NCC2025 Energy Efficiency - Advice on the technical basis

Initial Measures Development: Electrical Services Report

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Measures investigated in this report include:

- EV charging
- PV/battery analysis
- Lighting control
- Peak demand management

[Draft regulation text shown in this report was originally provided to the ABCB for consideration and further development. It may not reflect final provisions for public comment. The draft regulation below also may not reflect any changes following feedback received from the ABCB or various industry stakeholders.]

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1 Introduction

Section J of the National Construction Code (Volume 1) is undergoing a cyclic review of both stringency and coverage. This report records the analyses for the initial measures development for NCC2025 pertaining to Electrical Services.

1.1 Project Context

Section J of the National Construction Code (Volume 1) last underwent a significant review for the 2019 edition, with the 2022 edition introducing requirements related to on-site renewables and provisions for future electric vehicles chargers. Since then, technologies have advanced in some areas, creating the opportunity for enhanced stringency. Furthermore, external pressures on Code from factors such as net zero targets at State and Australian government level have added to ambition.

2 EV Charging

2.1 Background and context

The consideration of the provision of EV charging is a separate standalone measure from other analyses conducted for NCC2025. The benefits of such facilities are functional rather than building energy efficiency related. As a result, no benefit cost analysis is conducted; however cost information is provided to provide context for the proposed provisions.

2.1.1 Electrical Vehicle (EV) Types

An EV is a shortened acronym for an electric vehicle. EVs are vehicles that are either partially or fully powered on electric power. There are three types of cars that are often referred to as 'electric vehicles':

- HEV – Hybrid Electric Vehicle (no Plug), e.g., Toyota Prius
    - Hybrid between petrol and electric with both internal combustion and electric motors, but no electrical charging plug.
- PHEV – Plug-in Electric Vehicle, e.g., Mitsubishi Outlander PHEV
    - Hybrid between petrol and electric with both internal combustion and electric motors with an electrical charging plug.
- BEV – Battery Electric Vehicle, e.g., Tesla 3, Polestar, Nissan Leaf
    - True electrical vehicle.

In this analysis, EV is used generically to refer to vehicles that can be charged via an electrical plug, i.e., BEVs and PHEVs, as they both contribute to electrical charging demand. However the underlying assumptions in the analysis are focussed on BEVs as these have more significant charging requirements.

2.1.2 EVs: Changing the way we drive

The automotive industry is currently experiencing a significant transformation with the increasing prominence of electric vehicles (EVs). As society seeks to reduce dependence on fossil fuels and mitigate the environmental impact of transportation, EVs have emerged as a promising solution. This fundamental shift in propulsion technology brings numerous advantages and has far-reaching implications for the automotive industry and society as a whole.

One of the key incentives for electric vehicles lies in their contribution to environmental sustainability. Unlike ICE vehicles, which emit greenhouse gases and pollutants during operation, electric vehicles produce zero tailpipe emissions. By reducing or eliminating carbon dioxide (CO_2) emissions, EVs can play an important role in combating climate change and improving air quality, thereby mitigating the detrimental effects on human health and the environment.

While electric vehicles (EVs) offer numerous environmental and operational benefits, availability and cost concerns associated with EV charging stations are one of the factors that need to be considered in terms of infrastructure installation, electrical infrastructure upgrades, and equipment and maintenance costs.

Increasing the number of EV chargers is expected to impact grid power demand. As the EV market continues to grow and more charging stations are installed, it is necessary to consider the potential impacts this will have on the electrical grid, and how the grid can accommodate the added load from EV installations to avoid failure in charging systems. This may to some extent be mitigated by use of vehicle-to-grid (V2G) technology which enables bidirectional energy flow between EVs and the electrical grid[1]. EVs can serve as mobile energy storage units, allowing surplus electricity from the grid to be stored in EV batteries and subsequently fed back into the grid during peak demand periods. V2G integration could, in future, provide grid support and create opportunities for vehicle owners to earn revenue from their EVs. While vehicle to grid is currently facing technological and regulatory challenges, the possibility of application exists in South Australia, with one charger manufacturer.

On other hand, safety provisions for EV charging stations are important factors to provide safe operation of charging infrastructure and protect users, vehicles, and the surrounding environment. Firefighting services and governing bodies are responding to the risk of electrical lithium-ion fires with varying approaches. It is noted that the lack of regulation in this area has led to highly contextual risk handling for individual projects. ABCB has commissioned separate work on this topic which should be considered in parallel with the recommendations in this assessment.

