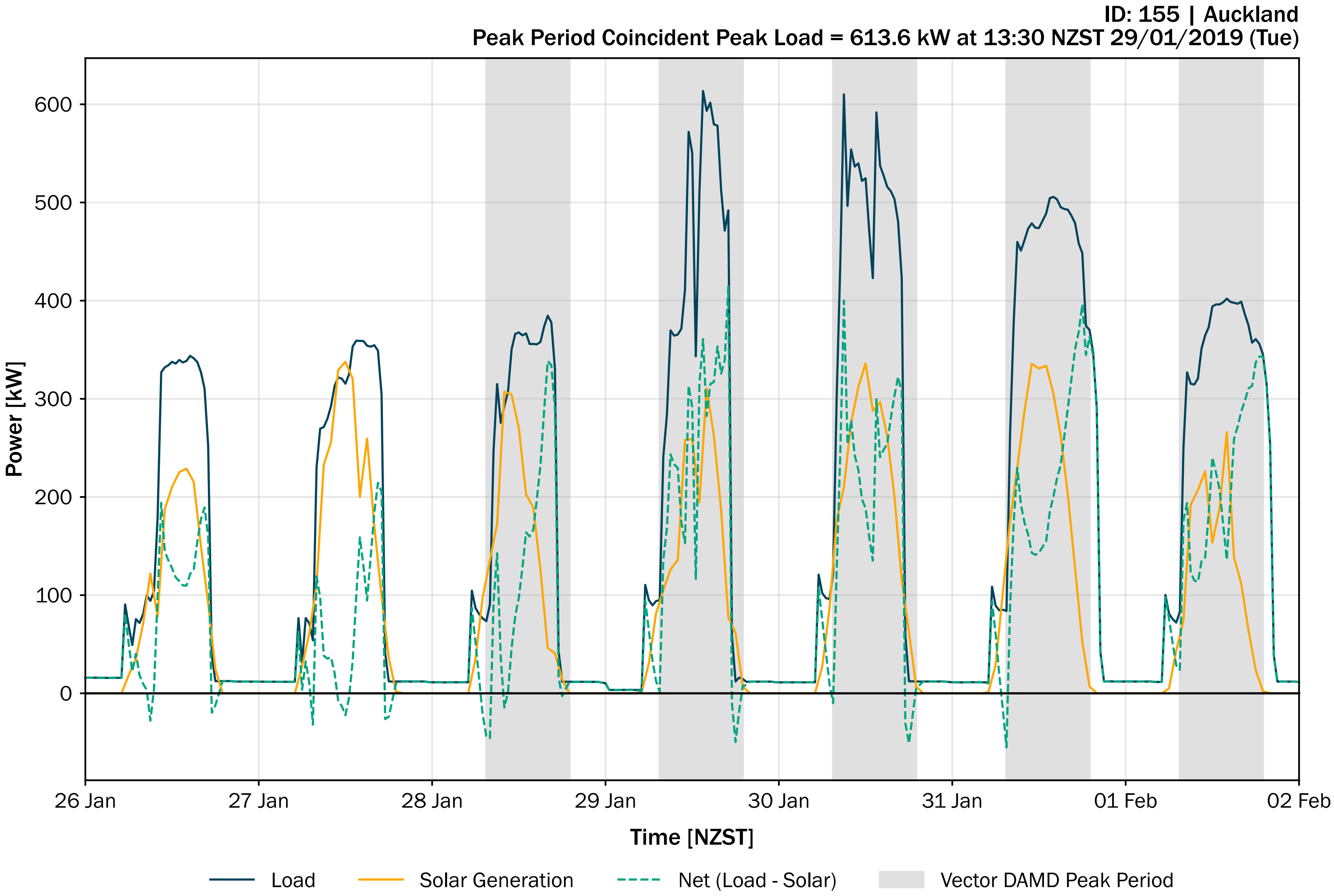


Figure 18: Site 155's load profiles including the time at which the highest kVA load occurred coincident with Vector's peak period.

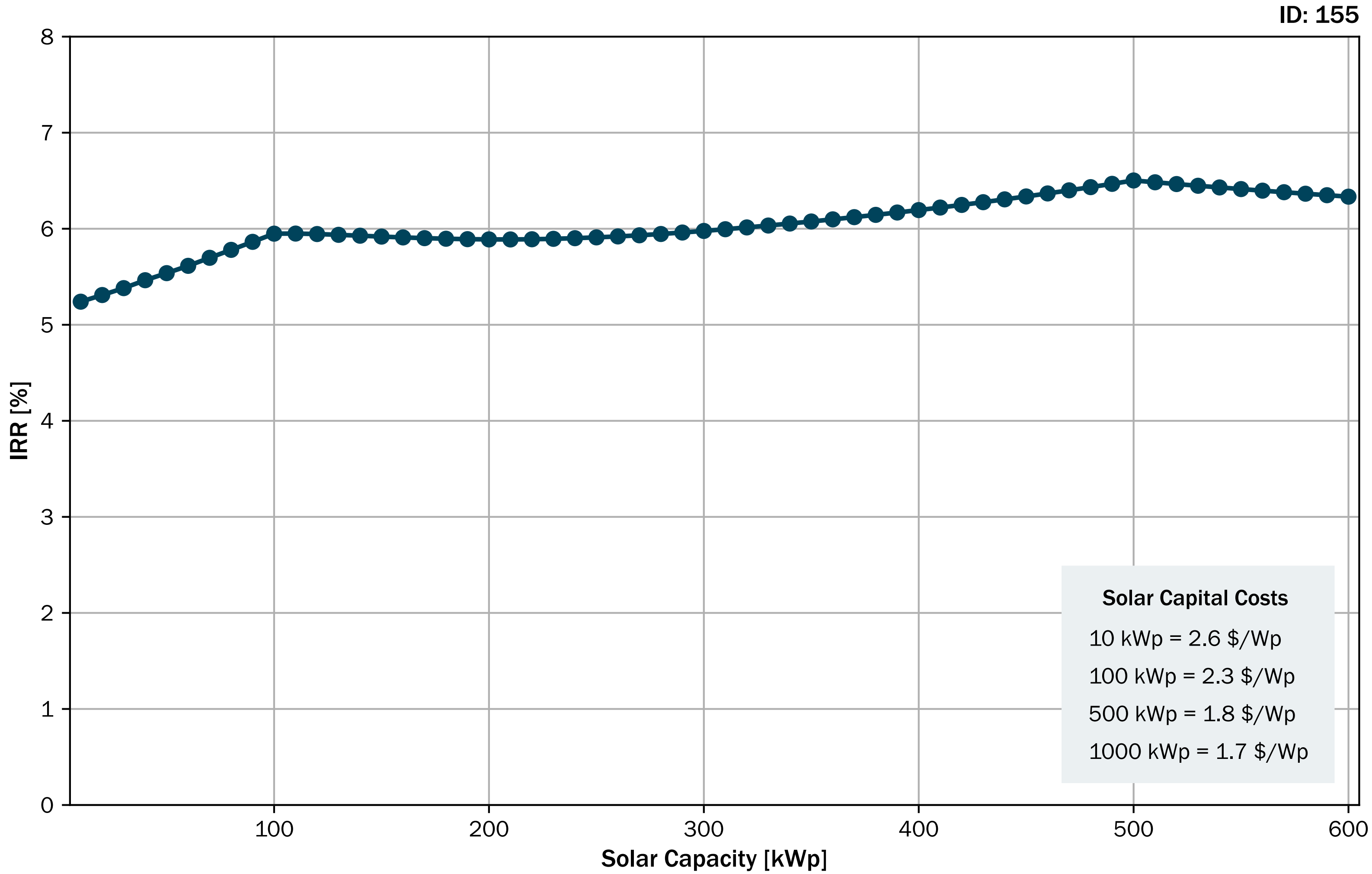


Figure 19: IRR versus solar system capacity for retail Site 155.

12.2 Grocery retail (FRWRL)

The grocery retail load type is that of a food and grocery supermarket with high refrigeration load.

Figures follow on the next five pages.

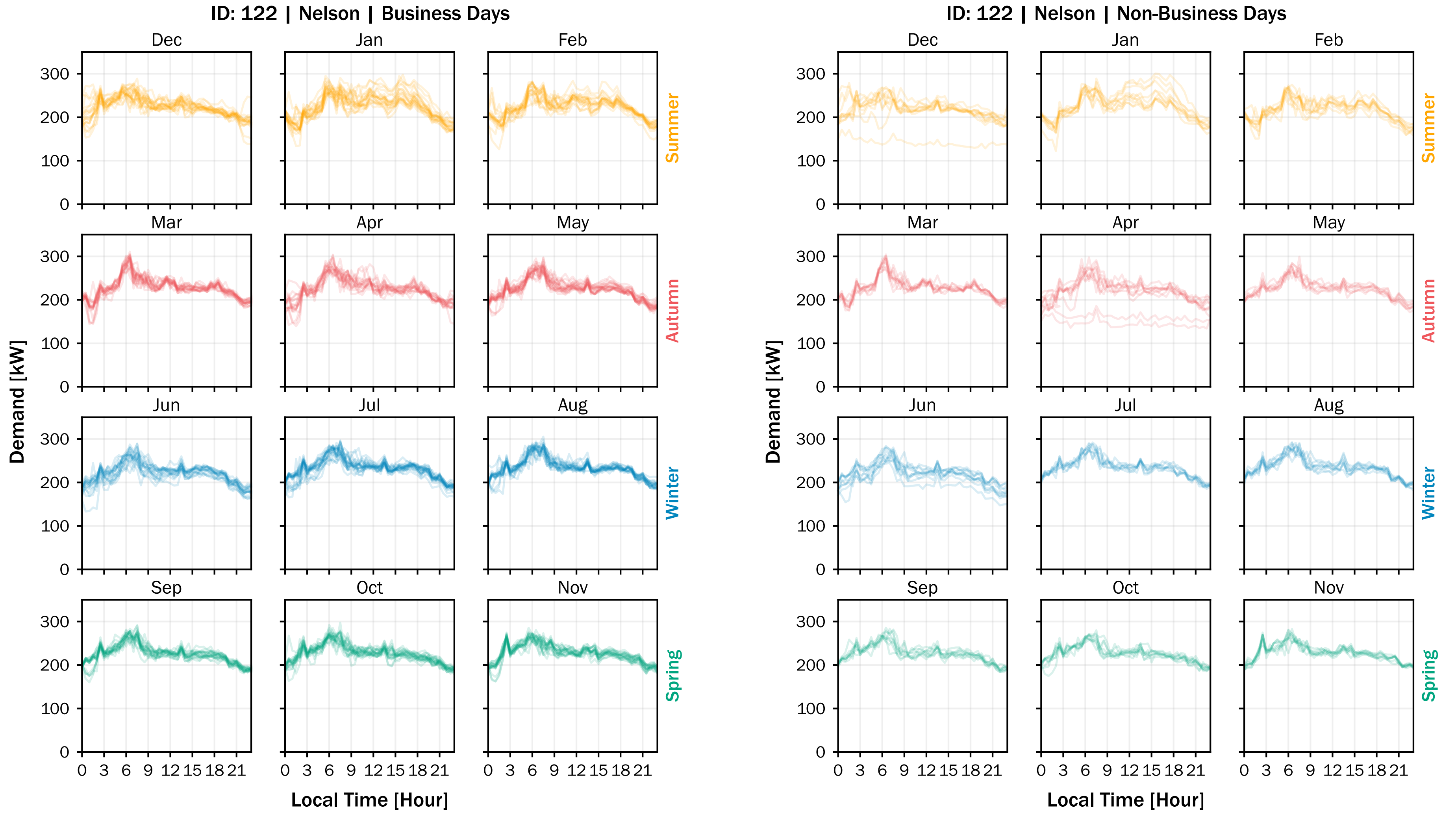
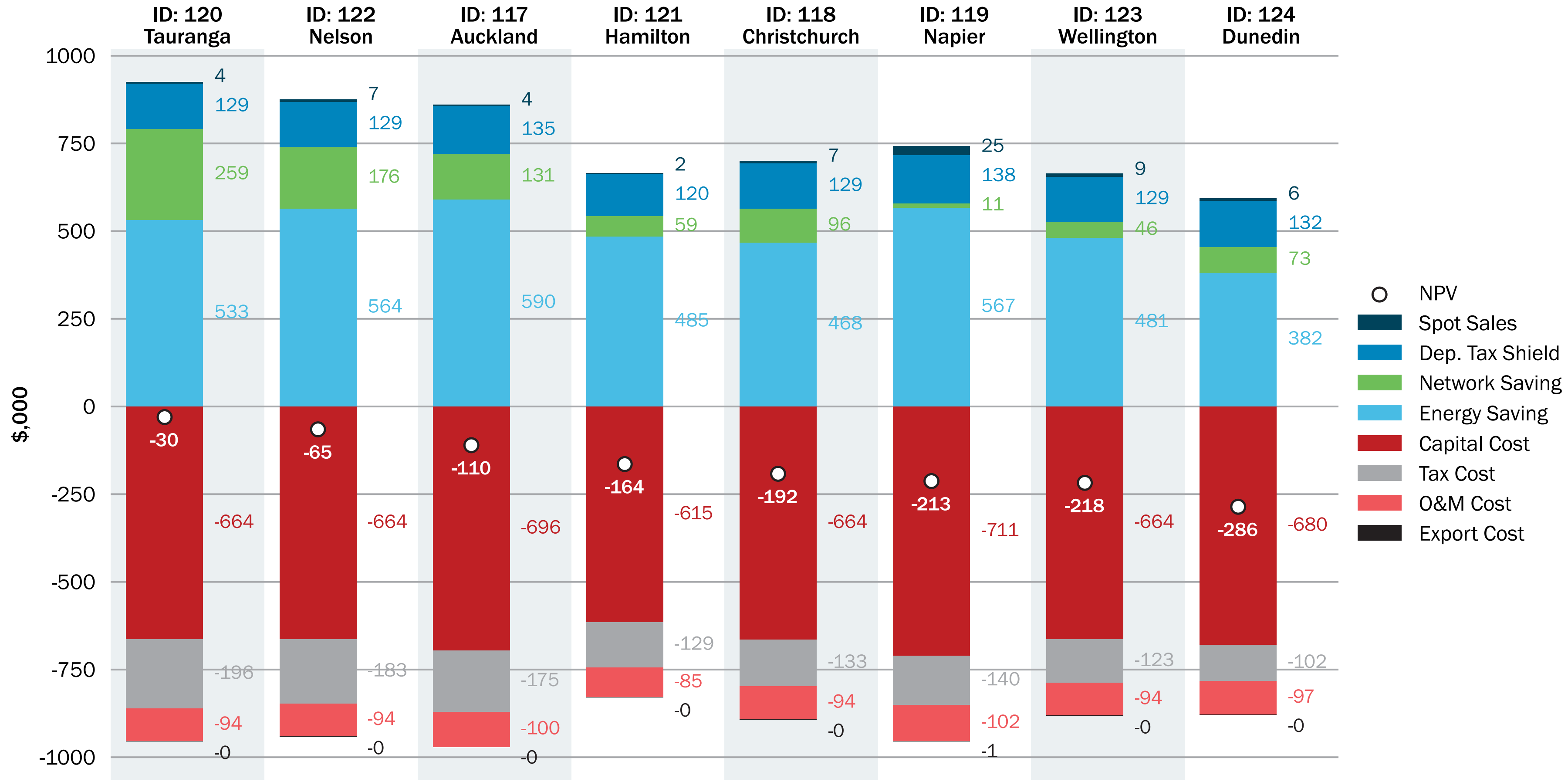


Figure 20: 2019 calendar year load of grocery retail Site 122. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



IRR	6.5 %	5.8 %	5.0 %	3.5 %	3.2 %	3.0 %	2.6 %	1.1 %
PV	330 kW	330 kW	350 kW	300 kW	330 kW	360 kW	330 kW	340 kW
Capacity Factor	0.15	0.16	0.15	0.15	0.14	0.16	0.15	0.12
Average Load	206 kW	225 kW	254 kW	215 kW	208 kW	199 kW	218 kW	217 kW
Max Load	325 kW	327 kW	350 kW	299 kW	330 kW	351 kW	329 kW	332 kW
Self Consumption	98.5 %	97.6 %	98.8 %	99.3 %	97.5 %	93.8 %	97.1 %	97.4 %

Figure 21: Financial results of analysis of solar at grocery retail Site 122 and another seven sites.

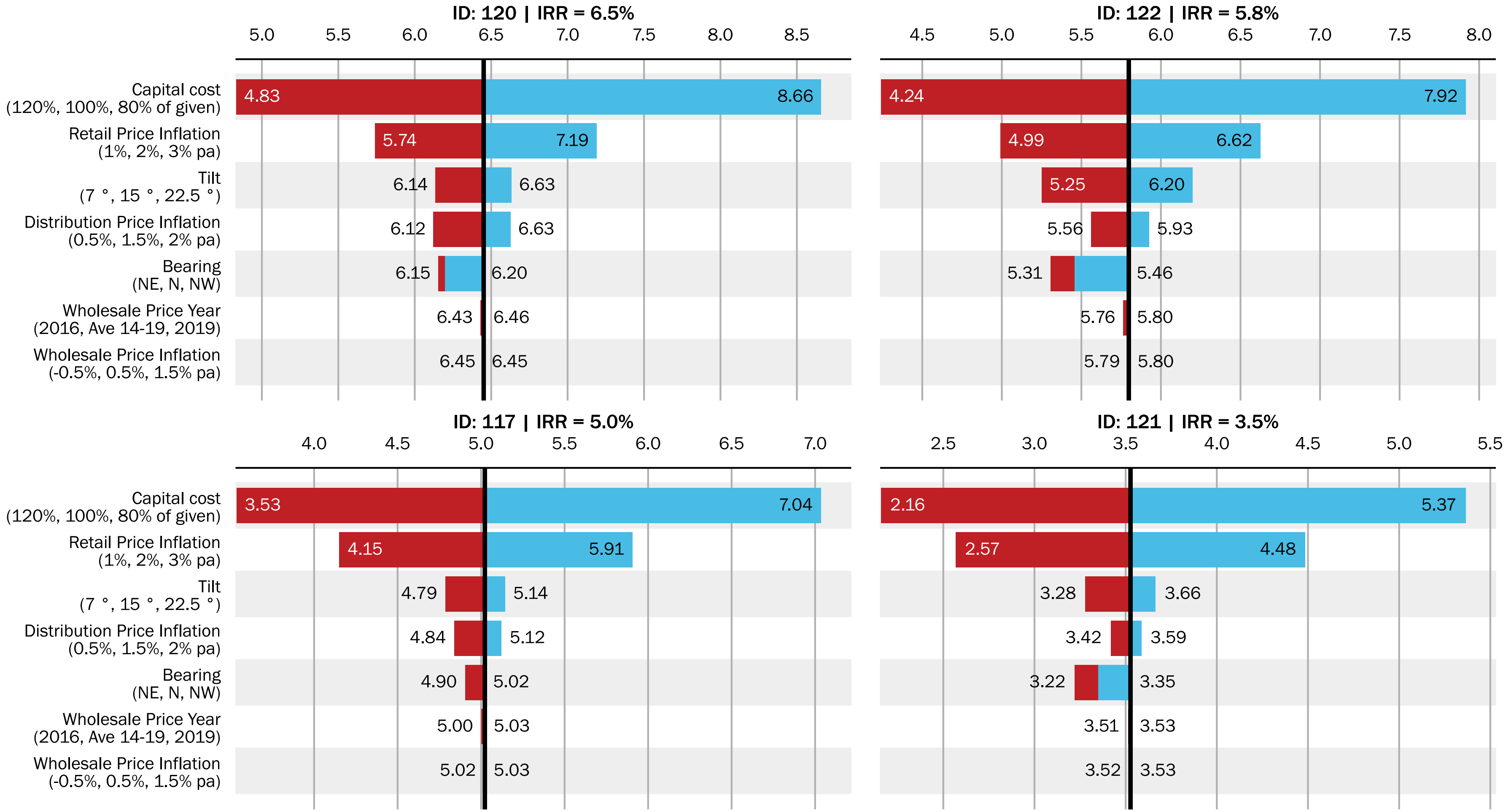


Figure 22: Sensitivity of IRR to inputs for retail Site 122 and three other sites.

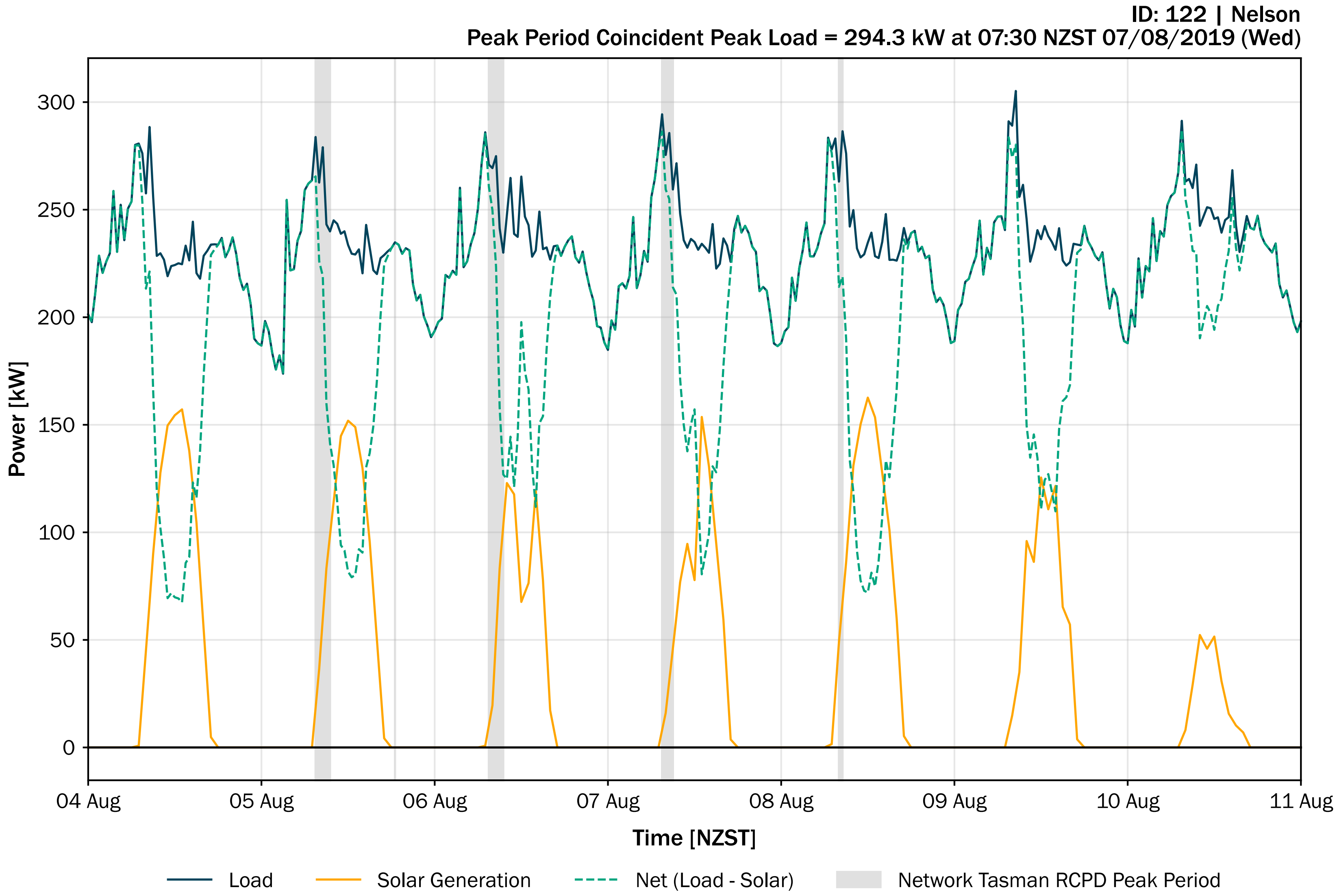


Figure 23: Site 122's load profiles including the time at which the highest kW load occurred coincident with Network Tasman's peak periods.

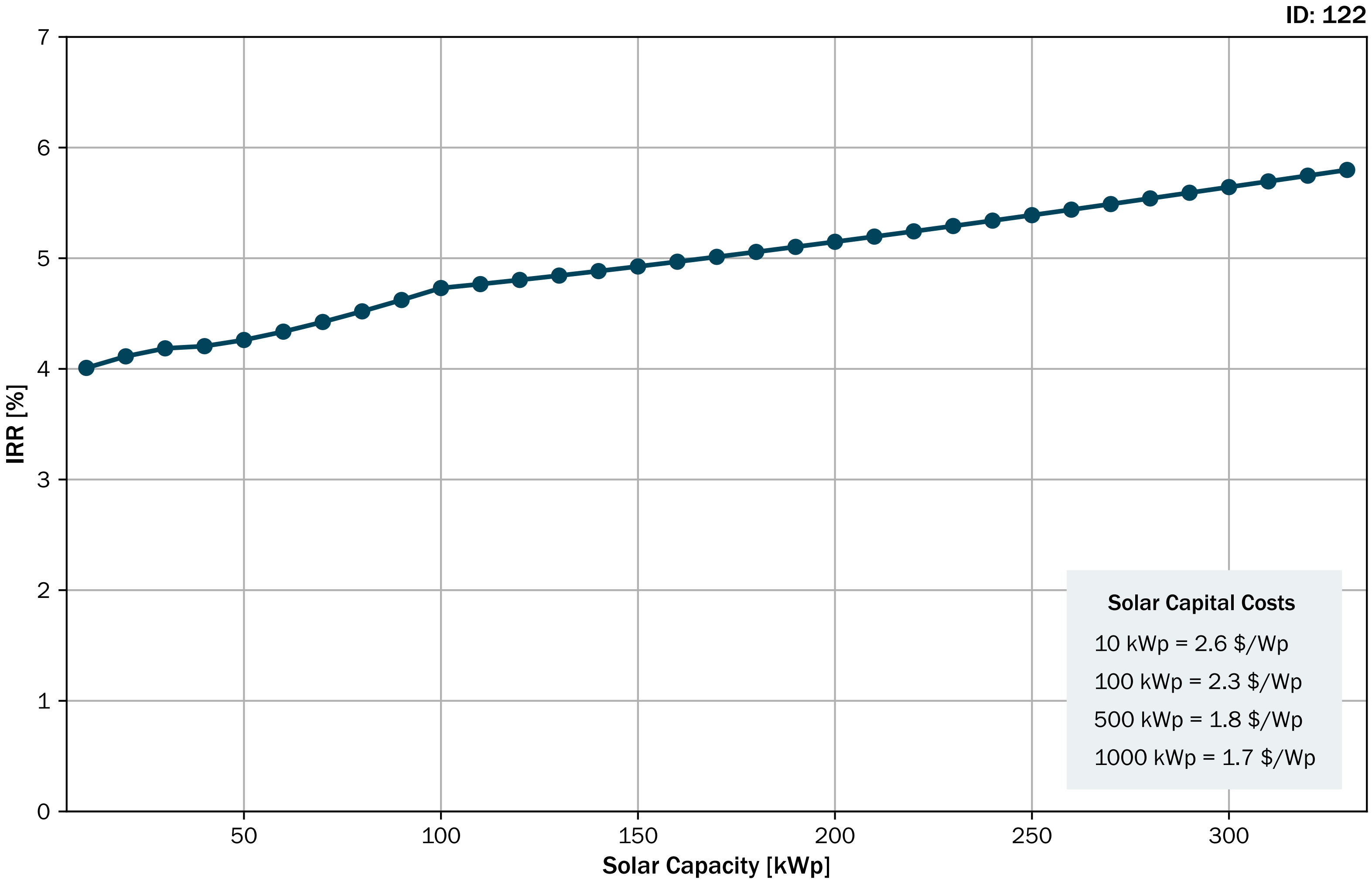


Figure 24: IRR versus solar system capacity for retail Site 122.

12.3 Food market (MKT)

The food market load type is that of a wholesale food market floor.

Figures follow on the next five pages.

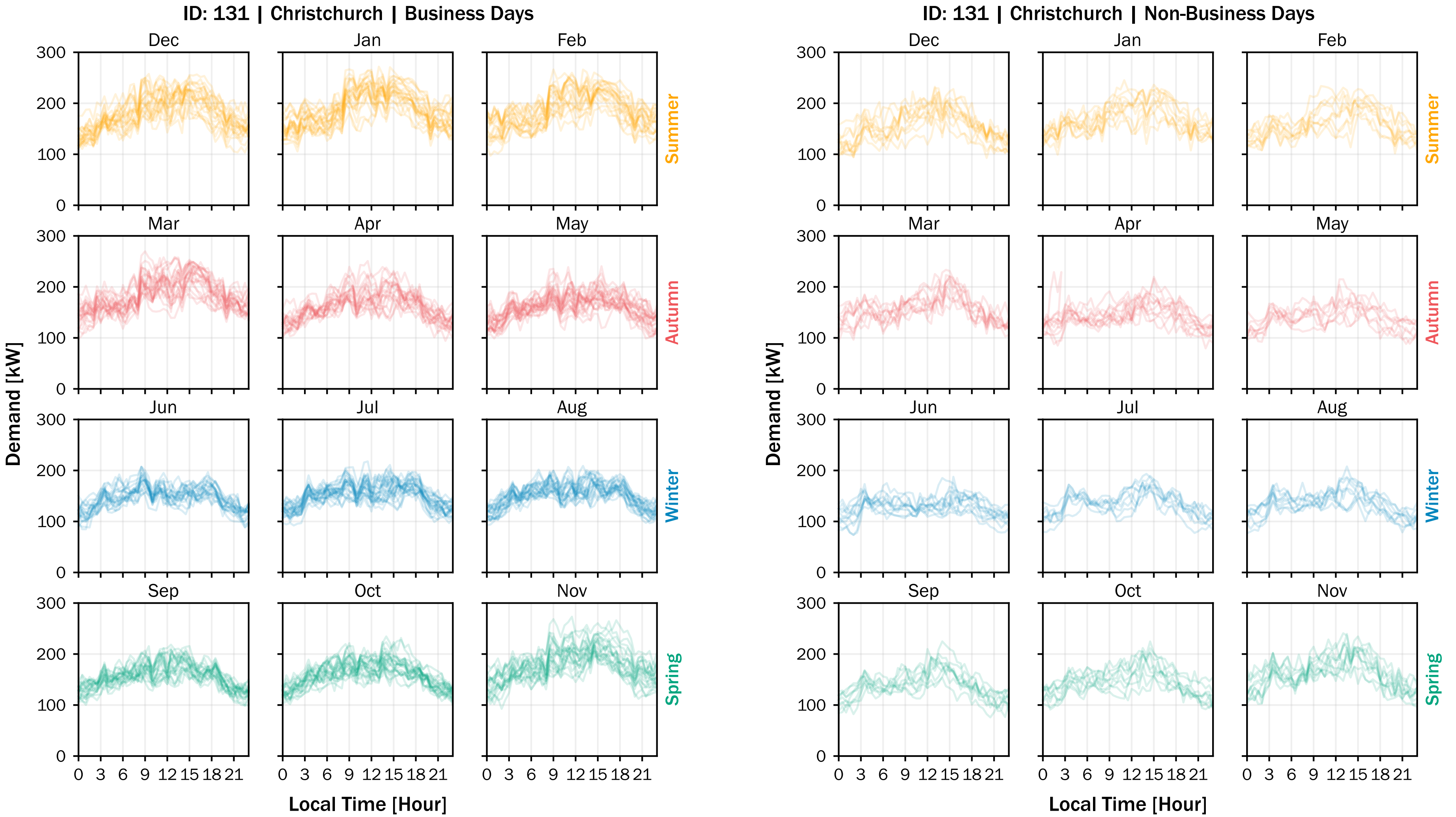
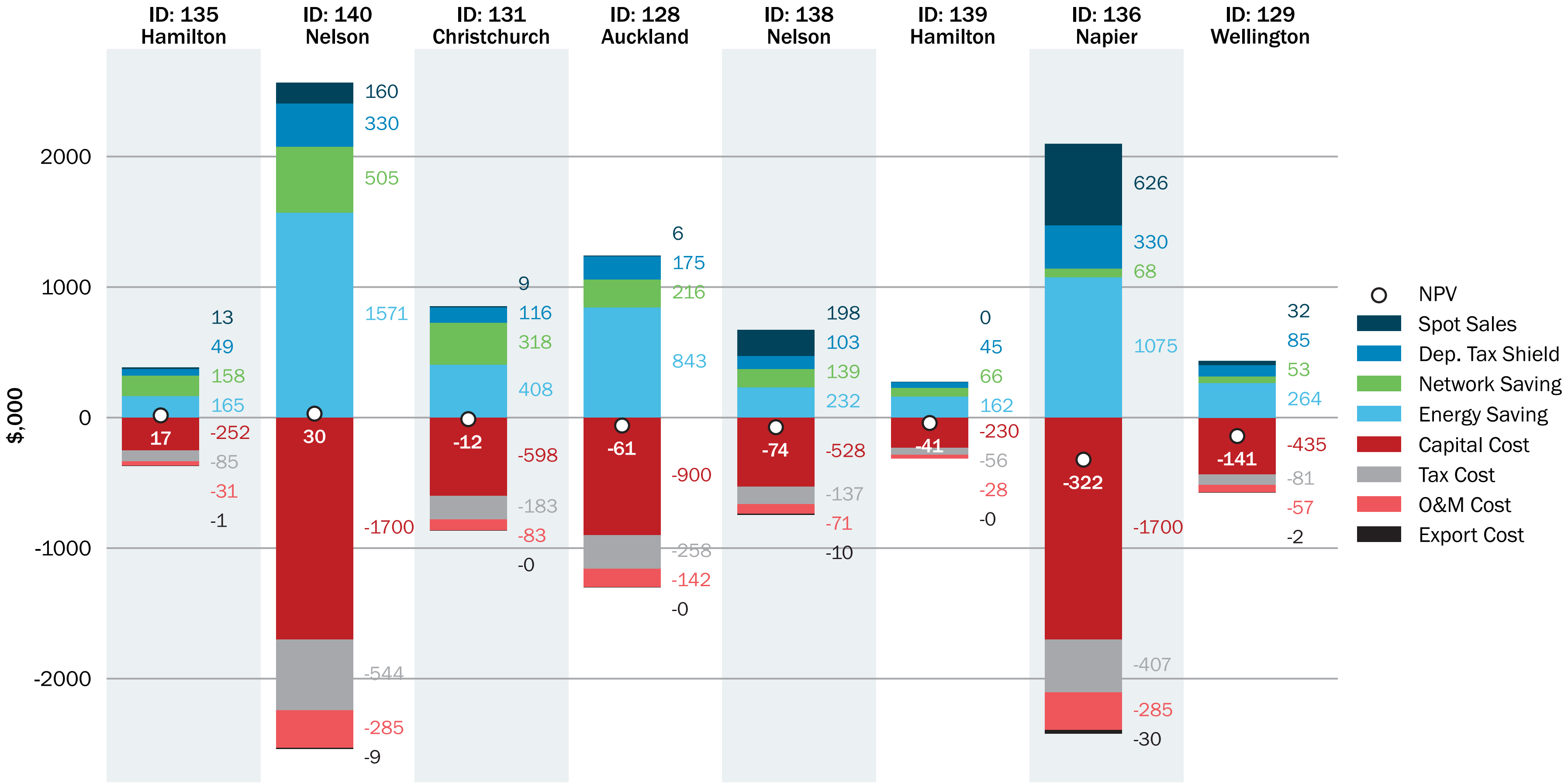


Figure 25: 2019 calendar year load of market Site 131. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



IRR	7.8 %	7.2 %	6.8 %	6.2 %	5.2 %	4.7 %	4.6 %	2.6 %
PV	110 kW	1000 kW	290 kW	500 kW	250 kW	100 kW	1000 kW	200 kW
Capacity Factor	0.15	0.16	0.14	0.15	0.16	0.15	0.16	0.15
Average Load	47 kW	1024 kW	160 kW	339 kW	45 kW	112 kW	645 kW	92 kW
Max Load	102 kW	2854 kW	288 kW	559 kW	247 kW	247 kW	2154 kW	193 kW
Self Consumption	90.3 %	87.8 %	96.3 %	98.6 %	47.8 %	100.0 %	59.4 %	85.7 %

Figure *26*: Financial results of analysis of solar at market Site 131 and another seven sites. Note that only sites 131 (third from left) and 129 (far right) are markets; other sites are for different load types associated with the same company and covered elsewhere.

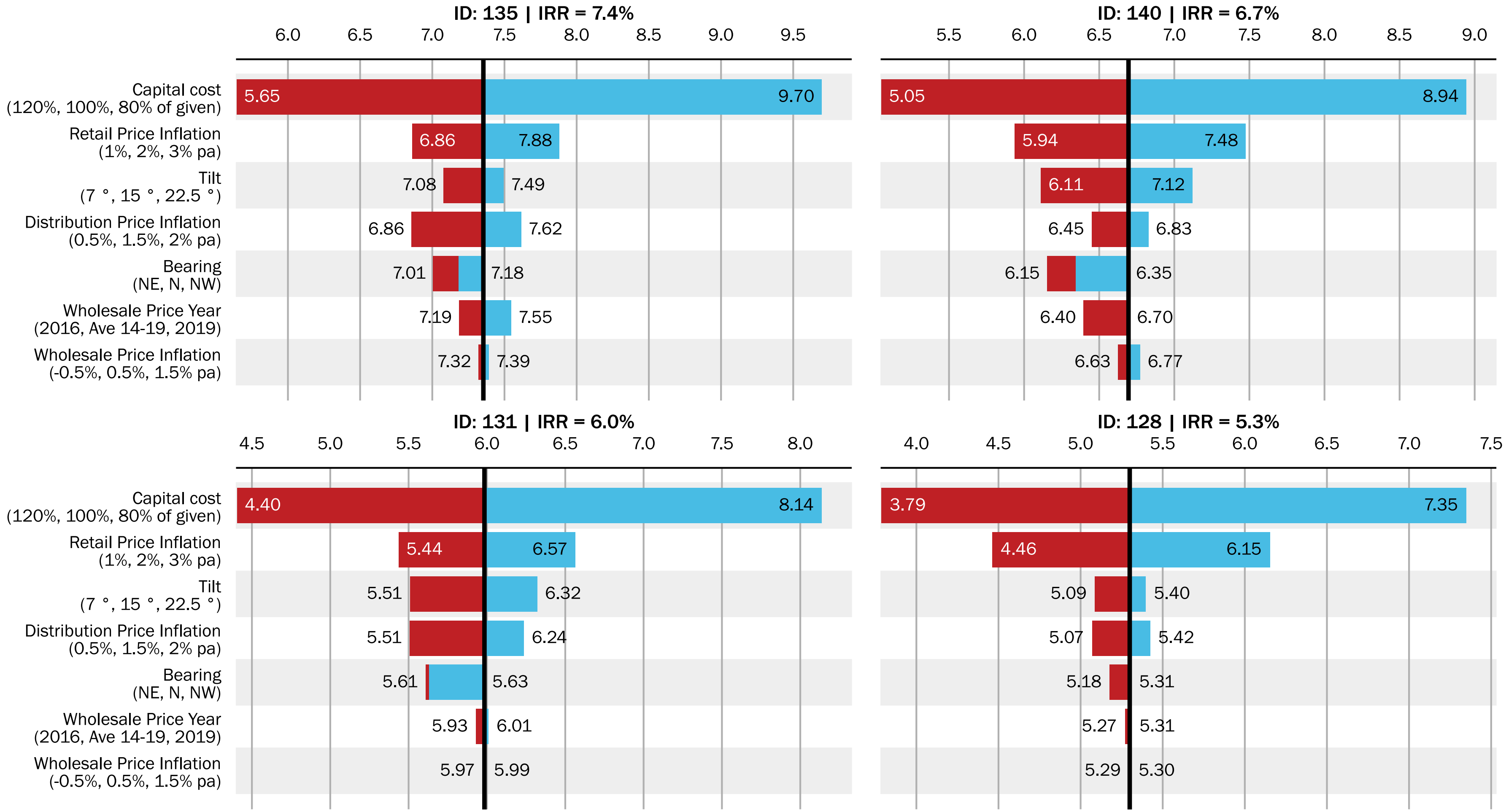


Figure 27: Sensitivity of IRR to inputs for market Site 131 and three other sites. Only site 131 (bottom left) is a market.

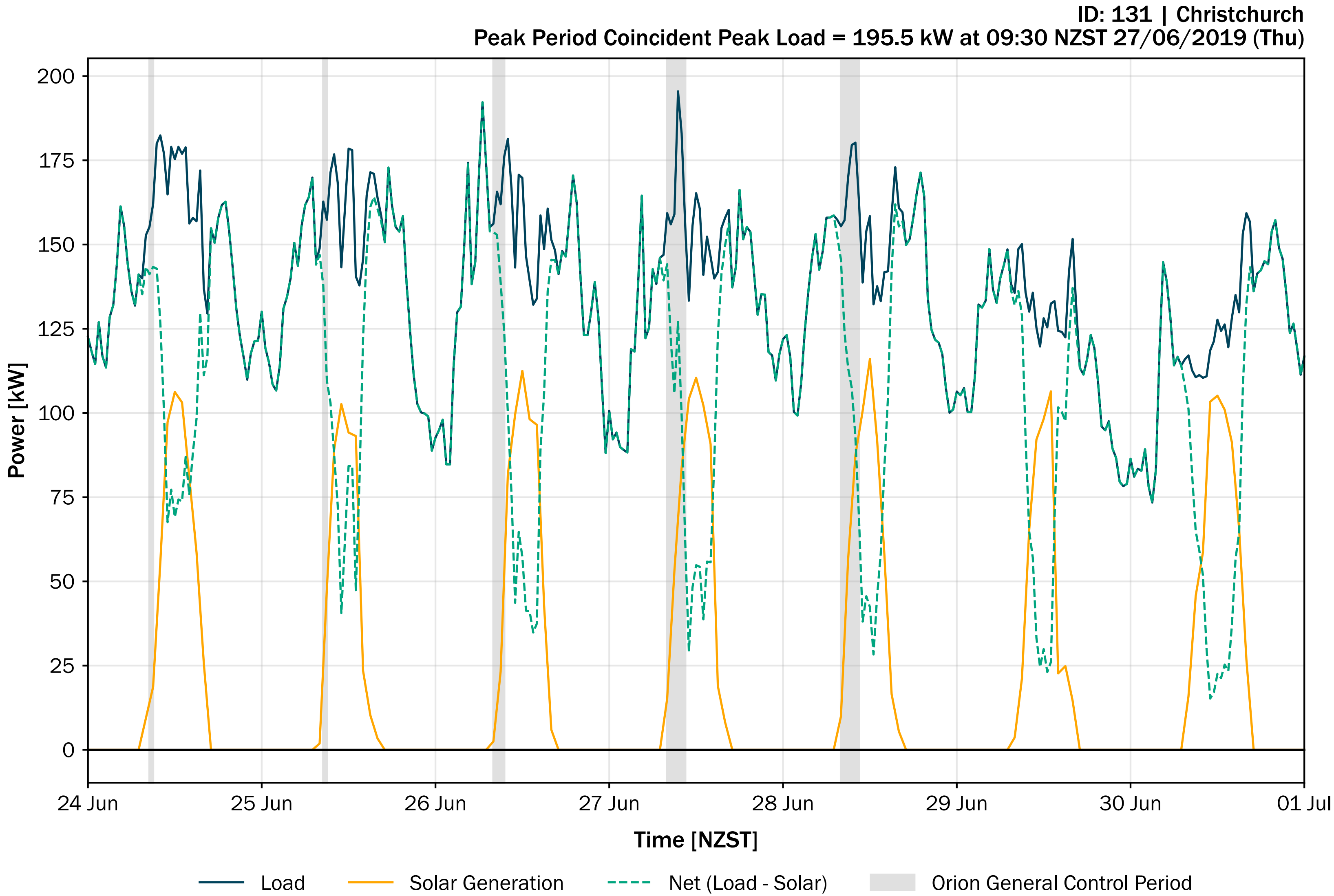


Figure 28: Site 131's load profiles including the time at which the highest kW load occurred coincident with Orion's peak period.

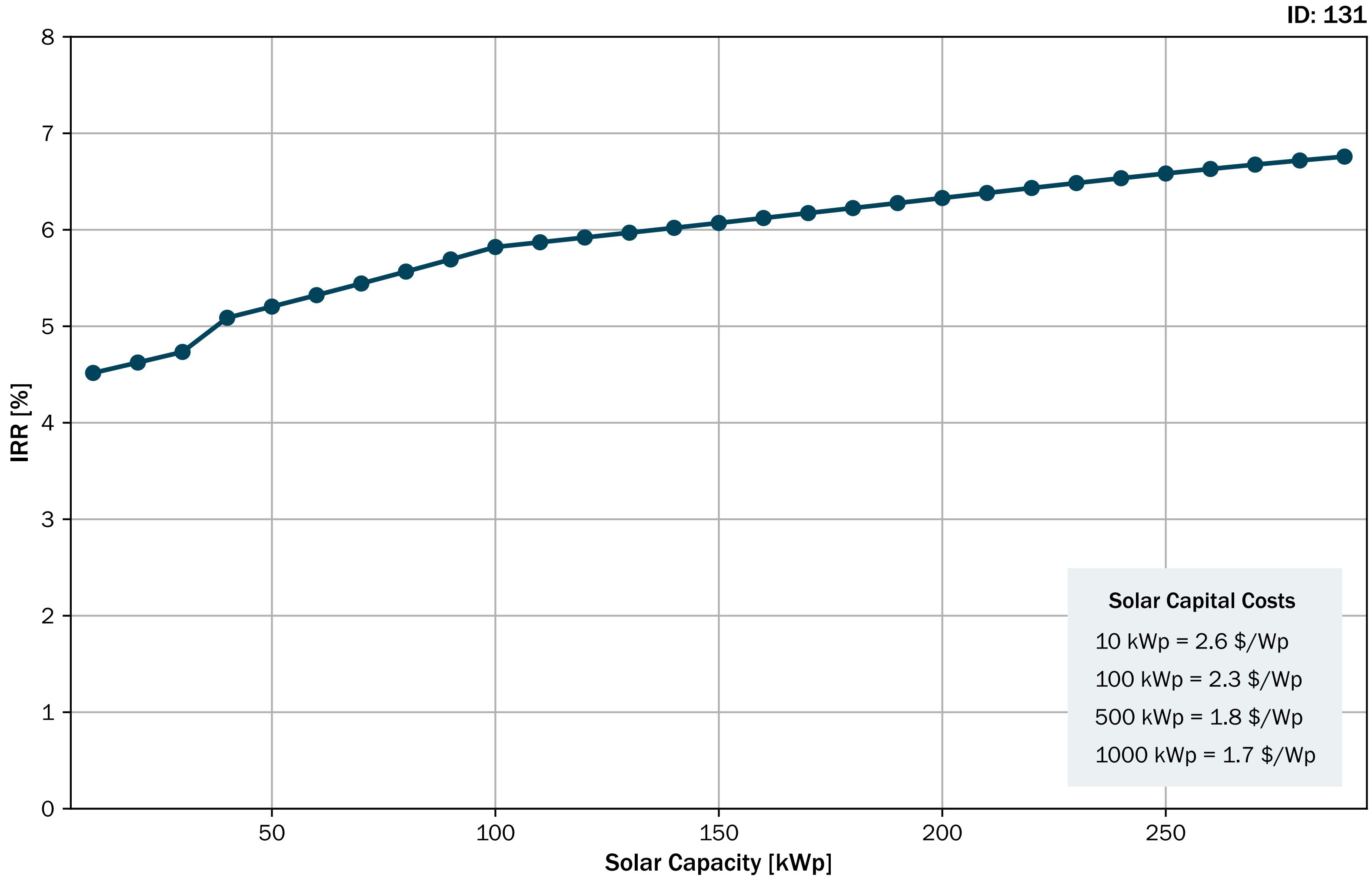


Figure 29: IRR versus solar system capacity for market Site 131.

12.4 Cool store (CLSTR) and Greenhouse (GRNHS)

The cool store load type is that of a horticulture produce cool store and packhouse.

The greenhouse load type is that of a horticultural greenhouse.

Figures follow on the next five pages.

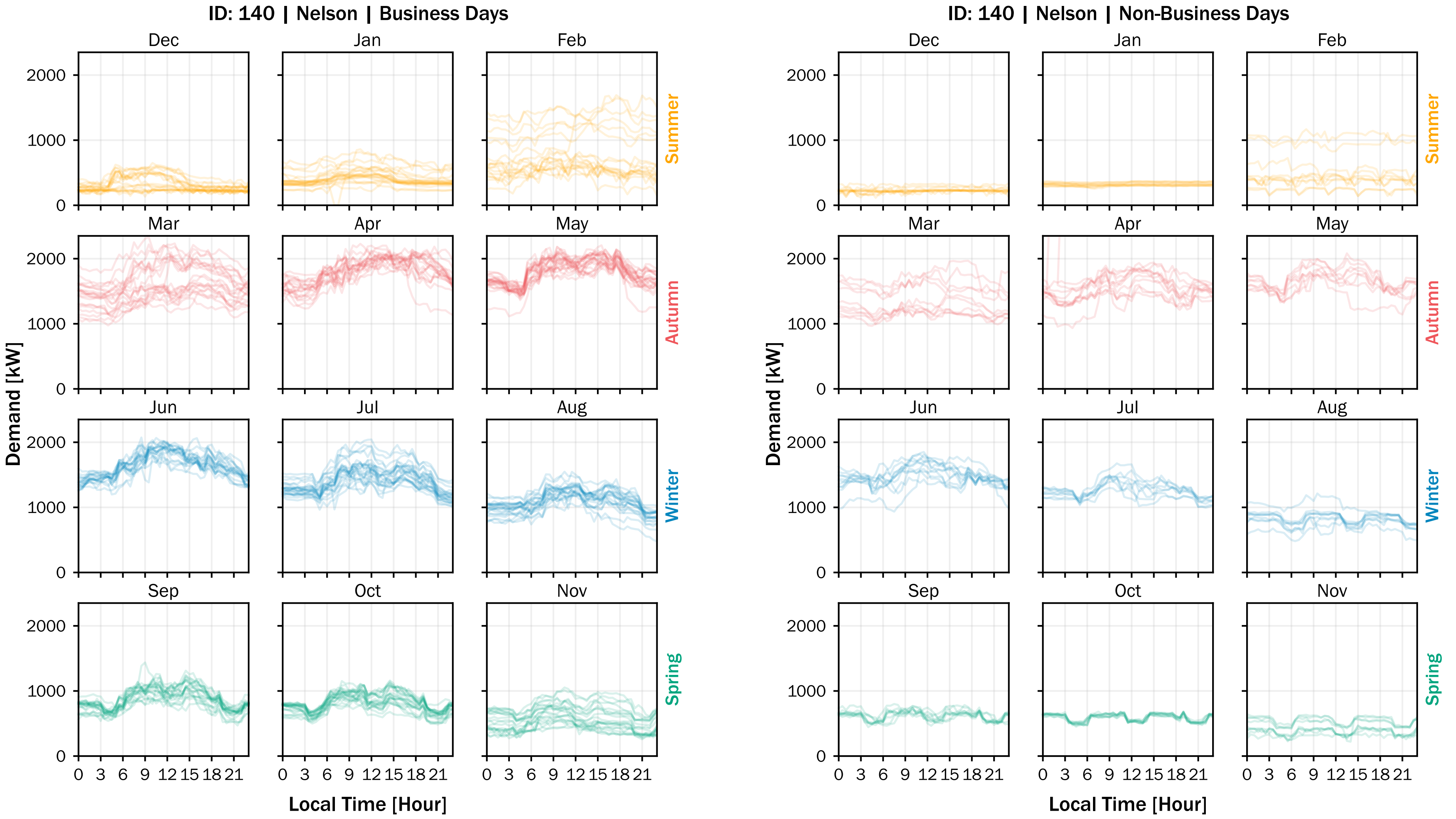
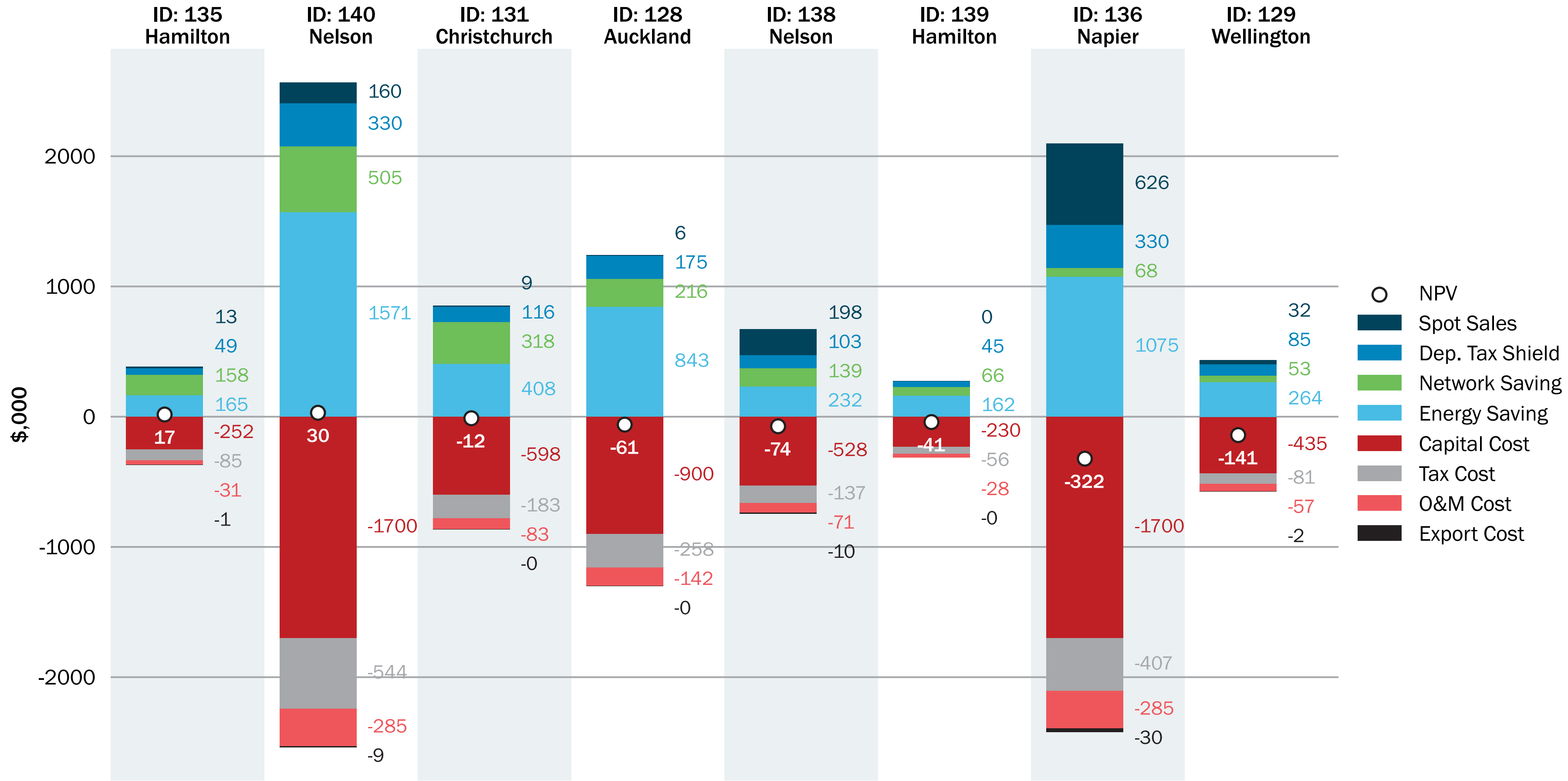


Figure 30: 2019 calendar year load of cool store Site 140. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



IRR	7.8 %	7.2 %	6.8 %	6.2 %	5.2 %	4.7 %	4.6 %	2.6 %
PV	110 kW	1000 kW	290 kW	500 kW	250 kW	100 kW	1000 kW	200 kW
Capacity Factor	0.15	0.16	0.14	0.15	0.16	0.15	0.16	0.15
Average Load	47 kW	1024 kW	160 kW	339 kW	45 kW	112 kW	645 kW	92 kW
Max Load	102 kW	2854 kW	288 kW	559 kW	247 kW	247 kW	2154 kW	193 kW
Self Consumption	90.3 %	87.8 %	96.3 %	98.6 %	47.8 %	100.0 %	59.4 %	85.7 %

Figure 31: Financial results of analysis of solar at cool store Site 140 (second from left) and another seven sites associated with the same company. Sites 138 and 136 are also cool stores, while sites 135 and 139 are greenhouses.