2.1.3 EV Chargers

An EV charger draws electric power from the grid and delivers it to the EV through a connector or plug. The electric vehicle stores that electricity in a large battery pack to power its electric motor(s).

There are different types of EV charging. To recharge an EV, an EV charger’s connector is plugged into the electric car inlet (equivalent to a traditional car’s gas tank) via a charging cable. EV batteries can only accept direct current (DC) power.

There are essentially two pieces of key terminology that assist in choosing suitable EV chargers for specific car models:

- Charging Levels – the power at which the electric vehicle can be charged, grouped into a few key bands (Levels 1 to 3)
- Charging Types – the physical plug connector type that plugs into the electric car.

EV Charger Types and Charging Levels

There are 3 different types of EV chargers. Each type of EV charger provides a different “charging level”. The charging level refers to the rate at which the electric vehicle will charge.

The three different levels of EV charging are:

- Level 1 EV Charger Type - AC Slow Charging. 240 Volt, single phase, 1.4-2.4 kW
- Level 2 EV Charger Type - AC Fast Charging.
    - 240 Volt, single phase, typically 7 kW
    - 415 Volt, three phase, typically 22 kW
- Level 3 EV Charger Type - DC Fast Charging. 480Volt, 25-350 kW

[1] This technology is not yet available on a general basis in Australia.

The higher the EV charging level, the faster it will charge the electric vehicle. Level 2 EV chargers are suitable for charging the vehicle overnight at home. However, level 3 EV chargers are best for quickly charging the vehicle whilst in public or on a long road trip.

Level 1 EV Charger Type – AC slow Charging

Level 1 EV charging is the slowest of the three EV charging levels. Level 1 chargers are typically only used in homes and can be plugged directly into a standard residential power outlet. Level 1 EV charging equipment typically comes standard when you purchase an electric vehicle.

Level 1 EV charging is best suited to electric vehicles with smaller battery sizes, such as plug-in hybrids. It may be sufficient if the electric vehicle is not driven very often (less than 40km per day) or very far (less than 4000km per year). Level 1 EV charging is reliable; however, the electric vehicle must be charged for long periods of time between each drive. A full charge using level 1 EV charging can take anywhere from 8 to 40+ hours, depending on the size of the vehicle's battery.

Level 2 EV Charger Type- AC Fast Charging

Level 2 EV charging provides mid-tier charging rates and is considerably faster than level 1 EV charging. Level 2 chargers are the most common type of EV charger and are often used in homes, apartment blocks, workplaces, shopping centres and some public charging stations.

Level 2 EV charging is sufficient if the vehicle operator plans on staying at the charging location for at least one to two hours (e.g., whilst shopping or working). Charging for one hour will typically will add about 40km of range from a level 2 EV charger. L2 is also ideal for charging the vehicle (8+ hours) whilst at home or a hotel. However, if the user wants to use a level 2 EV charger at home, a 'wall box' charger needs to be installed at home that increases the power being delivered.

Level 3 EV Charger Type- DC Fast Charging

Level 3 EV chargers provide rapid charging rates and can be up to 50x faster than level 2 EV chargers. They are designed so that people can quickly recharge their electric vehicle in a matter of minutes using direct current (DC) technology. Typically, L3 chargers are only found in public areas (car parks, petrol stations, roadside, motorways, etc).

Level 3 EV chargers are intended to be used in much the same way that fuel stations are used by petrol/diesel vehicles. This makes level 3 charging the perfect solution for anyone who drives daily or wants to travel long distances in their electric vehicle.

Most EVs on the market can accept a charge rate of at least 50kW. However, it is worth noting that some EV's (such as plug-in hybrids) may have a lower acceptance rate and therefore cannot take full advantage of level 3 charging.

EV Chargers 7 kW Type 2 CCS

NCC 2022 has a dedicated clause J9D4, (refer to section 2.5) for clarifying the requirements of electric vehicle charging stations within different building classes. The following table includes three (3) Type 2 EV chargers each from a different manufacturer that comply with NCC 2022 requirements and were found to be most commonly used.