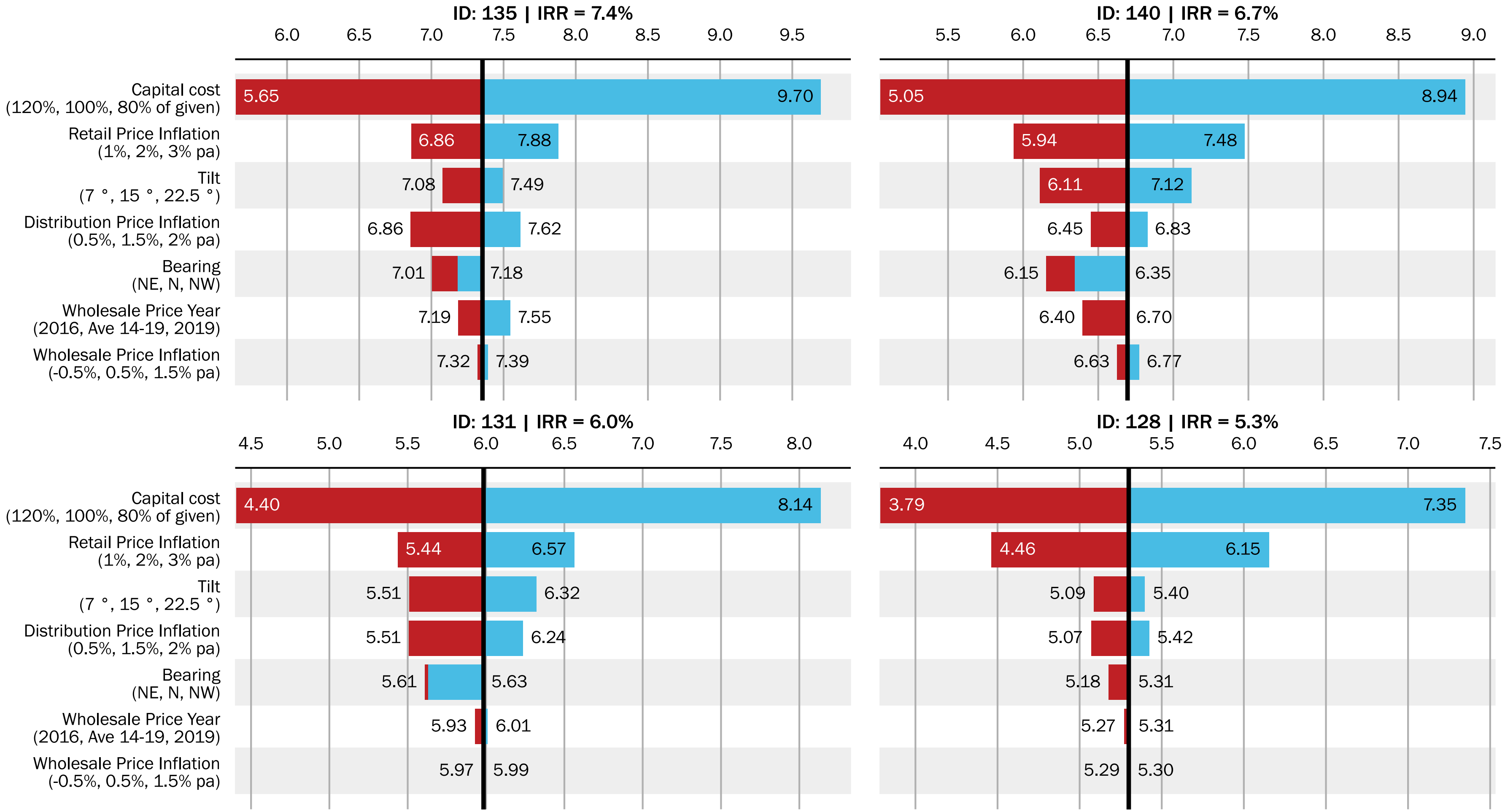


Figure 32: Sensitivity of IRR to inputs for cool store Site 140 and three other sites associated with the same company.

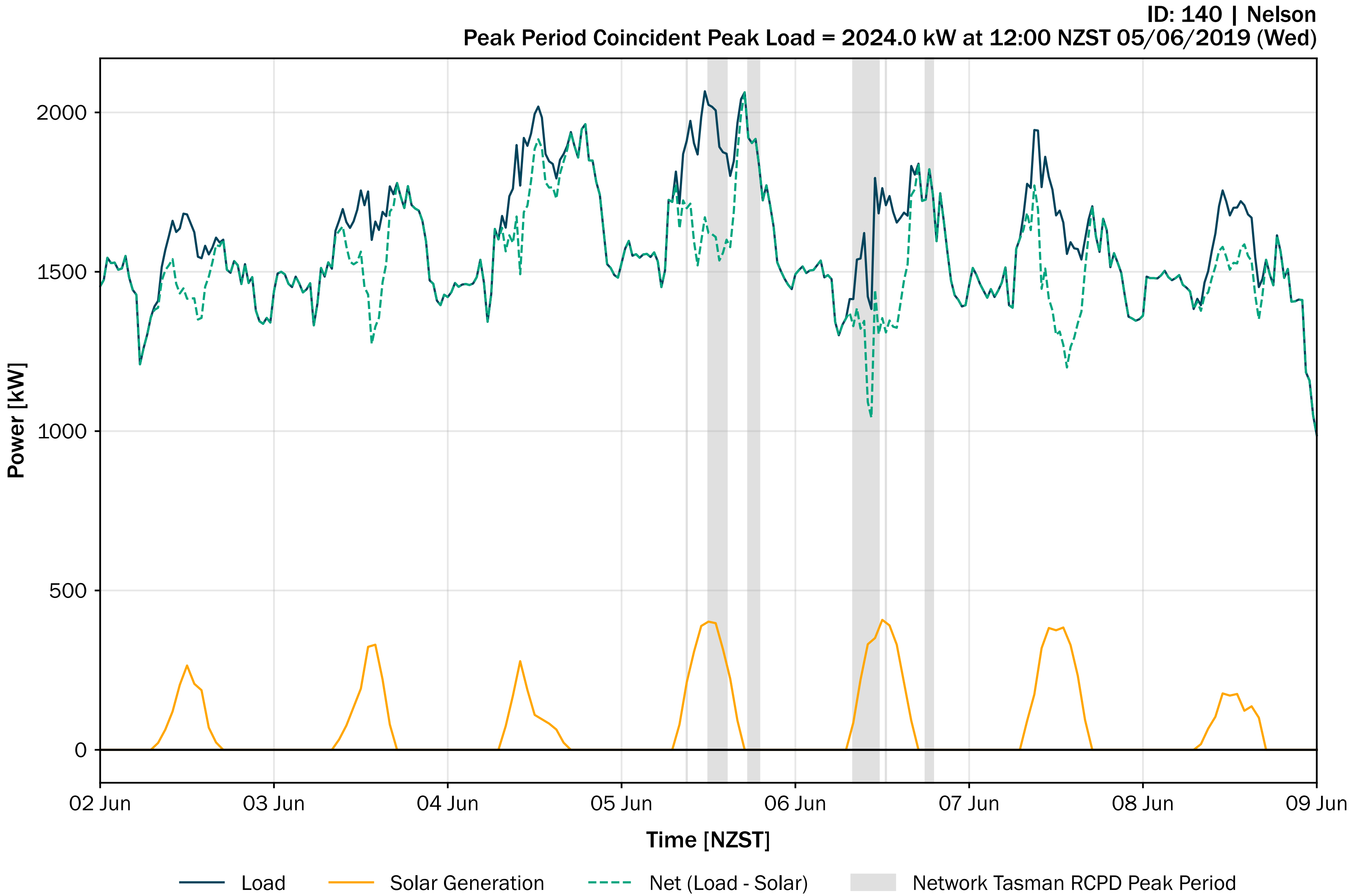


Figure 33: Site 140's load profiles including the time at which the highest kW load occurred coincident with Network Tasman's peak period.

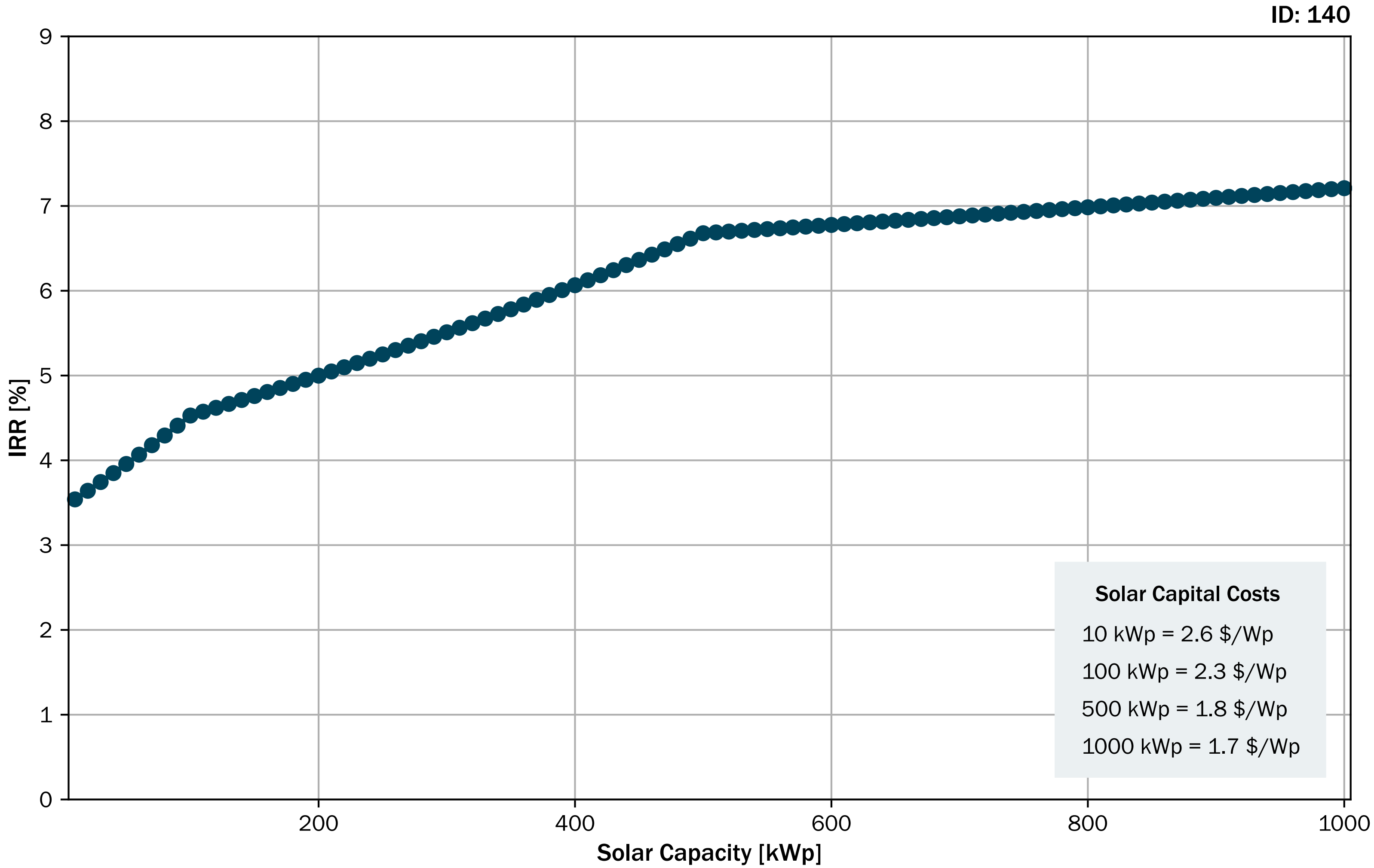


Figure 34: IRR versus solar system capacity for cool store Site 140.

12.5 Corporate office (CO)

The corporate office load type is that of a large office space, incorporating base build and/or tenancy loads.

Figures follow on the next six pages.

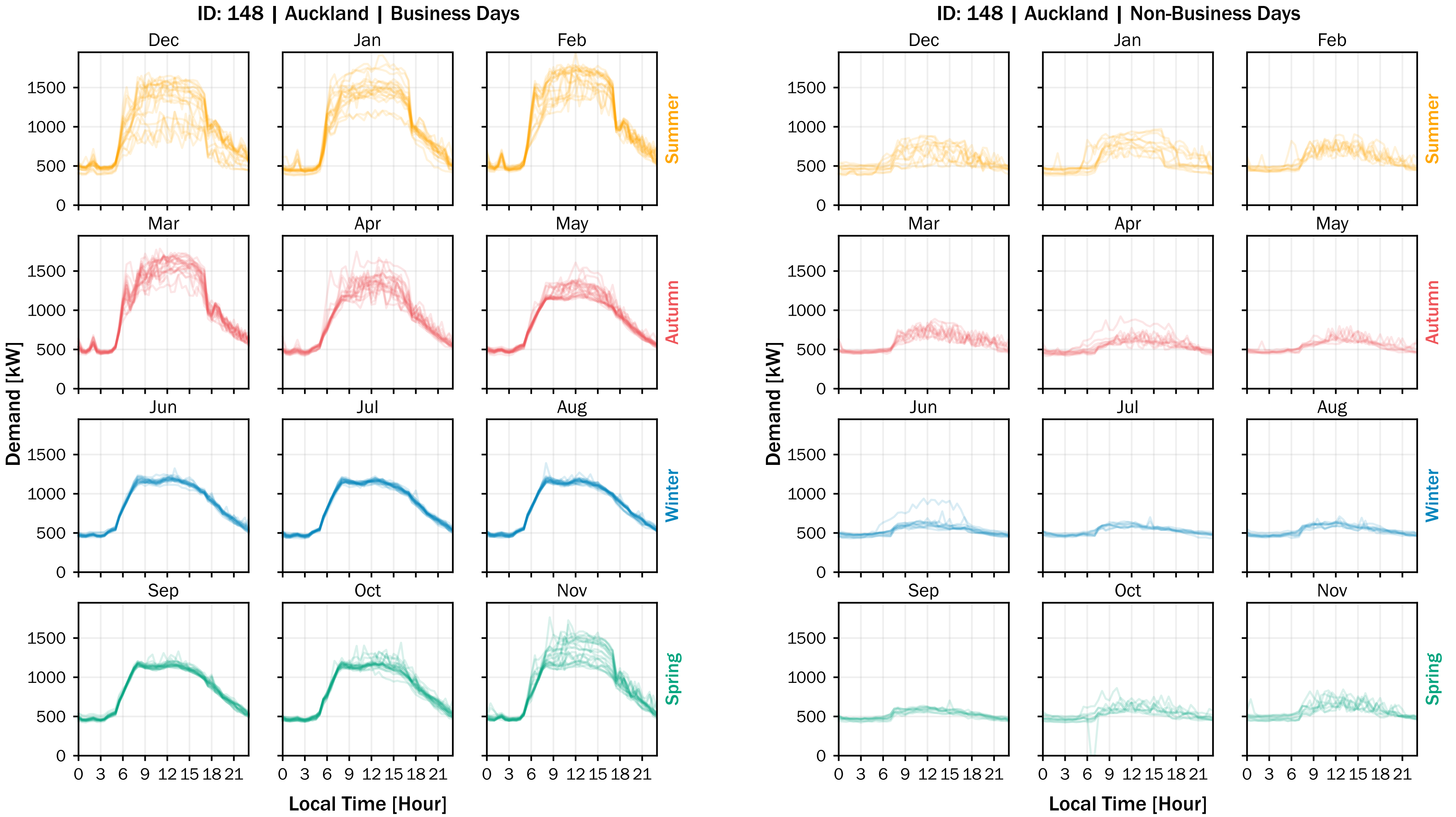
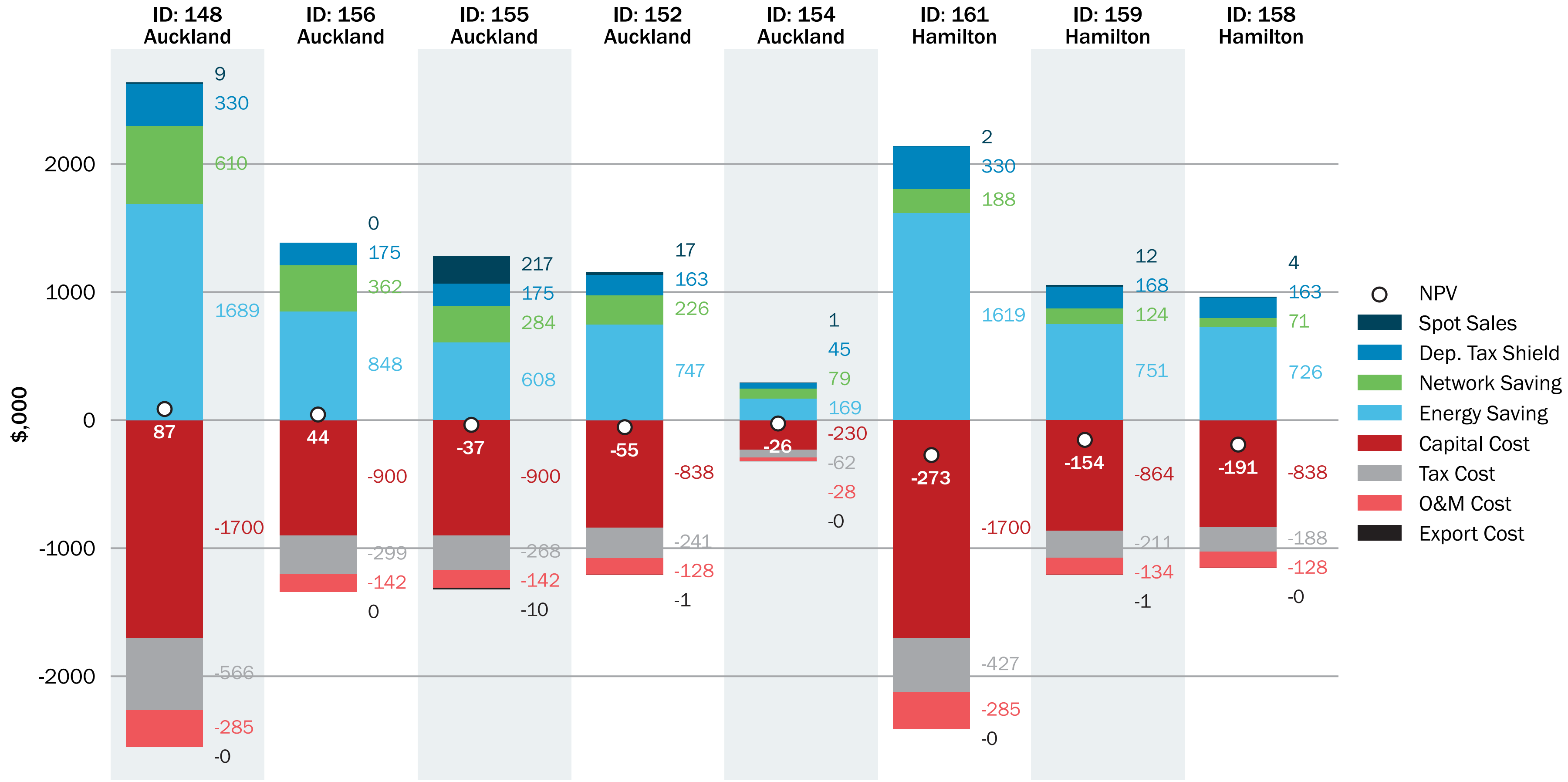


Figure 35: 2019 calendar year load of corporate office Site 148. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



	ID: 148 Auckland	ID: 156 Auckland	ID: 155 Auckland	ID: 152 Auckland	ID: 154 Auckland	ID: 161 Hamilton	ID: 159 Hamilton	ID: 158 Hamilton
IRR	7.6 %	7.6 %	6.5 %	6.2 %	5.6 %	5.0 %	4.8 %	4.1 %
PV	1000 kW	500 kW	500 kW	450 kW	100 kW	1000 kW	470 kW	450 kW
Capacity Factor	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Average Load	800 kW	838 kW	90 kW	172 kW	80 kW	657 kW	187 kW	200 kW
Max Load	1840 kW	2111 kW	600 kW	443 kW	343 kW	1546 kW	468 kW	446 kW
Self Consumption	99.0 %	100.0 %	69.6 %	96.2 %	99.3 %	99.8 %	97.7 %	99.1 %

Figure 36: Financial results of analysis of solar at corporate office Site 148 and another seven sites. Only Site 148 is a corporate office; all other sites are retail sites associated with the same company.

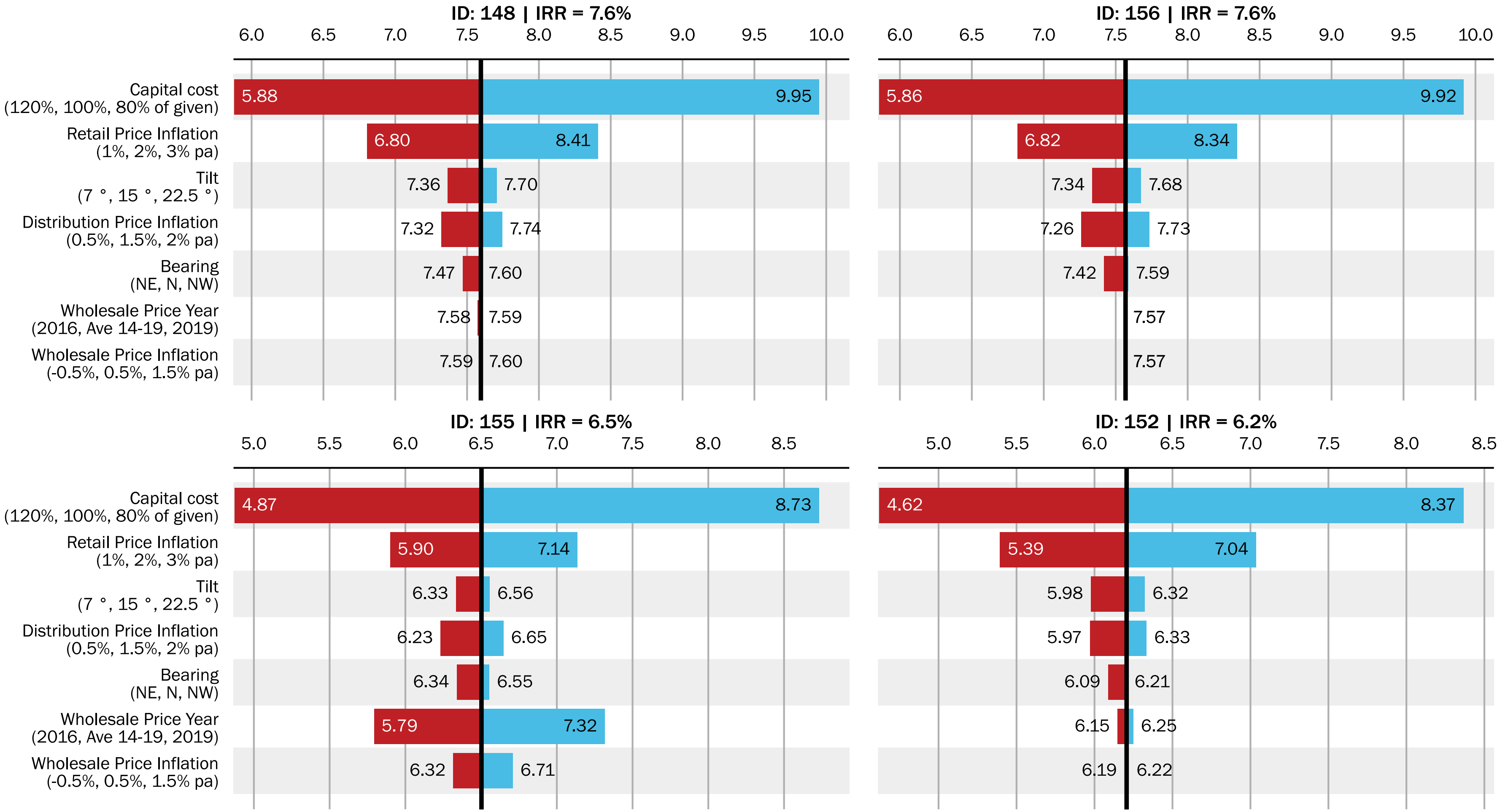


Figure 37: Sensitivity of IRR to inputs for corporate office Site 148 and three other sites.

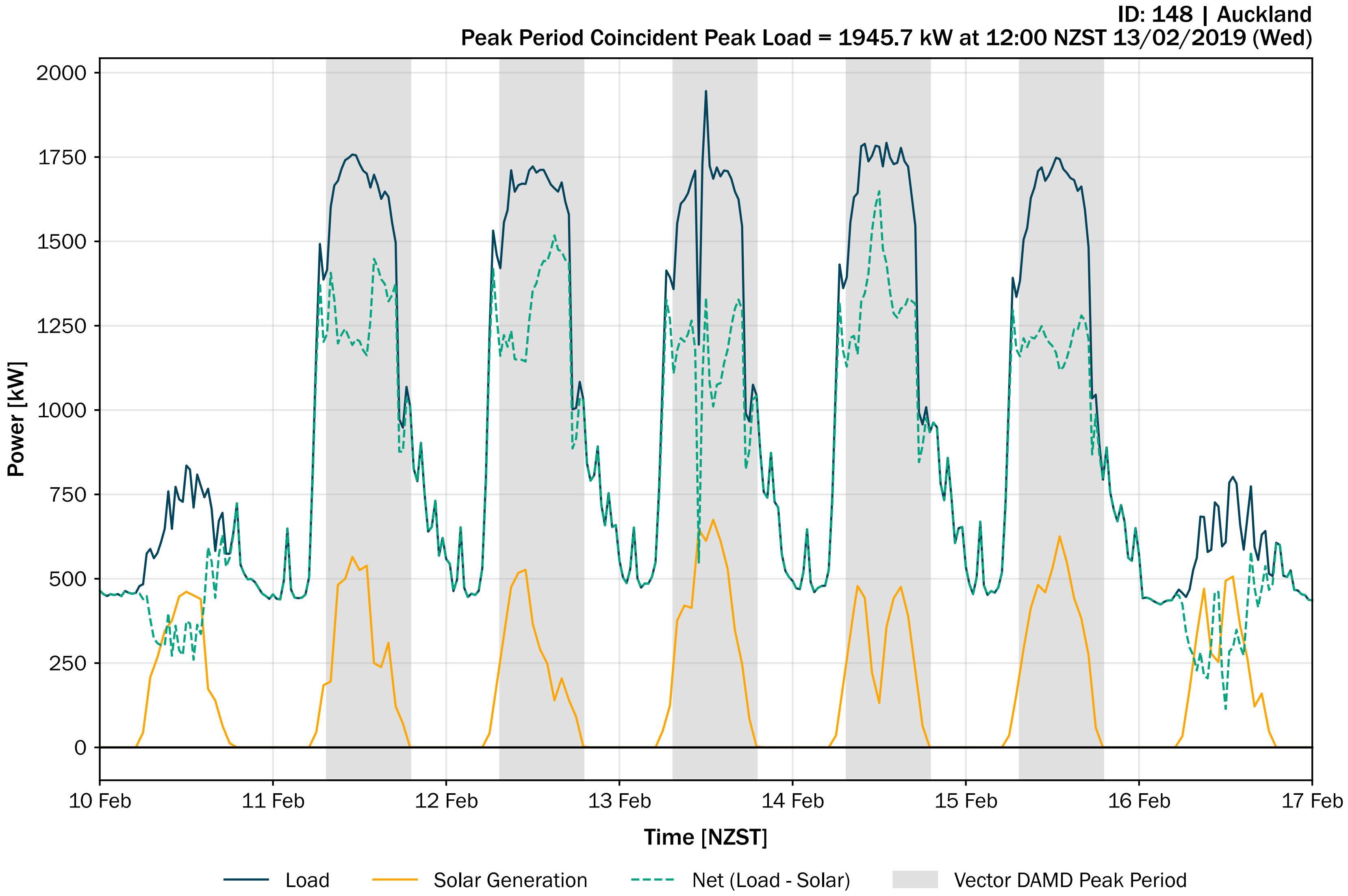


Figure 38: Site 148's load profiles including the time at which the highest kVA load occurred coincident with Vector's peak period.

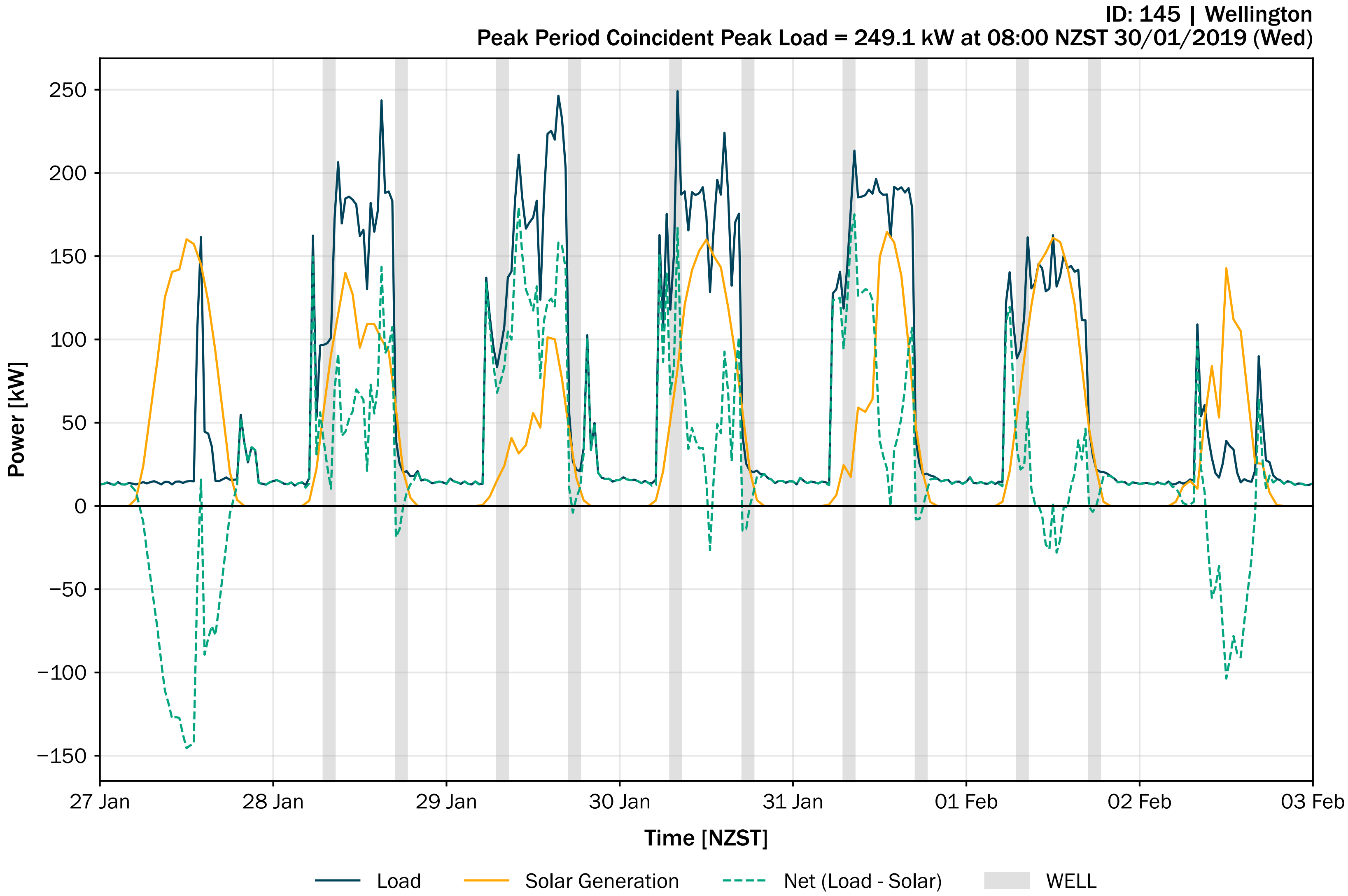


Figure 39: Site 145's load profiles including the time at which the highest kW load occurred coincident with Wellington Electricity's peak period. Site 145 has a low IRR of 2.4 %, with a relatively low network cost saving. This is shown to contrast with Site 148 – even though there is some reduction in load during Wellington Electricity's peak periods, the Customer's size is such that peak charges do not apply, and volume charges are very low with the same charge applying in all time periods.

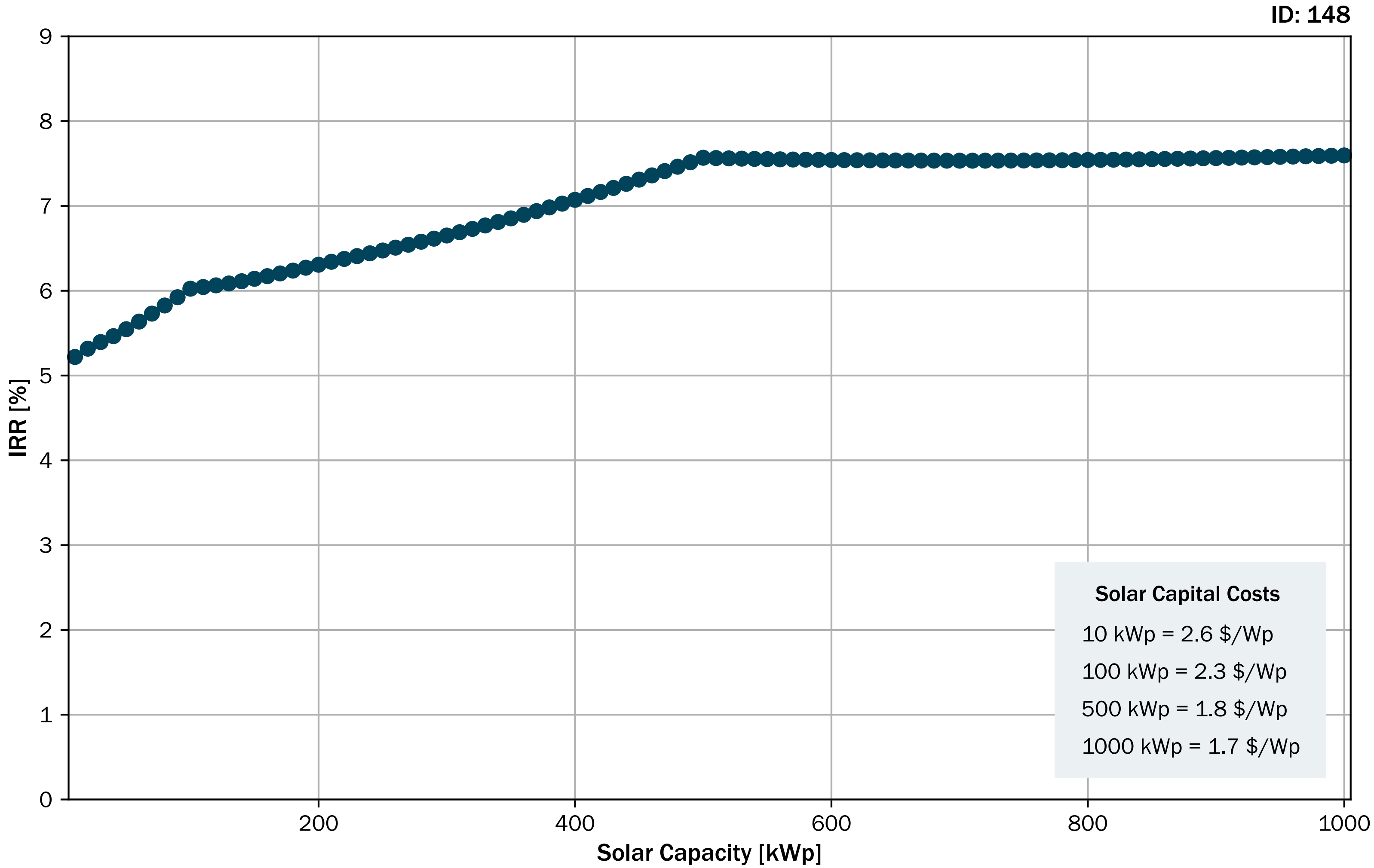


Figure 40: IRR versus solar system capacity for corporate office Site 148.

12.6 Retail warehousing (RW)

The retail warehousing load type is that of warehousing dedicated to a single big box retail brand.

Figures follow on the next five pages.

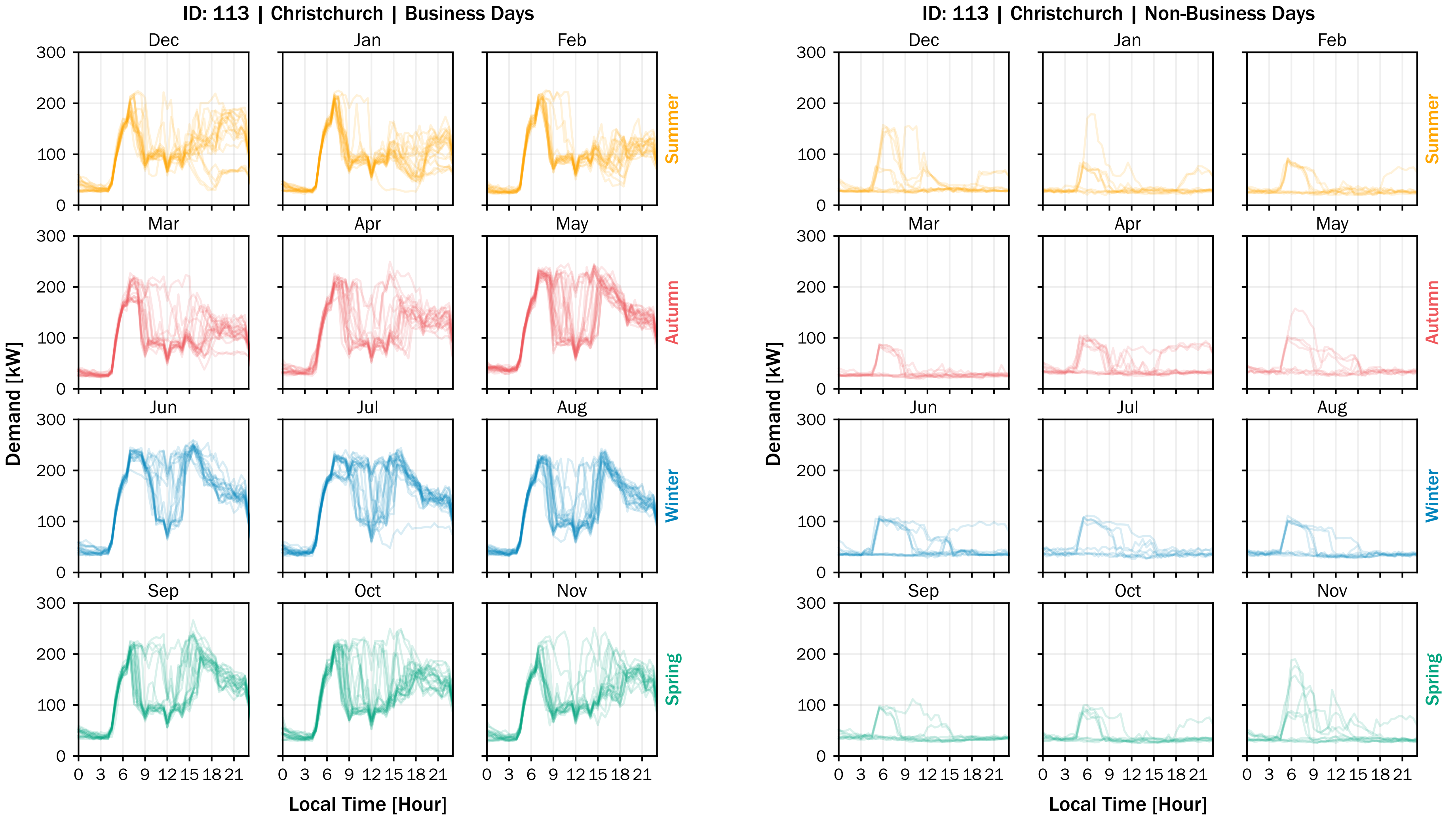
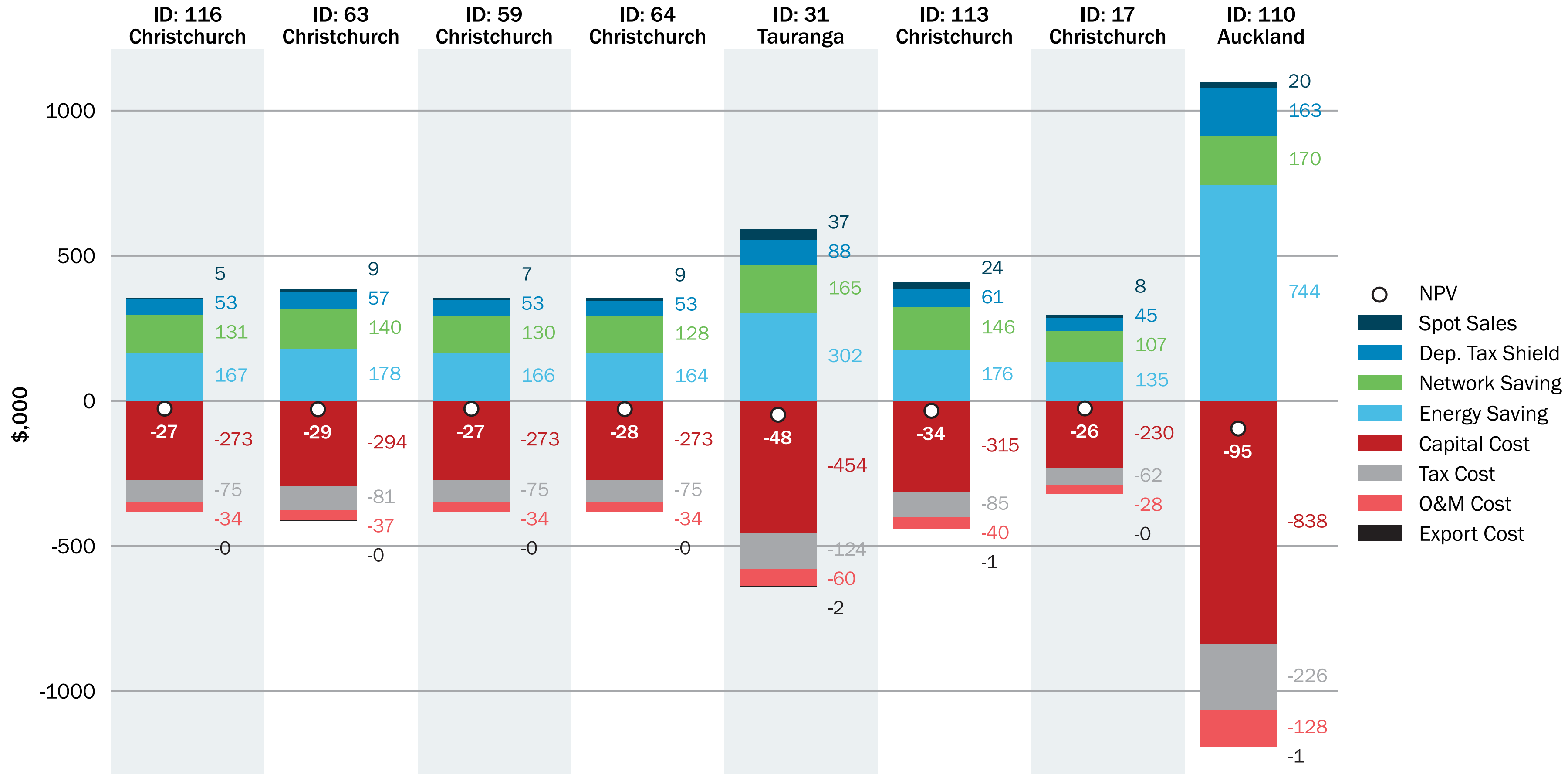


Figure 41: 2019 calendar year load of retail warehousing Site 113. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



IRR	5.8 %	5.8 %	5.8 %	5.7 %	5.7 %	5.7 %	5.6 %	5.6 %
PV	120 kW	130 kW	120 kW	120 kW	210 kW	140 kW	100 kW	450 kW
Capacity Factor	0.14	0.14	0.14	0.14	0.15	0.14	0.14	0.15
Average Load	62 kW	84 kW	67 kW	75 kW	83 kW	92 kW	54 kW	297 kW
Max Load	153 kW	188 kW	190 kW	170 kW	203 kW	256 kW	142 kW	450 kW
Self Consumption	95.6 %	93.7 %	94.7 %	93.2 %	85.4 %	84.0 %	92.2 %	95.8 %

Figure 42: Financial results of analysis of solar at retail warehousing Site 113 (third from right) and another seven sites. Site 110 is also retail warehousing, while other sites have different load types associated with the same company.

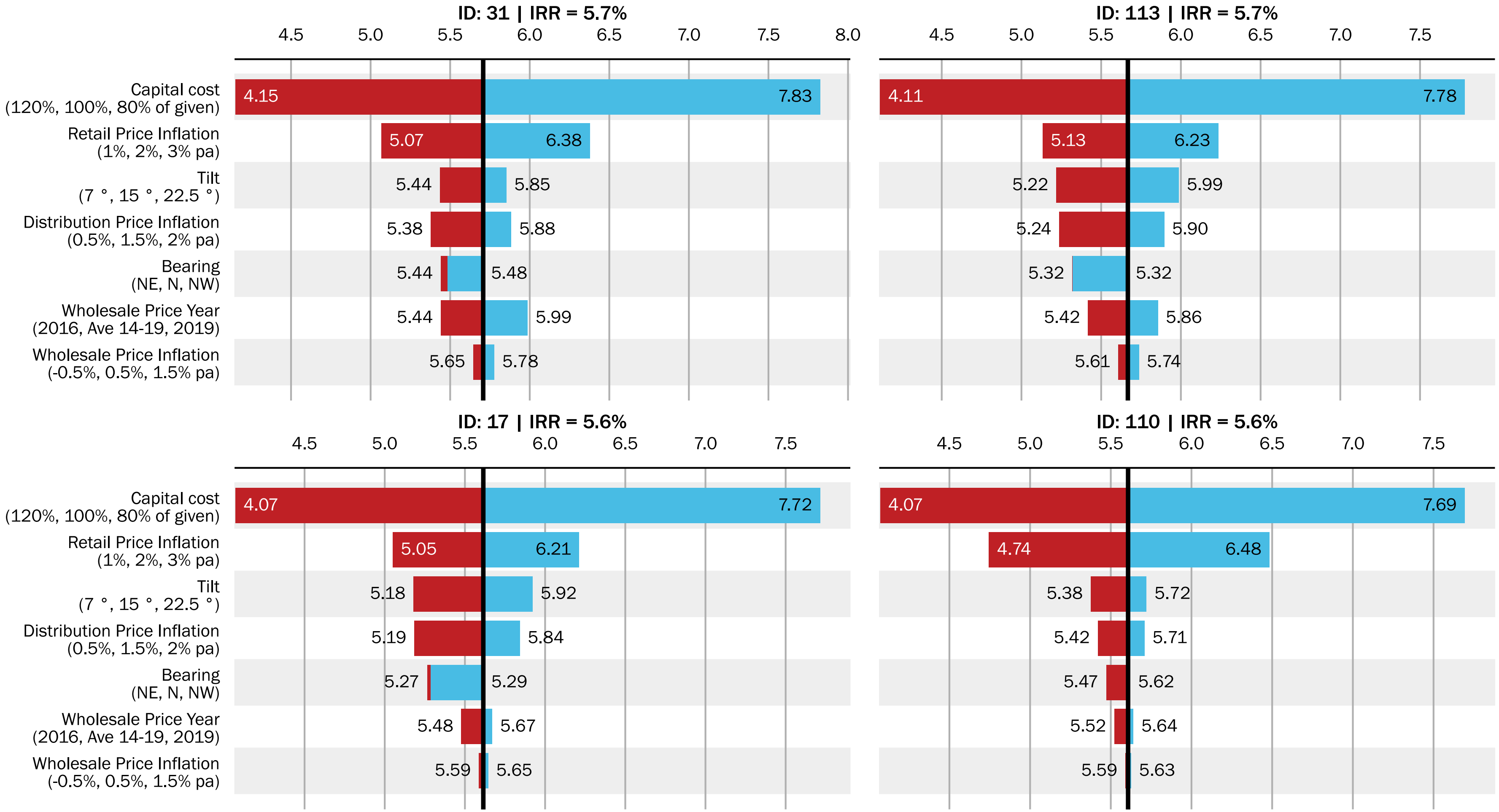


Figure 43: Sensitivity of IRR to inputs for retail warehousing Site 113 and three other sites.

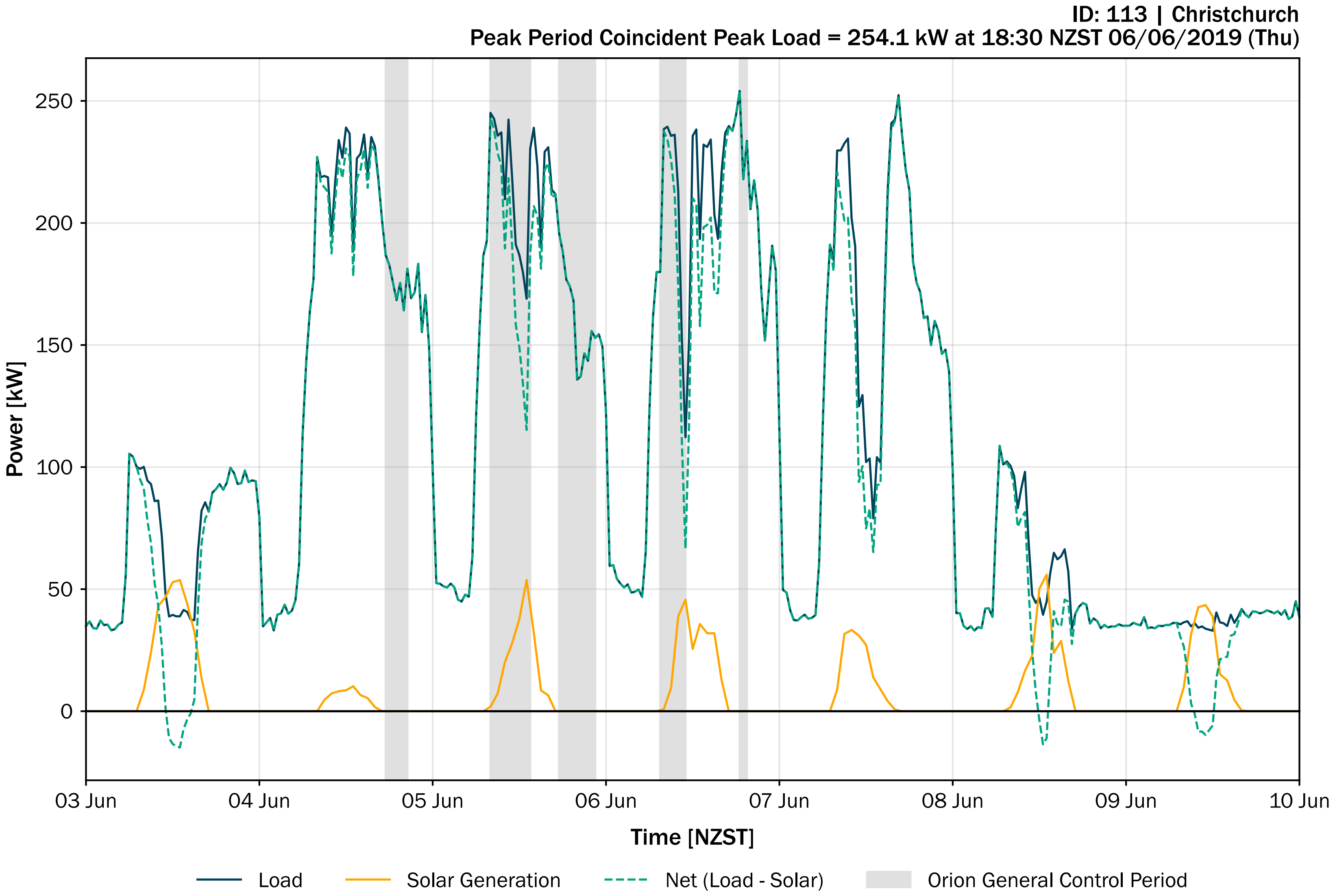


Figure 44: Site 113's load profiles including the time at which the highest kW load occurred coincident with Vector's peak period.

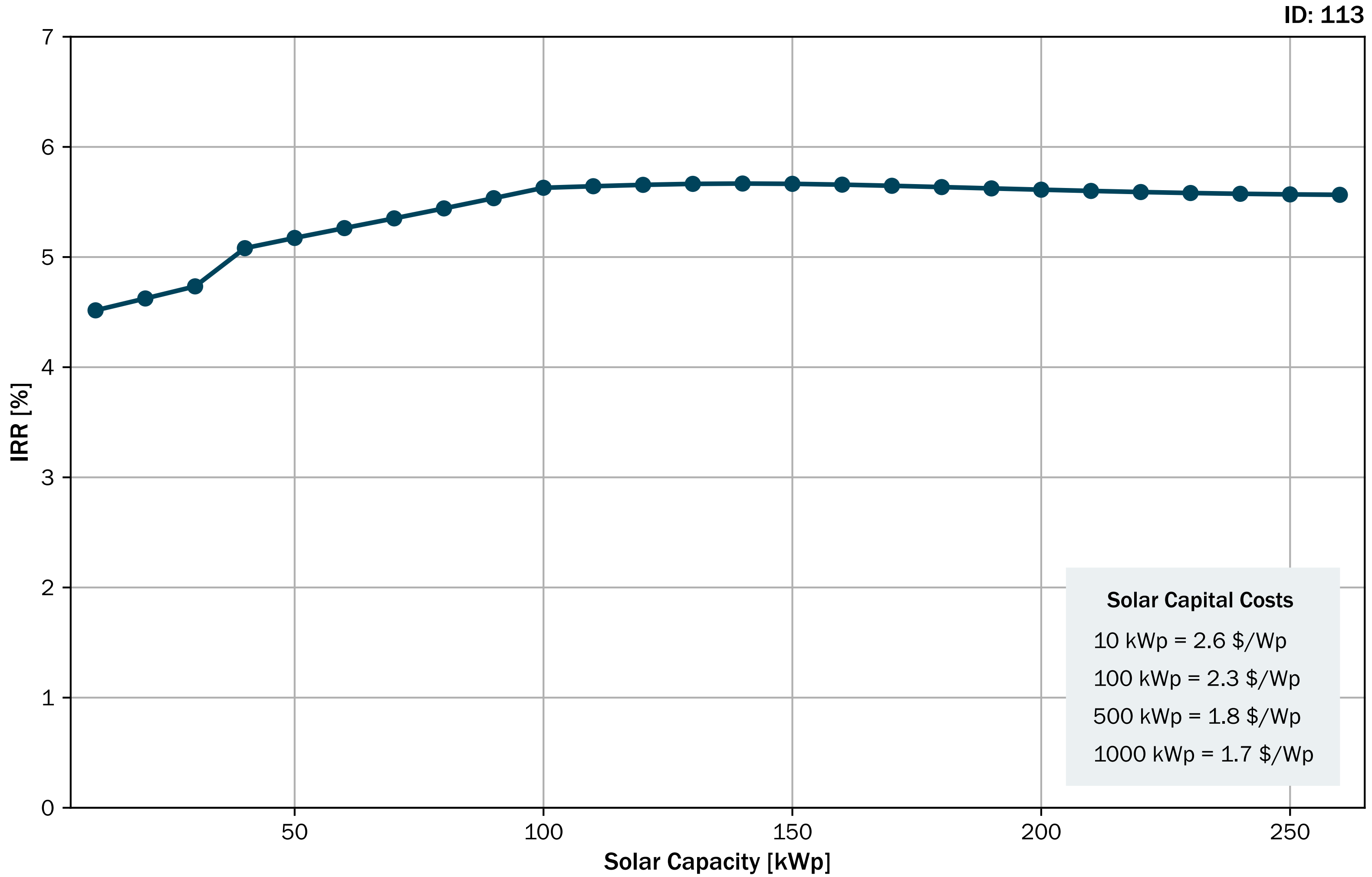


Figure 45: IRR versus solar system capacity for retail warehousing Site 113.

12.7 Warehousing (WHS)

The warehousing load type is that of warehousing by a logistics company, including refrigeration.

Figures follow on the next five pages.

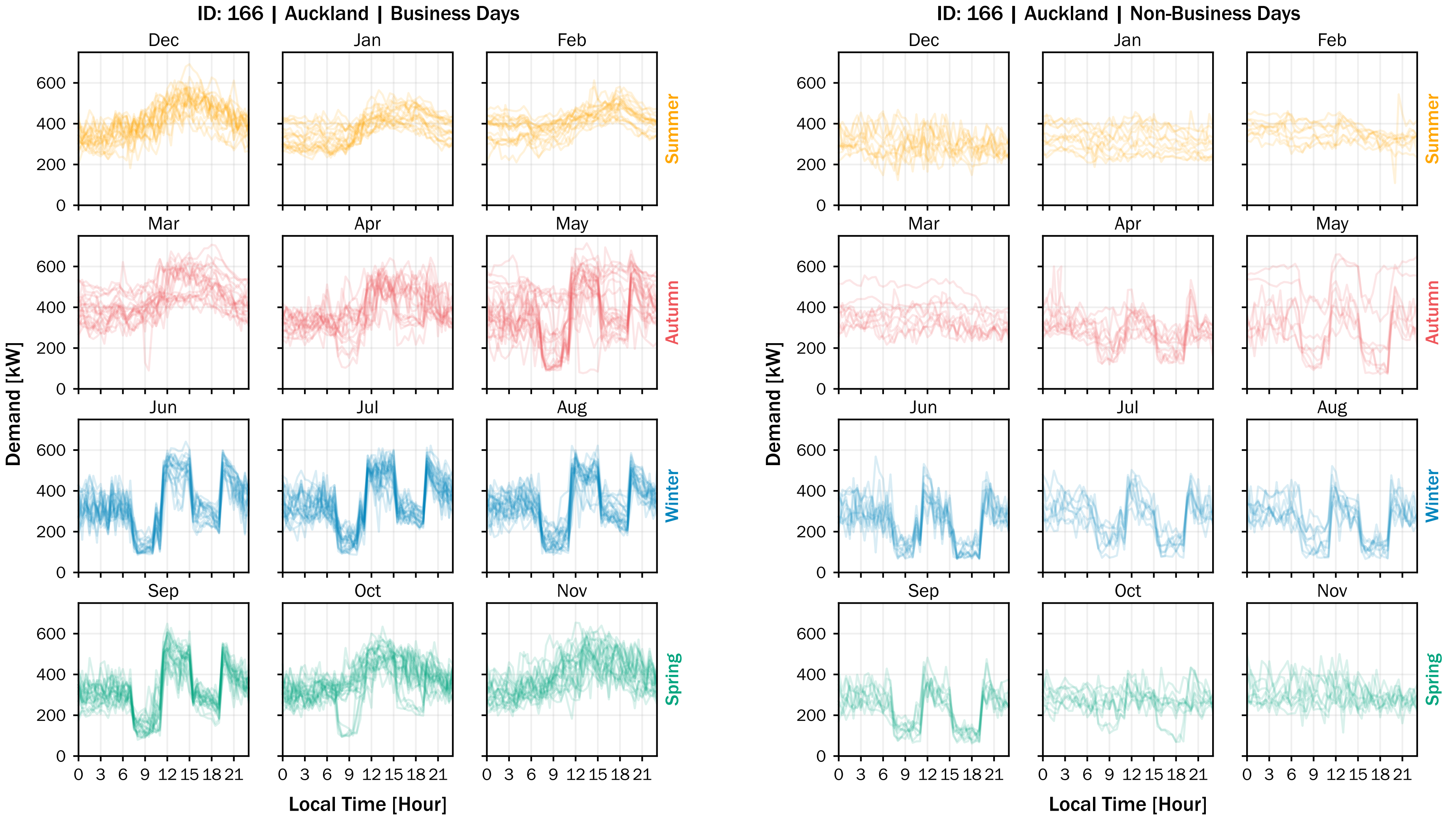
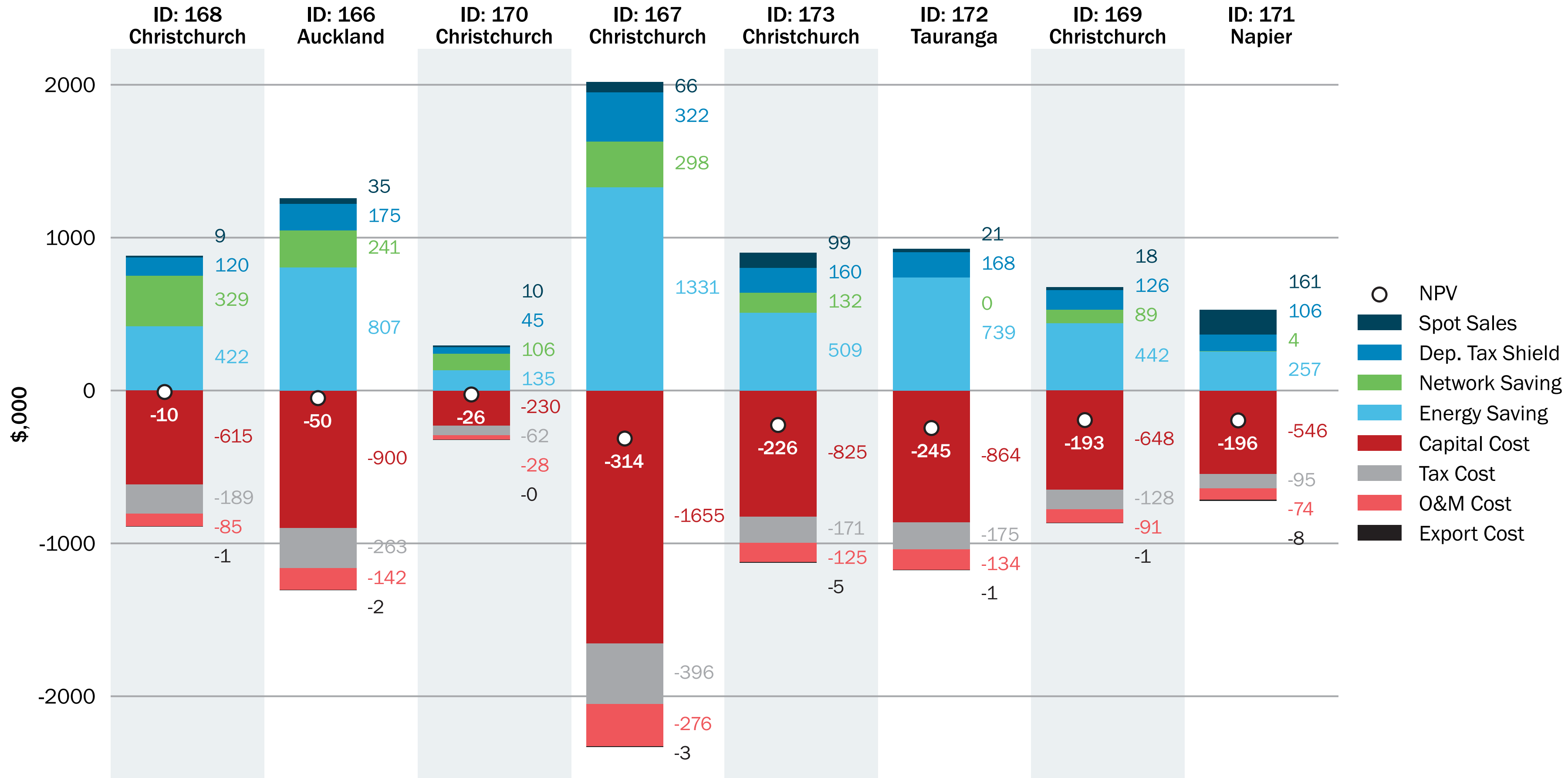


Figure 46: 2019 calendar year load of warehousing Site 166. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



	ID: 168	ID: 166	ID: 170	ID: 167	ID: 173	ID: 172	ID: 169	ID: 171
IRR	6.8 %	6.3 %	5.6 %	4.6 %	3.4 %	3.3 %	3.0 %	2.0 %
PV	300 kW	500 kW	100 kW	970 kW	440 kW	470 kW	320 kW	260 kW
Capacity Factor	0.14	0.15	0.14	0.14	0.14	0.15	0.14	0.16
Average Load	182 kW	350 kW	53 kW	561 kW	186 kW	279 kW	187 kW	101 kW
Max Load	298 kW	701 kW	96 kW	970 kW	432 kW	465 kW	312 kW	258 kW
Self Consumption	96.5 %	94.0 %	90.8 %	93.0 %	80.2 %	95.5 %	94.5 %	58.1 %

Figure 47: Financial results of analysis of solar at warehousing Site 166 and another seven sites.

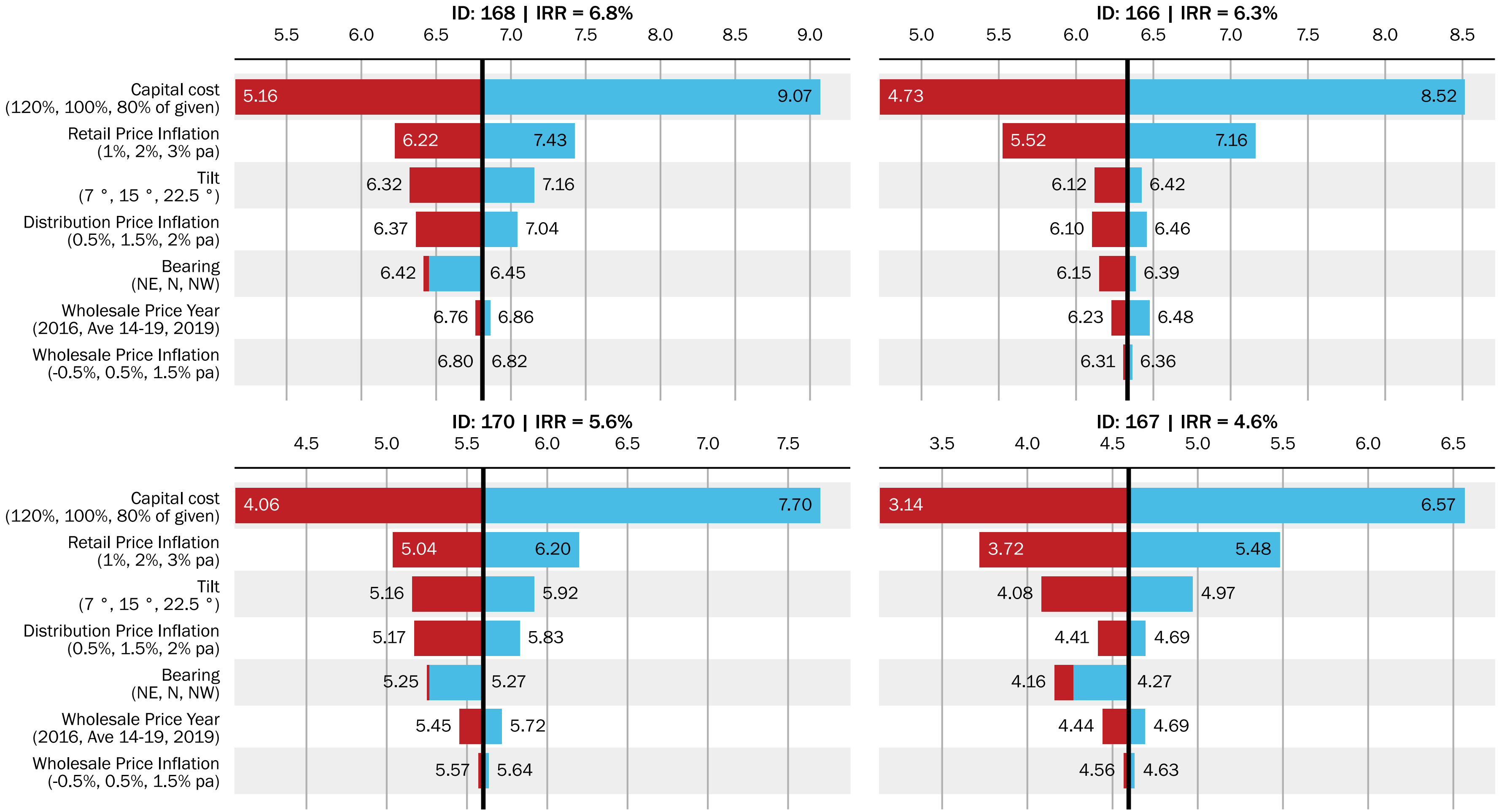


Figure 48: Sensitivity of IRR to inputs for warehousing Site 166 and three other sites.

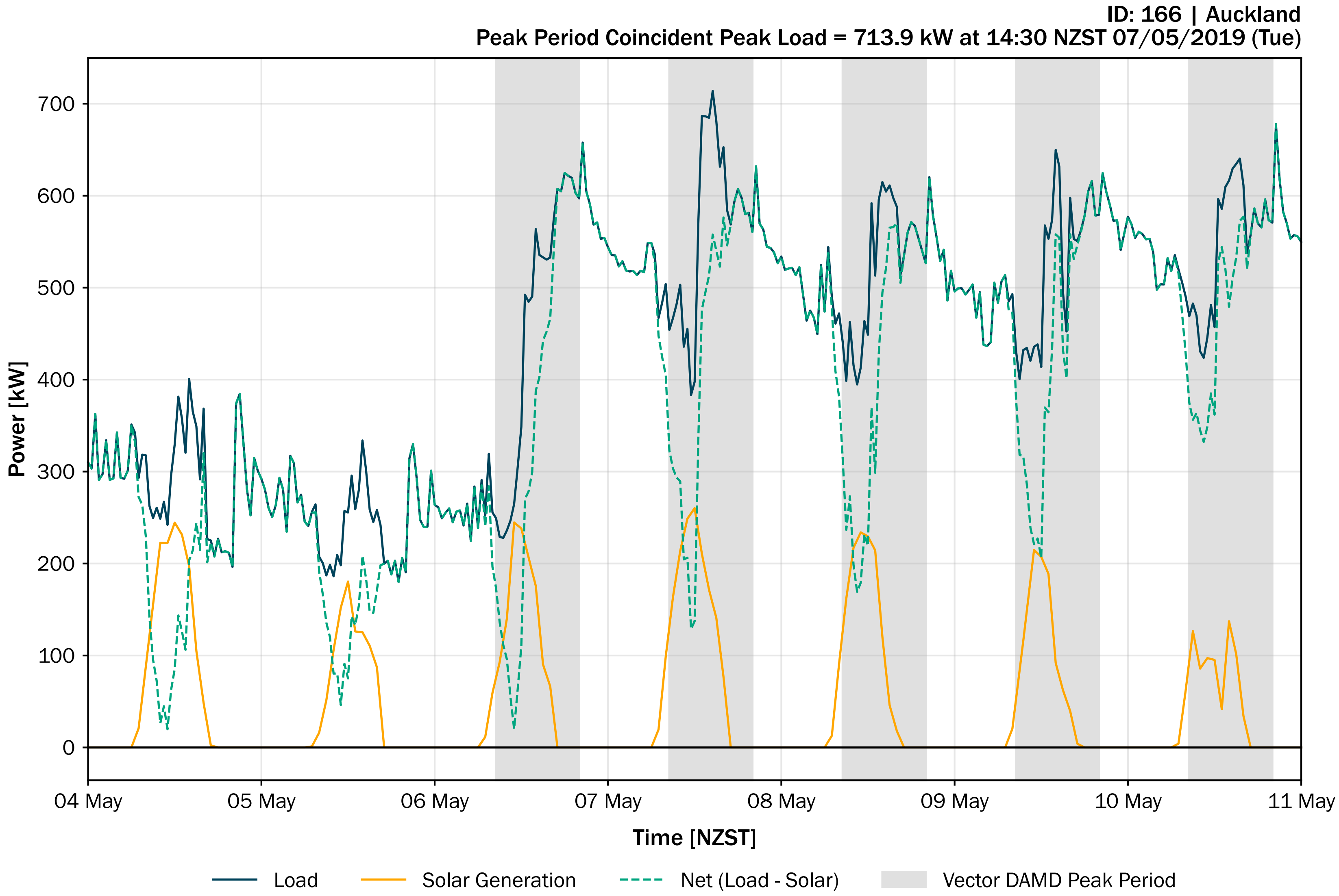


Figure 49: Site 166's load profiles including the time at which the highest kVA load occurred coincident with Vector's peak period.

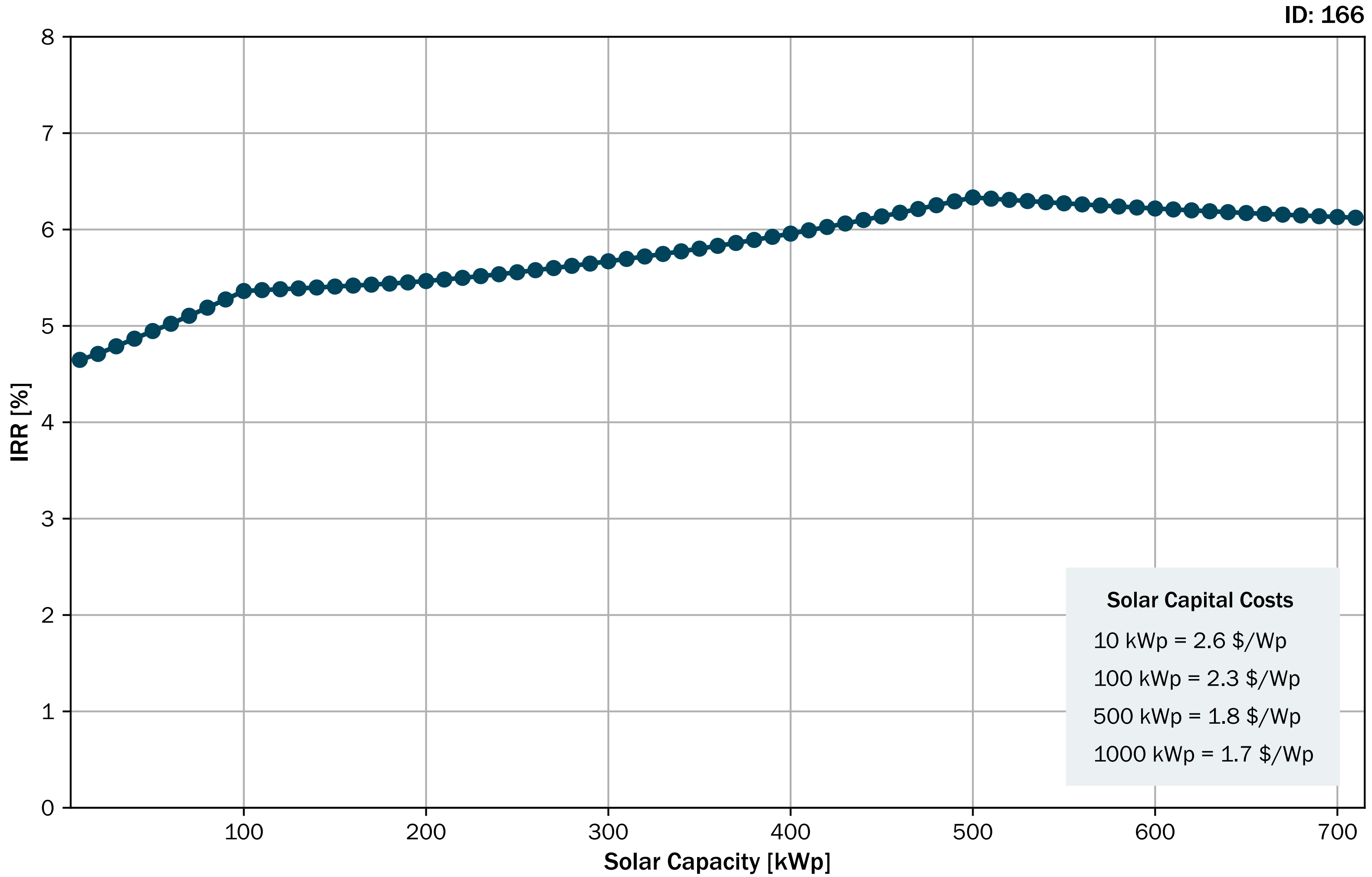


Figure 50: IRR versus solar system capacity for retail Site 166.

12.8 Production (Prod)

The production load type is that of food and beverage production.

Figures follow on the next five pages.

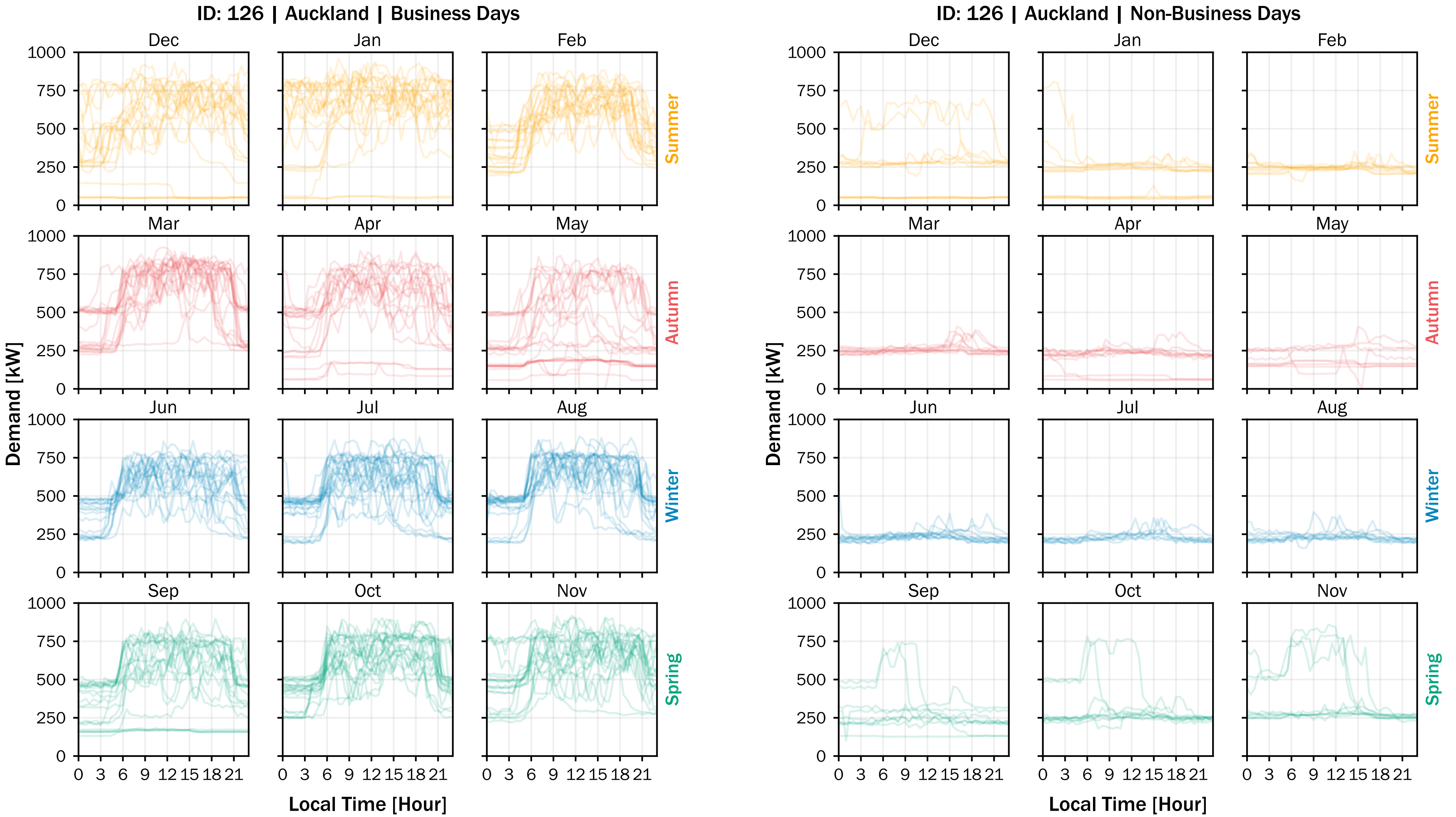
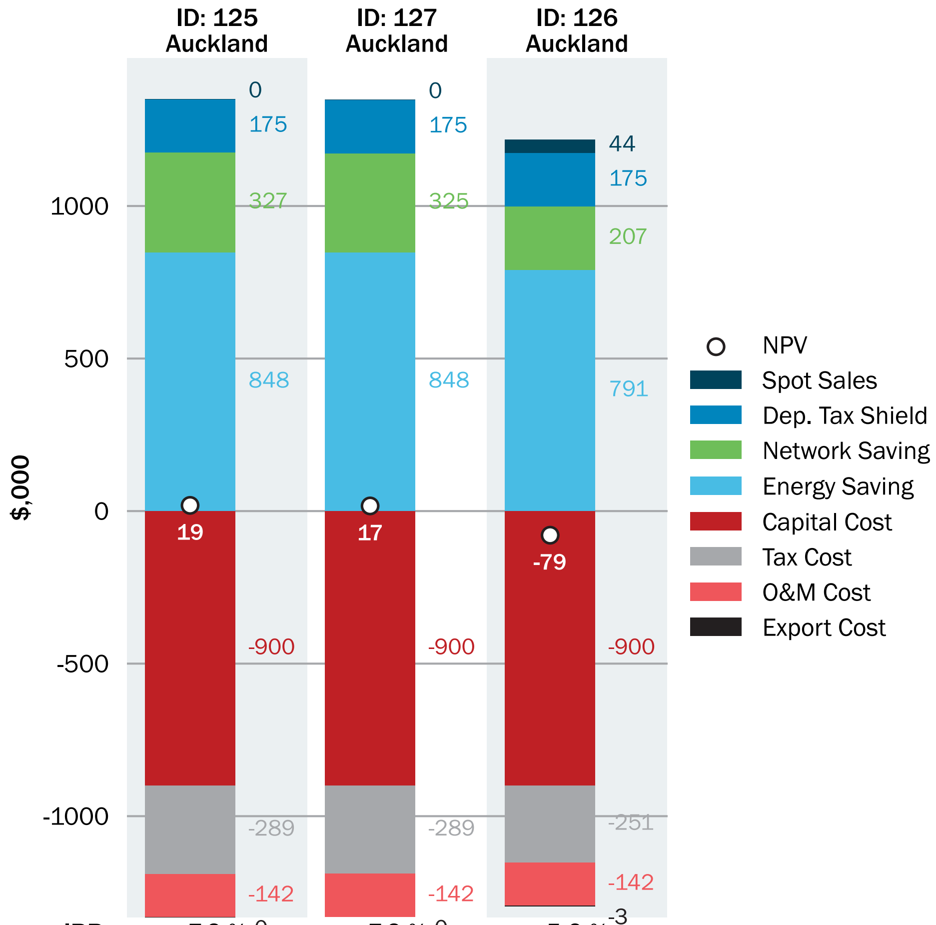


Figure 51: 2019 calendar year load of production Site 126. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



	ID: 125	ID: 127	ID: 126
IRR	7.2 %	7.2 %	5.9 %
PV	500 kW	500 kW	500 kW
Capacity Factor	0.15	0.15	0.15
Average Load	1221 kW	1664 kW	442 kW
Max Load	2447 kW	3244 kW	930 kW
Self Consumption	99.9 %	100.0 %	91.8 %

Figure 52: Financial results of analysis of solar at production Site 126. This site was chosen as it is the only site which is limited to the production load type. Site 127 combines production and corporate office load types, while Site 125 is a corporate office.

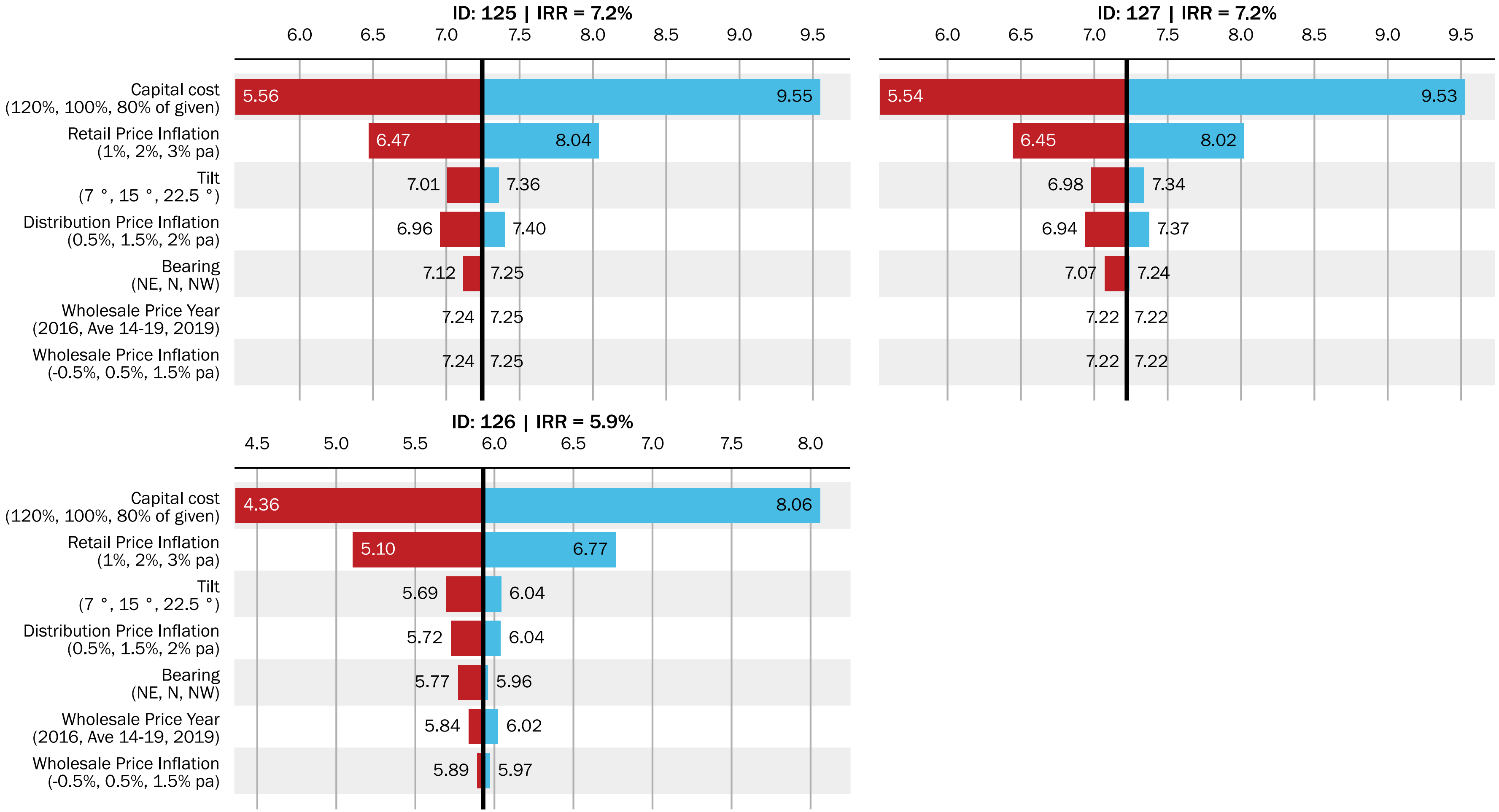


Figure 53: Sensitivity of IRR to inputs for production Site 126 and two other sites.

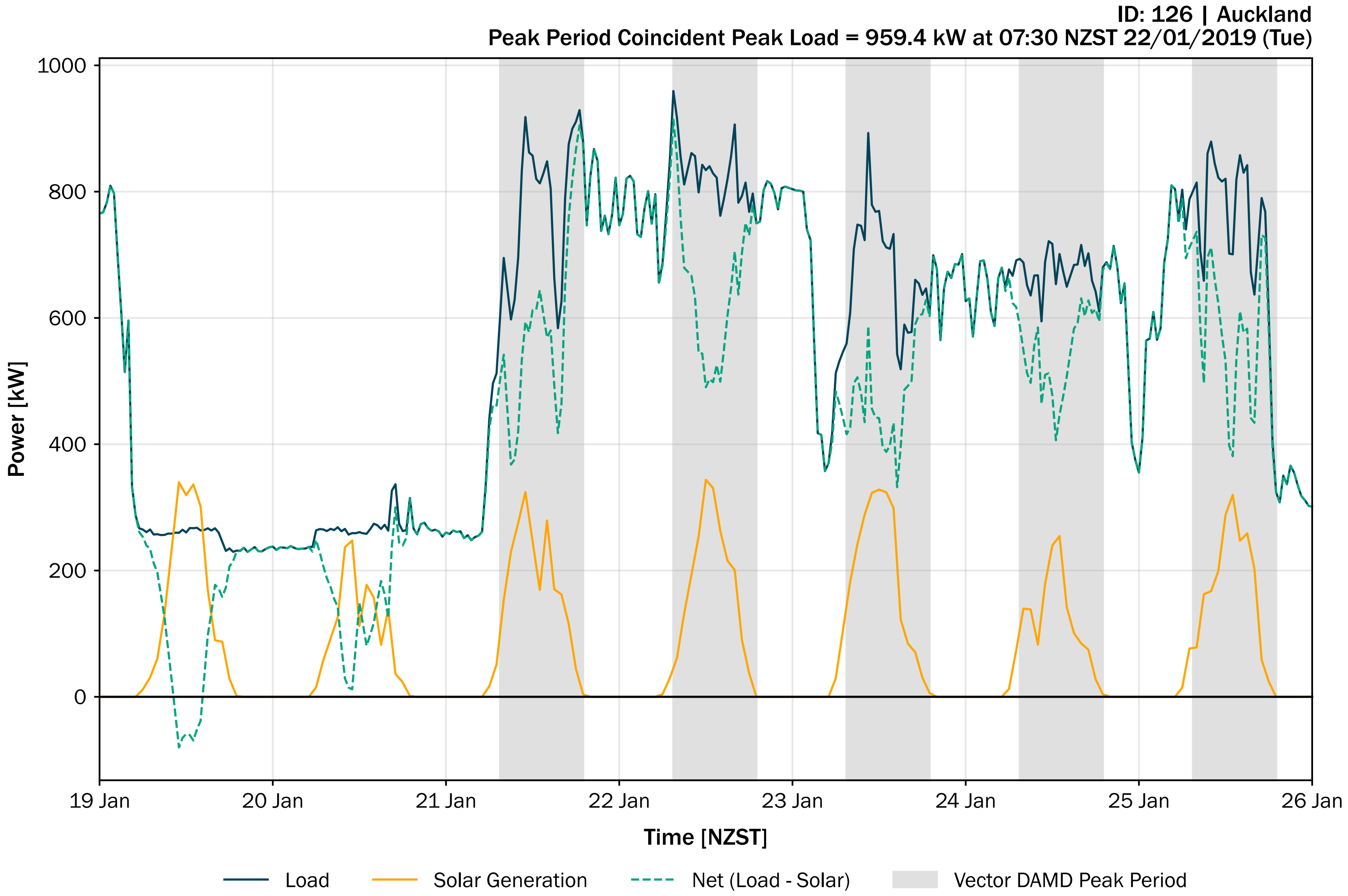


Figure 54: Site 126's load profiles including the time at which the highest kVA load occurred coincident with Vector's peak period.

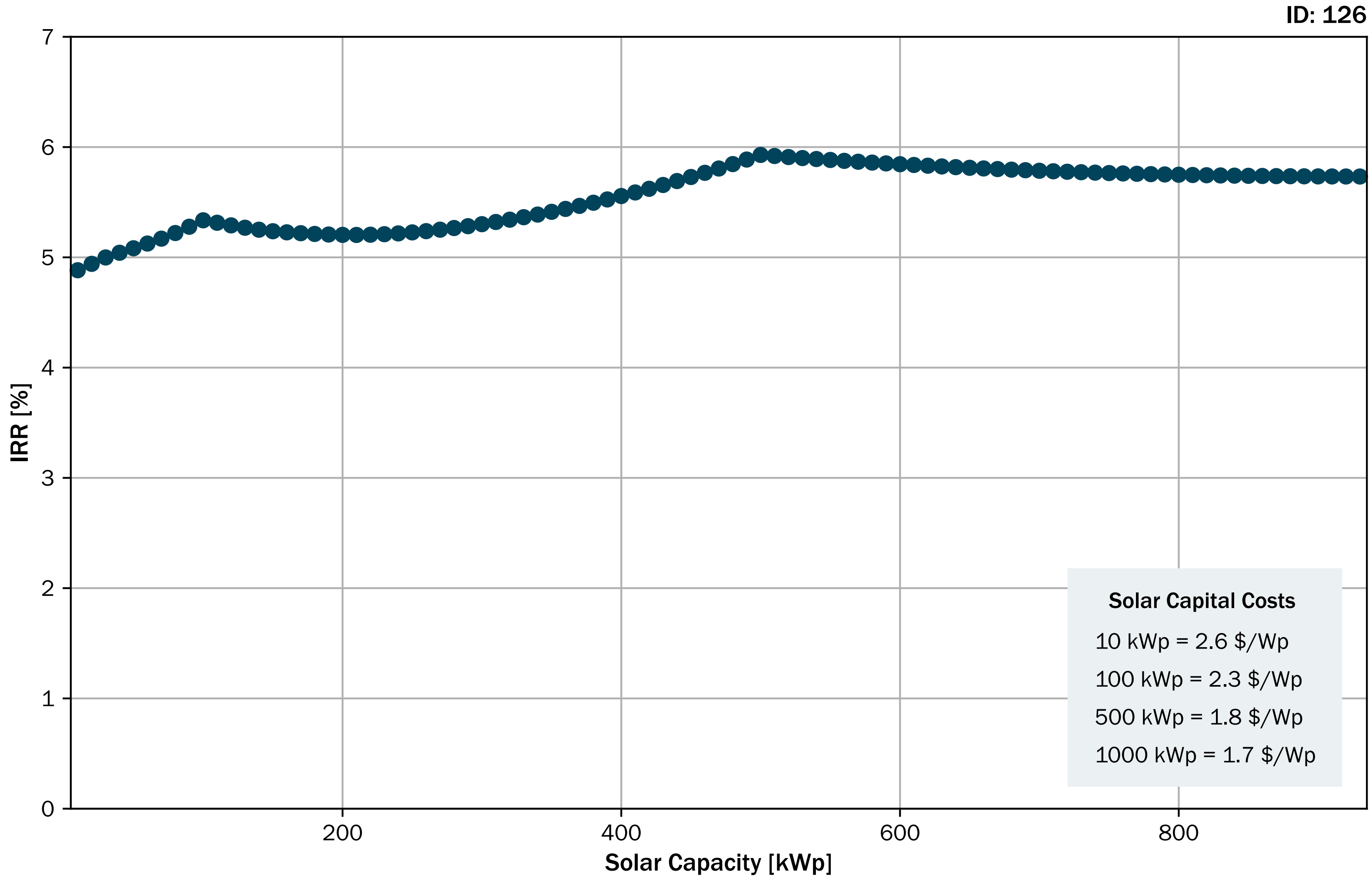


Figure 55: IRR versus solar system capacity for production Site 126.

12.9 Manufacturing (MANU)

The manufacturing load type is that of engineering and product manufacturing.

Figures follow on the next five pages.

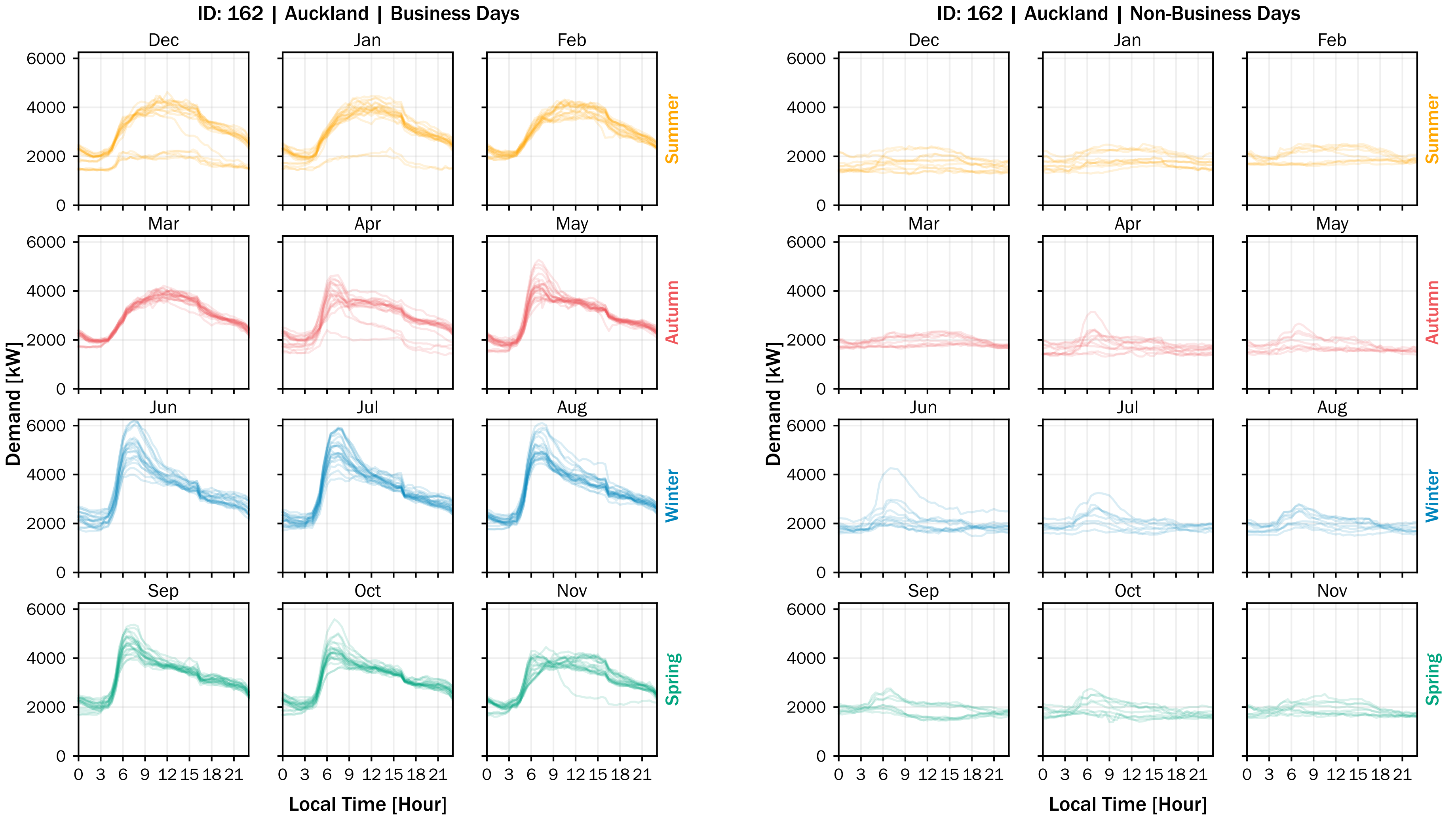
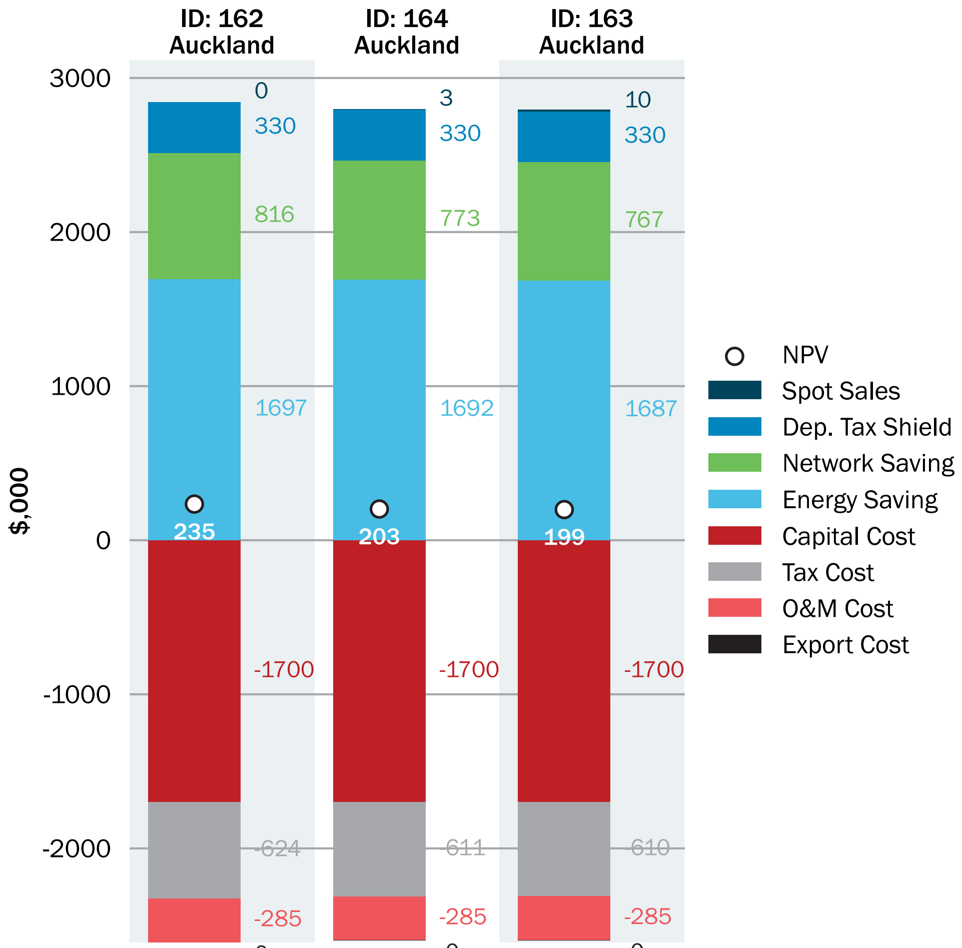


Figure 56: 2019 calendar year load of manufacturing Site 162. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



IRR	8.6 %	8.4 %	8.3 %
PV	1000 kW	1000 kW	1000 kW
Capacity Factor	0.15	0.15	0.15
Average Load	2706 kW	1474 kW	1232 kW
Max Load	6125 kW	4244 kW	3195 kW
Self Consumption	100.0 %	99.7 %	99.4 %

Figure 57: Financial results of analysis of solar at manufacturing Site 162 – the other two sites are separate meters at the same site measuring roughly half the load each.

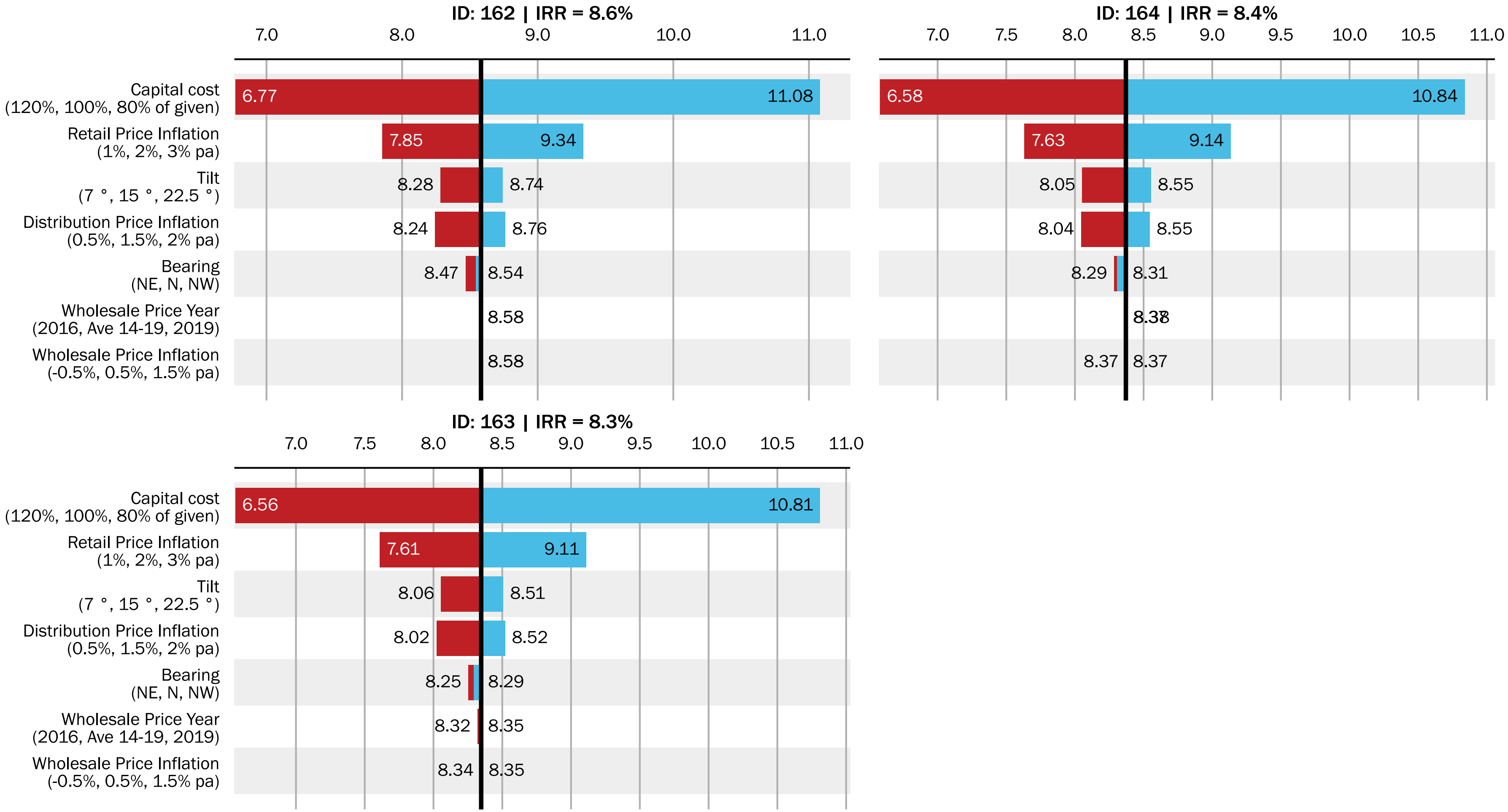


Figure 58: Sensitivity of IRR to inputs for manufacturing Site 162.

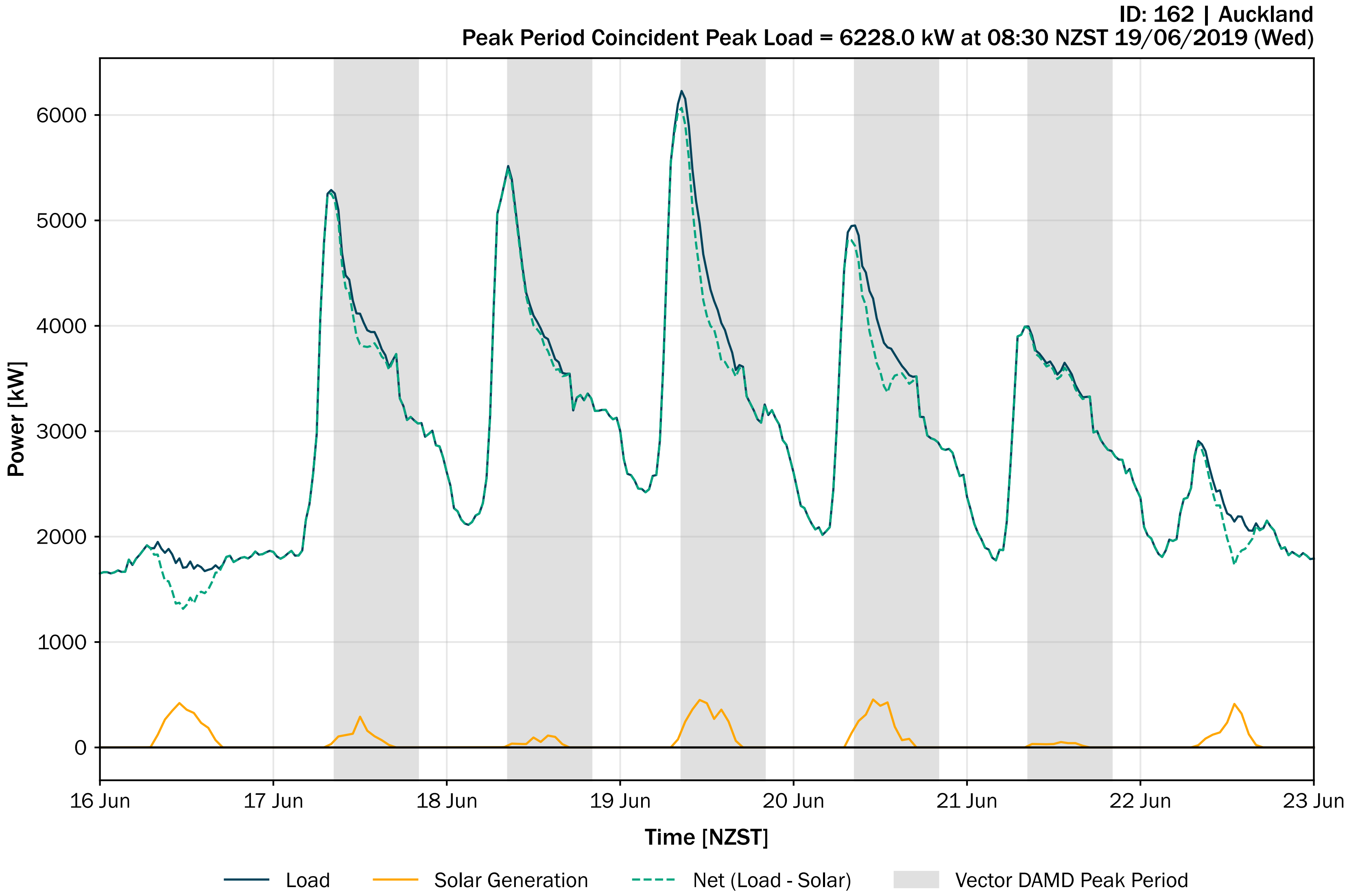


Figure 59: Site 162's load profiles including the time at which the highest kVA load occurred coincident with Vector's peak period.

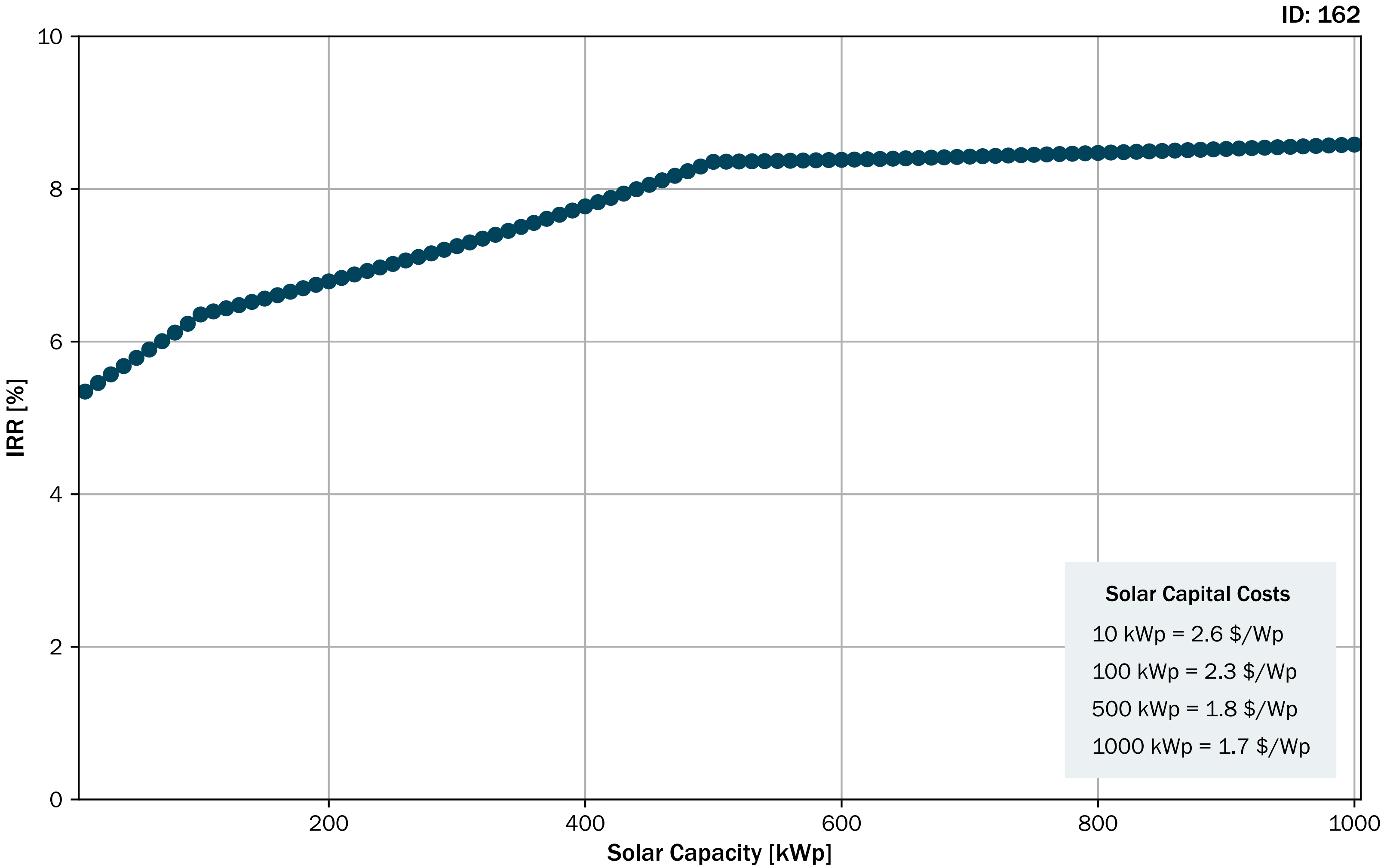


Figure 60: IRR versus solar system capacity for manufacturing Site 162.

12.10 Education (EDU)

The education load type is that of tertiary education building.

Figures follow on the next five pages.

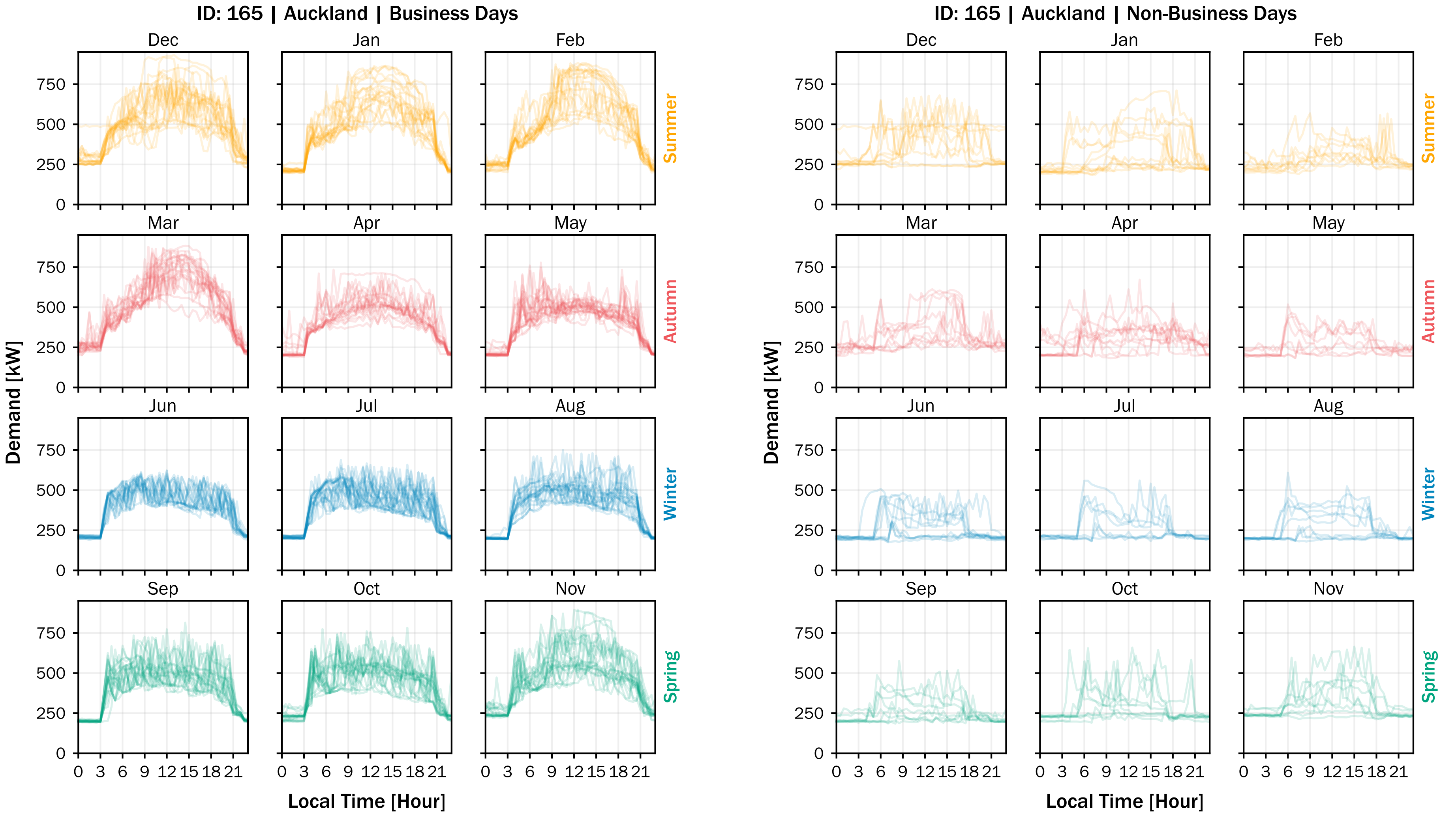
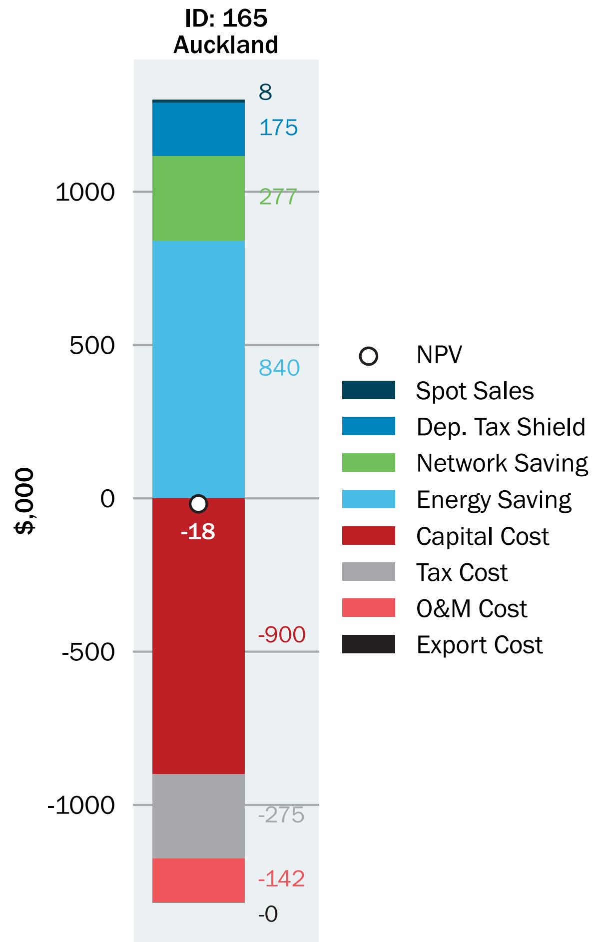


Figure 61: 2019 calendar year load of education Site 165. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



IRR	6.8 %
PV	500 kW
Capacity Factor	0.15
Average Load	391 kW
Max Load	969 kW
Self Consumption	98.4 %

Figure 62: Financial results of analysis of solar at education Site 165.

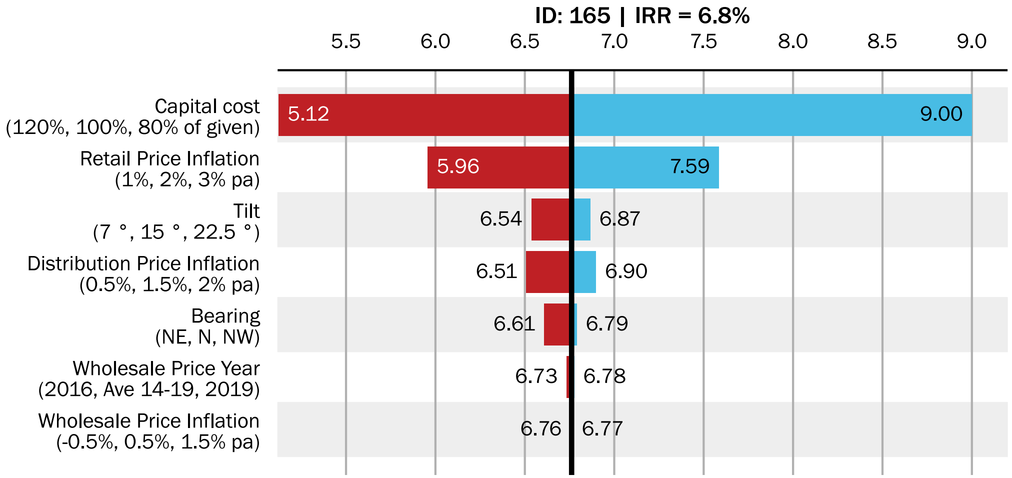


Figure 63: Sensitivity of IRR to inputs for education Site 165.

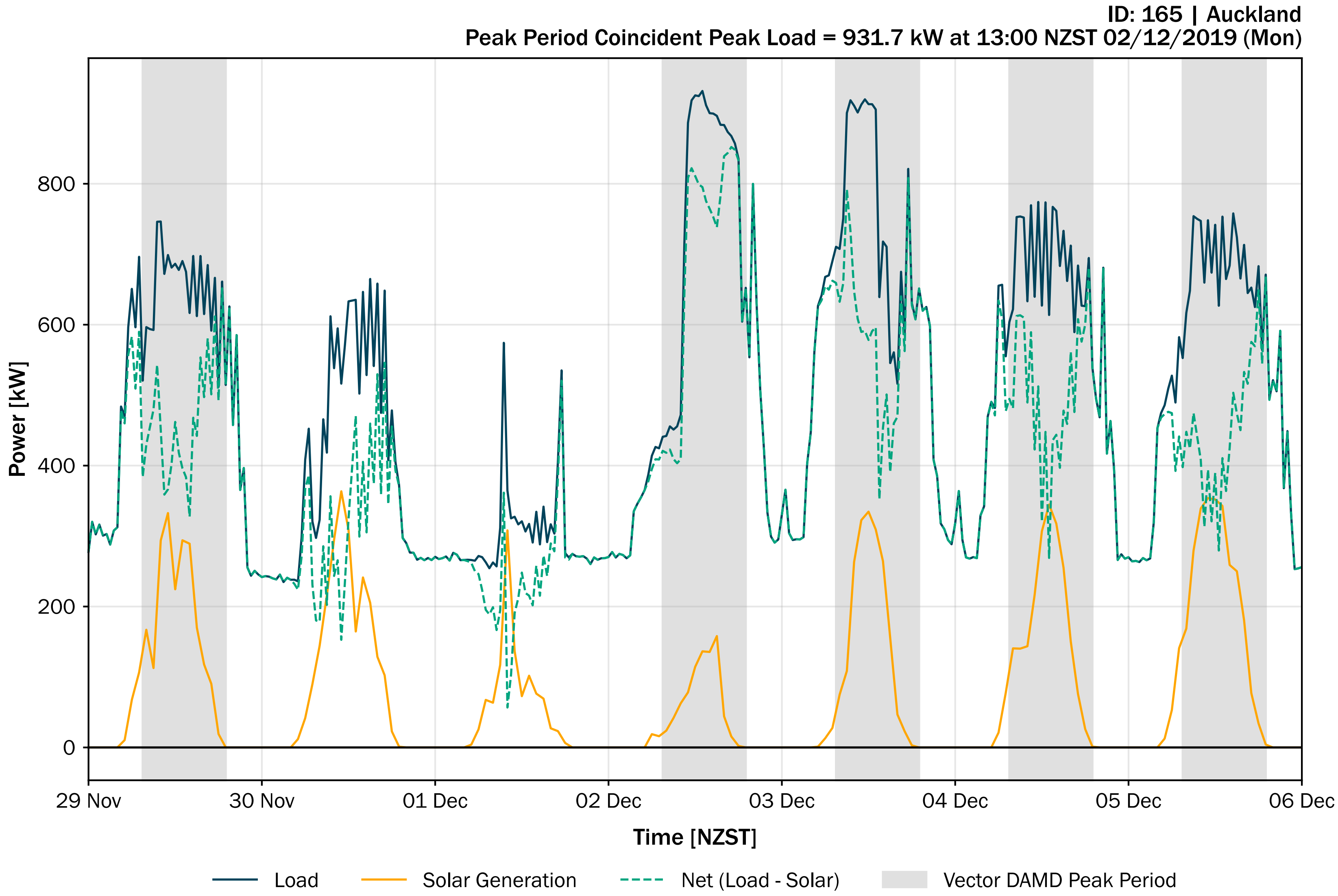


Figure 64: Site 165's load profiles including the time at which the highest kVA load occurred coincident with Vector's peak period.

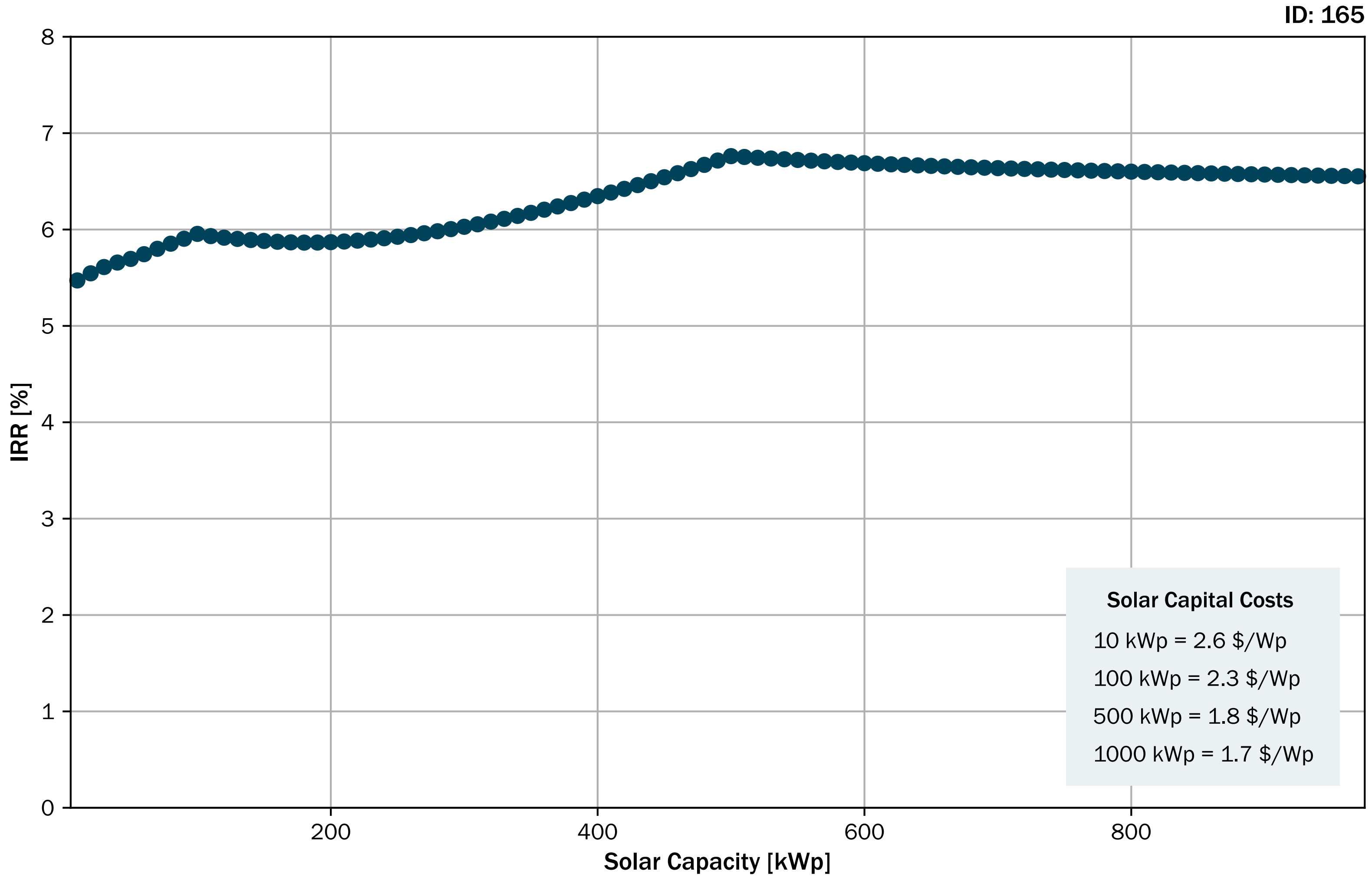


Figure 65: IRR versus solar system capacity for education Site 165.

12.11 Waste water treatment (WWT) and water supply (WS)

The waste water treatment and water supply load types are those associated with water infrastructure.

Figures follow on the next five pages.

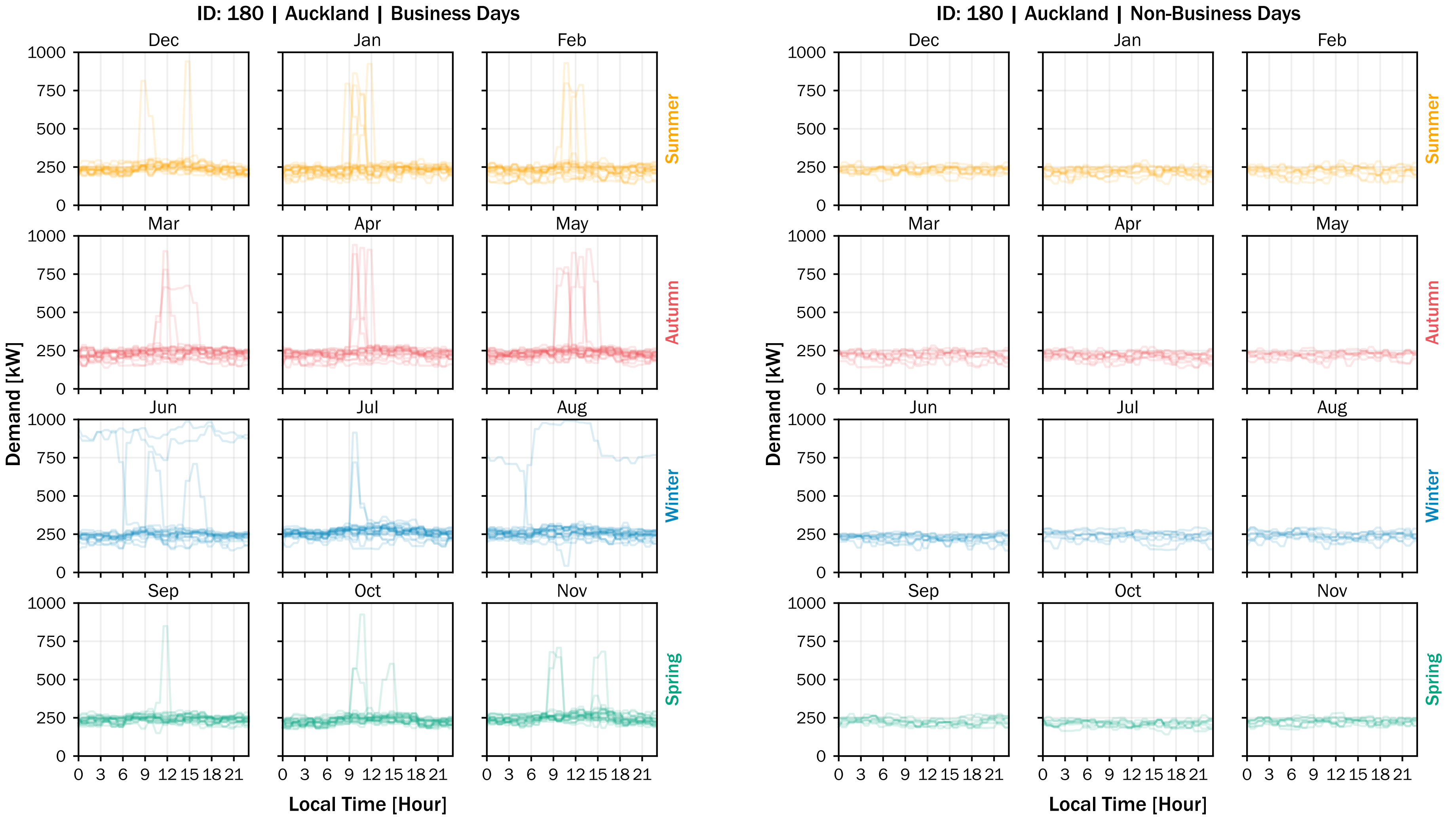
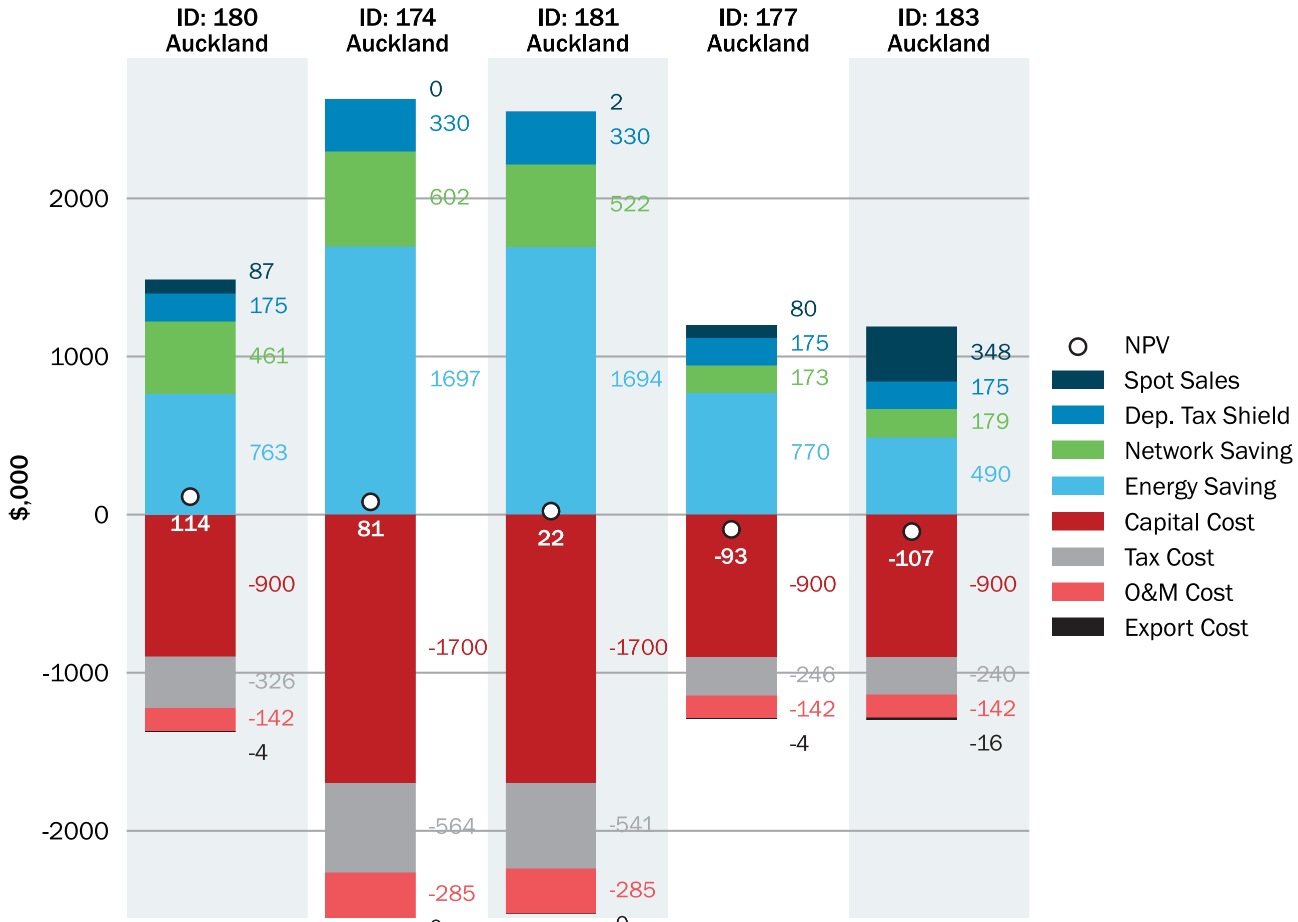


Figure 66: 2019 calendar year load of water supply plant Site 180. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



	ID: 180 Auckland	ID: 174 Auckland	ID: 181 Auckland	ID: 177 Auckland	ID: 183 Auckland
IRR	8.5 %	7.6 %	7.2 %	5.7 %	5.5 %
PV	500 kW	1000 kW	1000 kW	500 kW	500 kW
Capacity Factor	0.15	0.15	0.15	0.15	0.15
Average Load	243 kW	5366 kW	3520 kW	255 kW	183 kW
Max Load	986 kW	12023 kW	5178 kW	526 kW	683 kW
Self Consumption	86.9 %	100.0 %	99.8 %	87.9 %	55.8 %

Figure 67: Financial results of analysis of solar at water supply plant Site 180 and another four sites. Site 181 is also water supply, while the other three sites are waste water treatment.

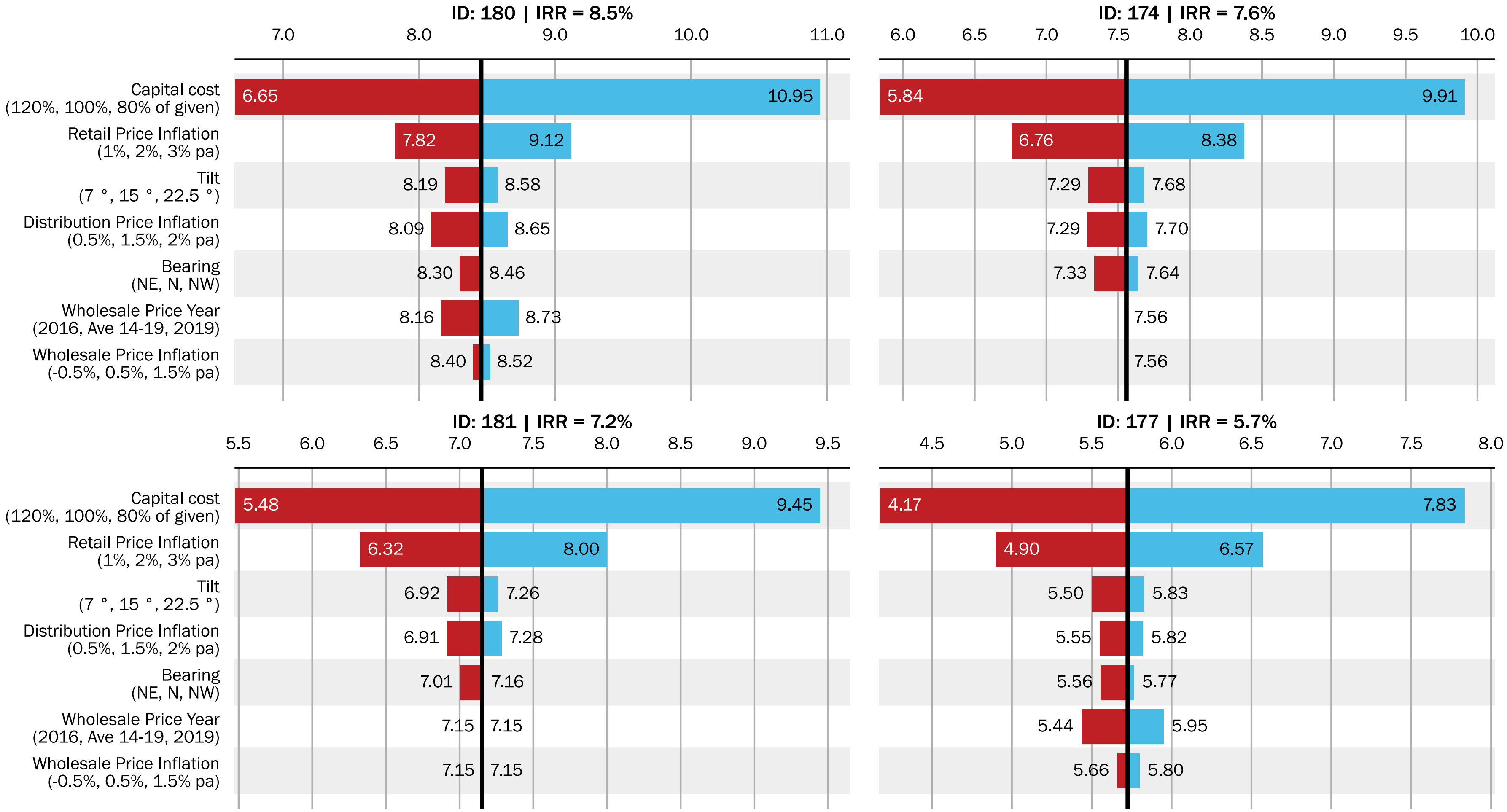


Figure 68: Sensitivity of IRR to inputs for water treatment plant Site 180 and three other sites. As above, Site 181 is also water supply, while the other two sites are waste water treatment.

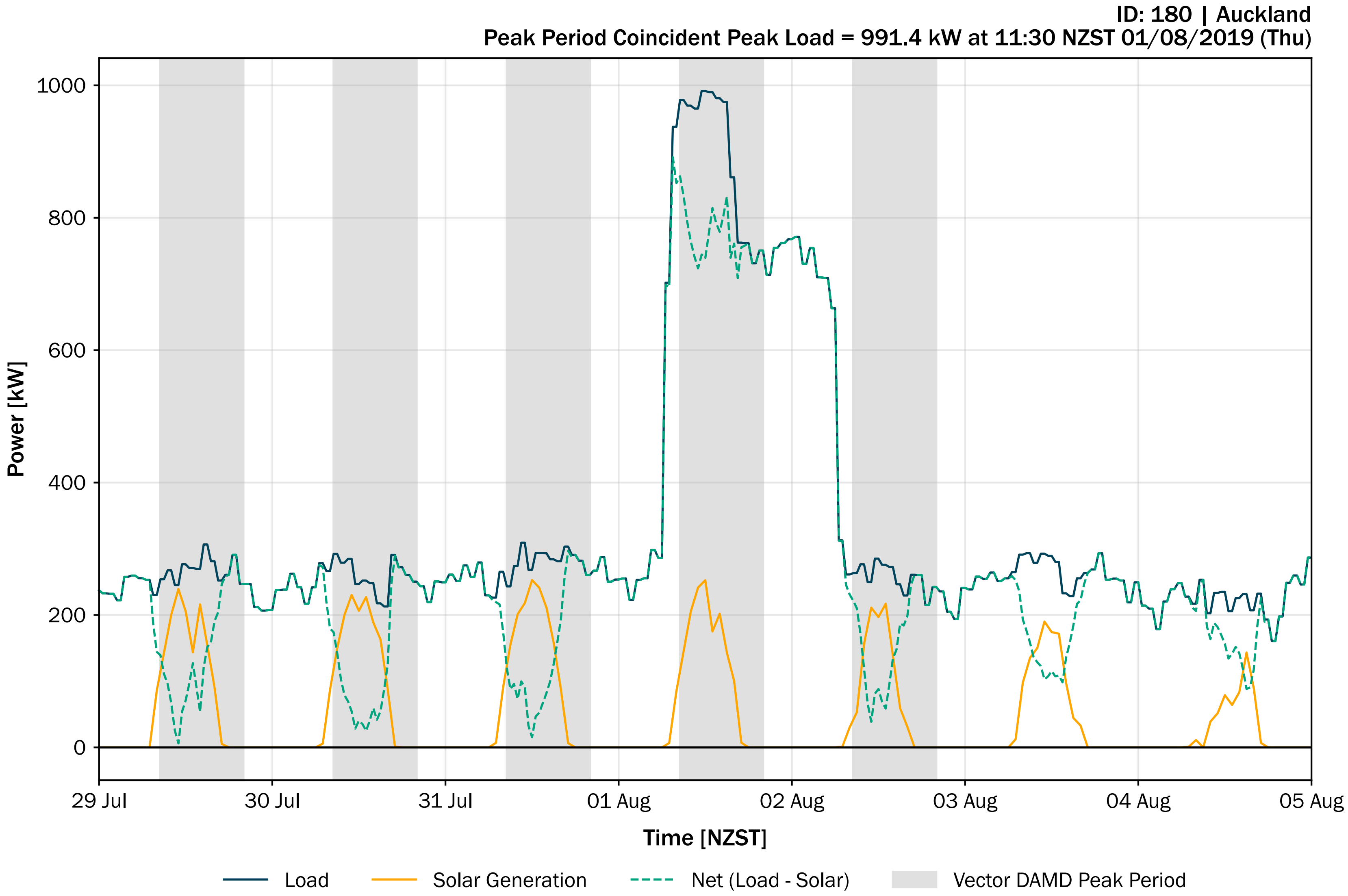


Figure 69: Site 180's load profiles including the time at which the highest kVA load occurred coincident with Vector's peak period.

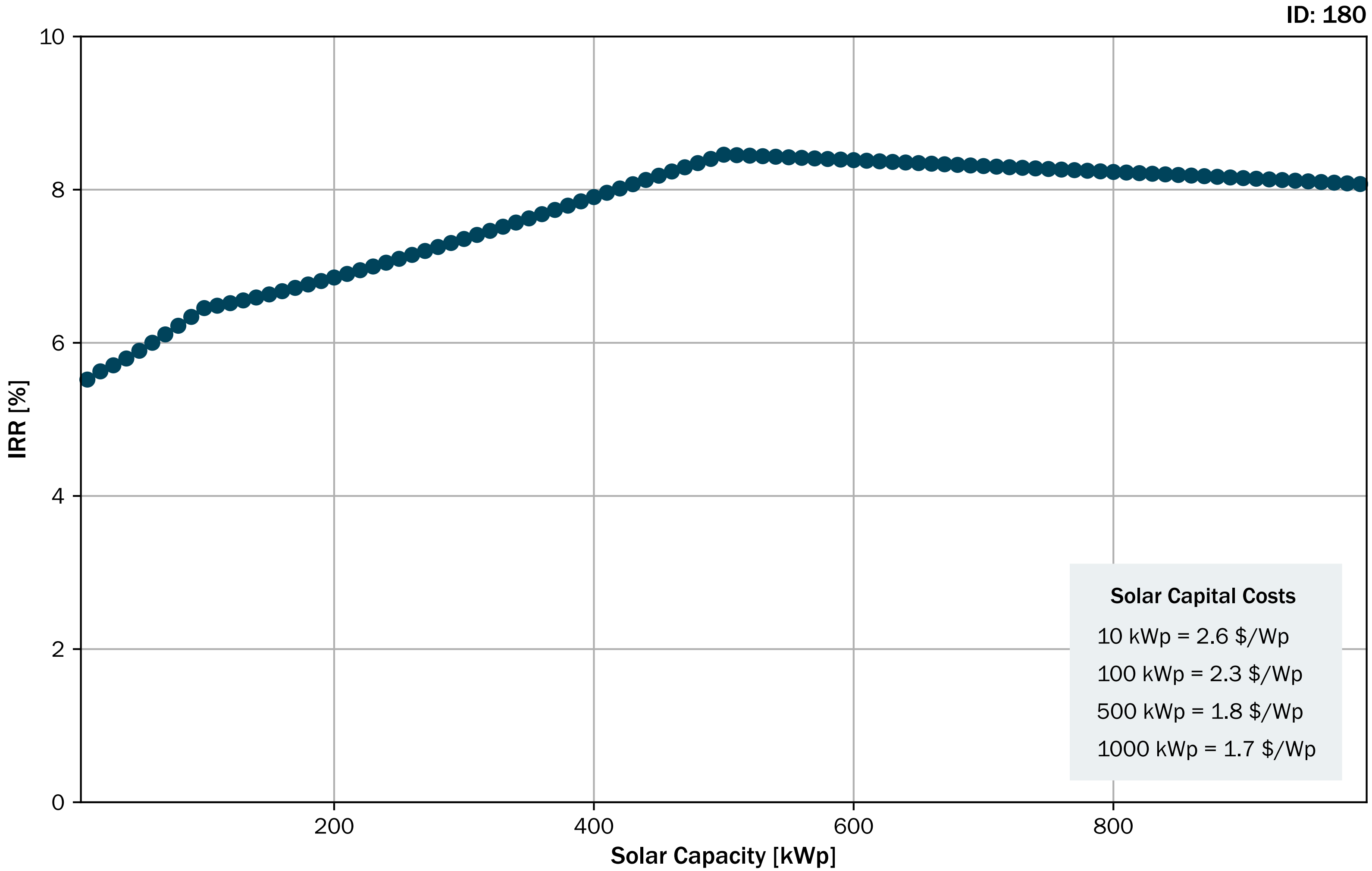


Figure 70: IRR versus solar system capacity for water treatment plant Site 180.

12.12 Dairy farm (DAIRY)

The dairy farm load type is that of a relatively large dairy farm, and does not include any dairy processing.

Figures follow on the next five pages.

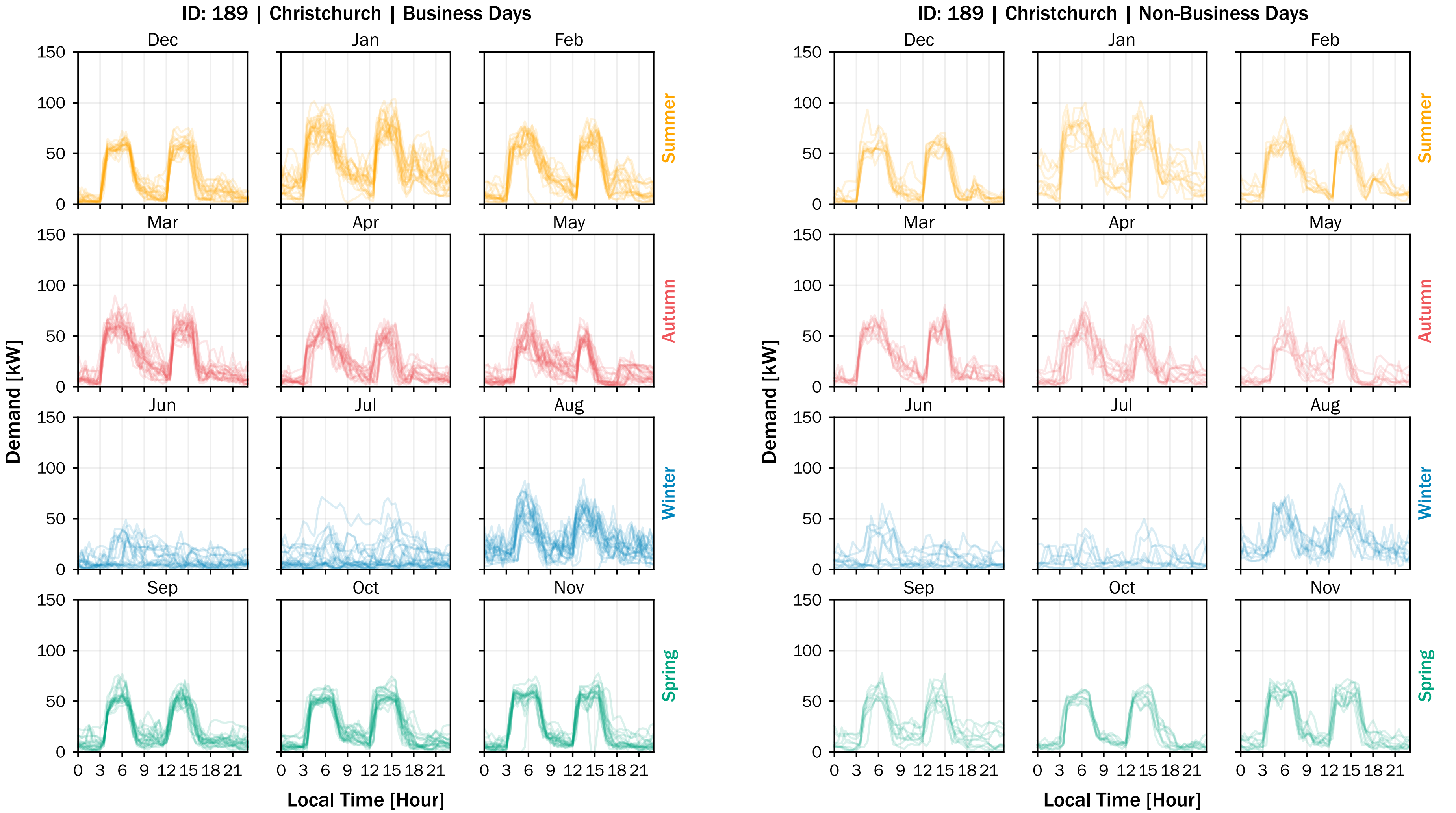
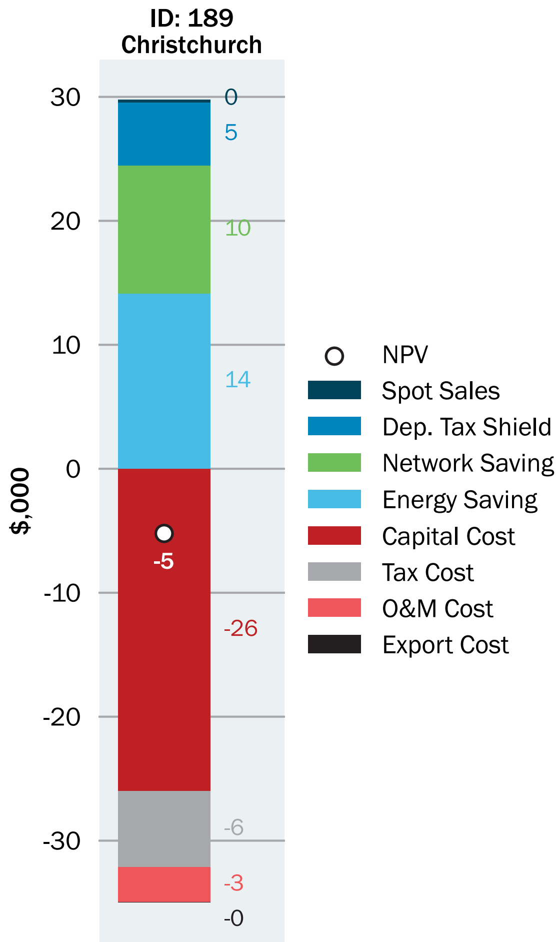


Figure 71: 2019 calendar year load of dairy farm Site 189. Left: business day (defined as 8am to 5pm Monday-Friday excluding public holidays) and right: non-business day.



IRR	4.4 %
PV	10 kW
Capacity Factor	0.14
Average Load	24 kW
Max Load	101 kW
Self Consumption	98.0 %

Figure 72: Financial results of analysis of solar at dairy farm Site 189.

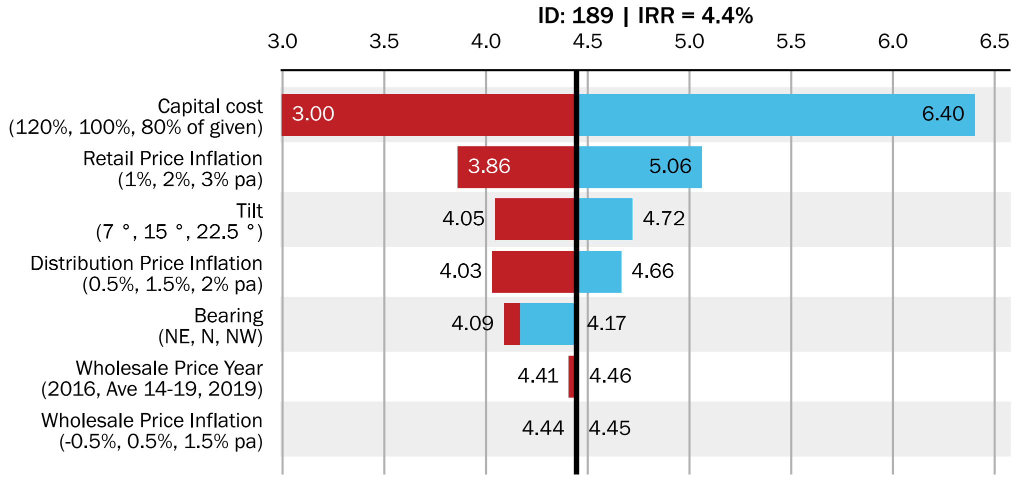


Figure 73: Sensitivity of IRR to inputs for dairy farm Site 189.

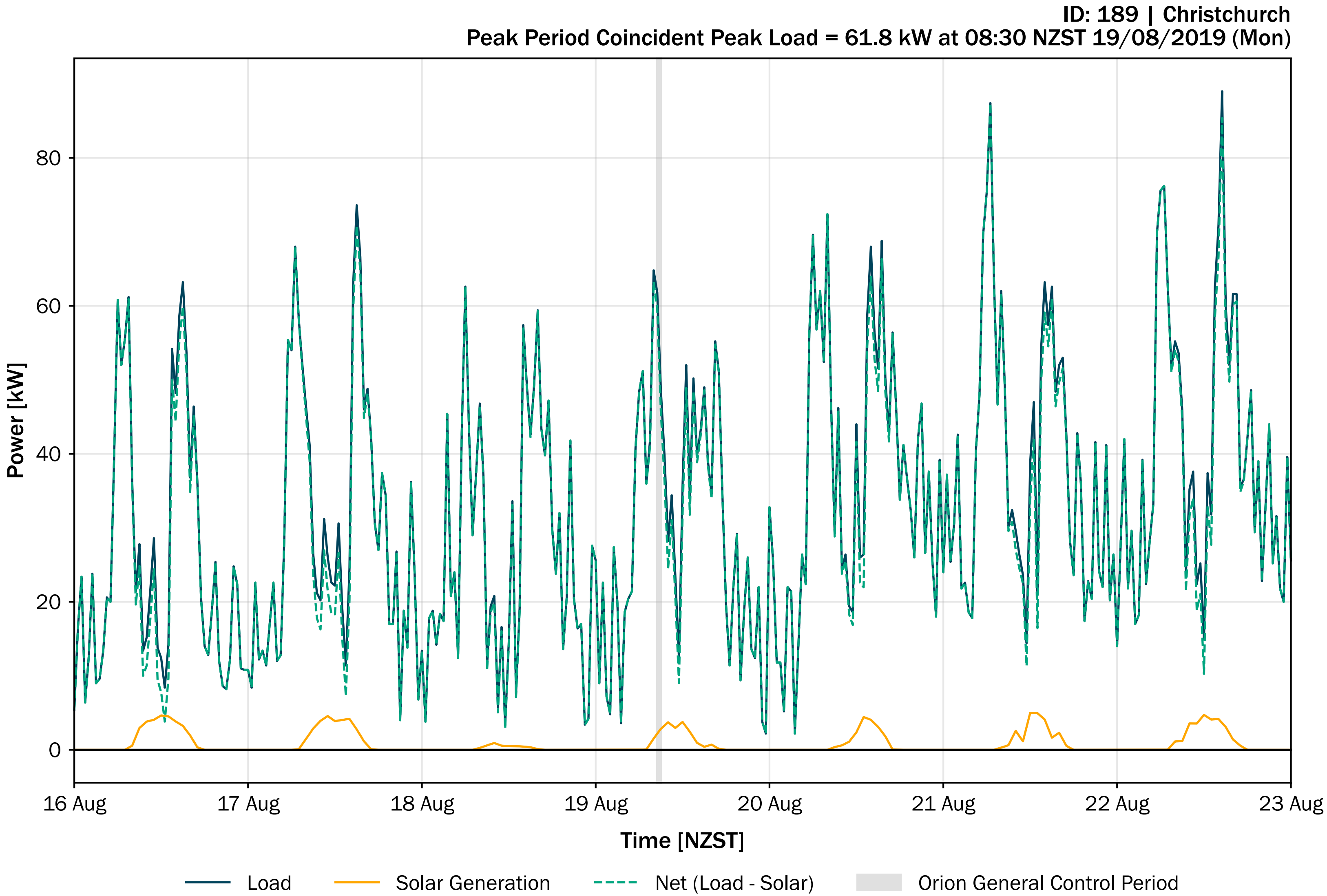


Figure 74: Site 189's load profiles including the time at which the highest kW load occurred coincident with Orion's peak period.

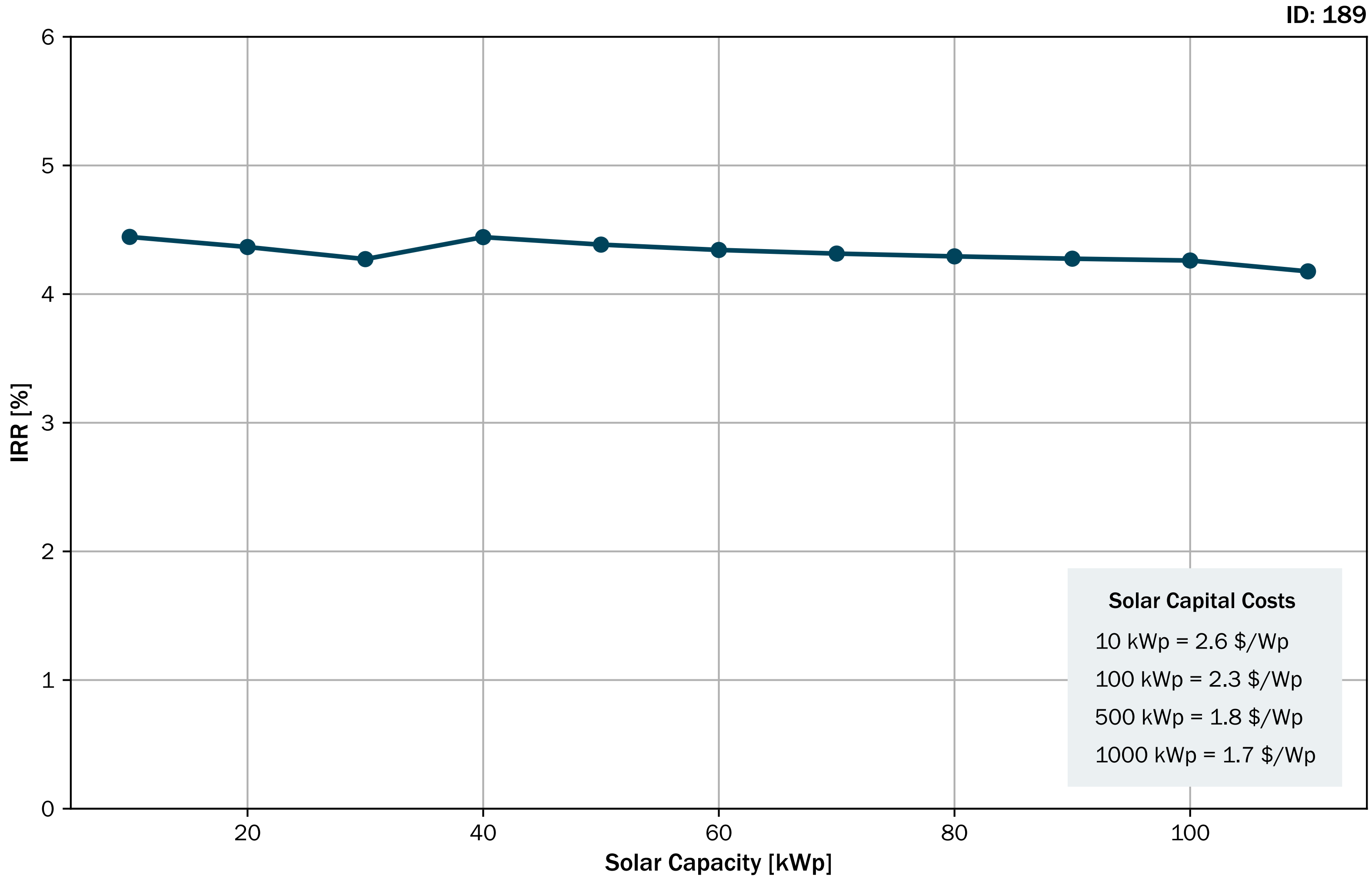


Figure 75: IRR versus solar system capacity for Site 189.