Charger Type	Power Rating	Connection to the Vehicle	Mounting mode	No. Charging points	Access Control System	Approximate Cost
Charger 1	7.4 kW	Socket-outlet T2 (CCS) with shutter	Wall mounted	1	Key	$2,600/unit
Charger 2	7 kW	Socket-outlet T2 (CCS)	Wall mounted/Ground mounting Pole	1	Smart RFID cards	$2,500/unit
Charger 3	7 kW	Socket-outlet T2 (CCS)	Wall mounted/Ground mounting Pole	1	Smart RFID cards	$2,000/unit

Based on the table above, it is noted that there are no significant differences between the three chargers, however, Charger 2is more suitable for Residential buildings. It offers an effective after sale technical support, budget cost and load management software to control the charger output.

Type 2 CCS Charging GPOs

Australia predominately uses Type 2 and Type 2 CCS (also known as CCS2). Type 2 is generally the agreed standard among all the parties involved in EV charging in Australia (automotive manufacturers and EV charging providers).

Type 2 is the standard plug used for AC charging. While Type 2 CCS (CCS2) adds two large DC pins to allow for DC fast charging. Type 2 and Type 2 CCS (CCS2) is utilised by all major automotive manufacturers including, (but not limited to) Tesla, BMW, Audi, Mercedes-Benz, Hyundai, Kia, BYD, Mini, Porsche, Jaguar, Volvo, Polestar and Cupra.

CHAdeMO is a Japanese DC standard which has been utilised for several years, however due to the benefits and prevalence of CCS2 amongst other automotive brands, CCS2 vehicles outnumber CHAdeMO by a considerable margin.

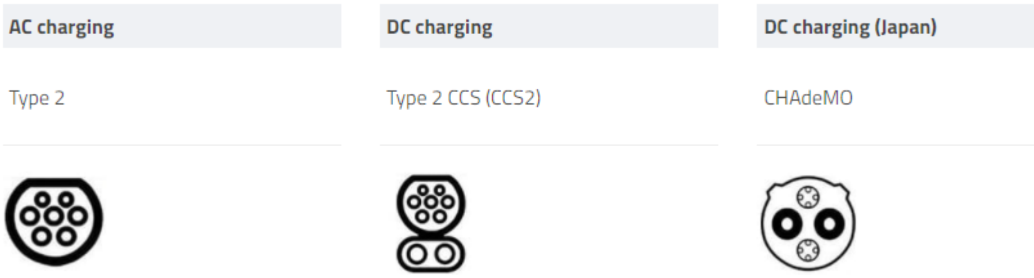

Figure 1: EV Charger Socket Outlet Types

2.1.4 NCC 2022 requirement for Electric Vehicle Charging Equipment

Energy Metering

As per NCC 2022, J9D3, buildings with a floor area of greater than 500 m^2 must have energy meters configured to enable individual time-of-use energy data recording of on-site electric vehicle charging equipment. This energy meter must be interlinked by a communication system that collates the time-of-use energy data to a single interface monitoring system where it can be stored, analysed, and reviewed.

Number of EV chargers/EV car parking spaces

Referring to J9D4, NCC 2022, it is specified that a certain percentage of car parking spaces must be equipped with electric vehicle charging equipment as a future provision. This percentage is based on the class of building (see Table 1 below for details).

Table 1:

Class Building	% Of the car parking spaces that dedicated to EV equipment
Class 2	100% of the car parking spaces
Class 5 or 6	10% of car parking spaces
Class 3, 7b, 8 or 9	20% of car parking spaces

EV chargers Maximum Demand Load

In AS3000:2018, Appendix C, Table C1, related to domestic electrical installation, it is noted that there is a diversity factor should be applied based on the number of living units (i.e., apartments), as per Table 2.

Table 2: AS3000:2018 diversity factors for domestic EV charger installations.

No of Living units	% Of connected load of EV charging equipment
Single domestic electrical installation per phase	Fully connected load
2 to 5 living units per phase	100% of connected load
6 to 20 living units per phase	90% of connected load
21 to more living units per phase	75% connected load

In AS3000:2018, Appendix C, Table C2, related to non-domestic electrical installation, it is noted that there is a diversity factor should be applied based on the number EV charging equipment installations, as per Table 3.

Table 3; AS3000:2018 diversity factors for non-domestic EV charger installations.

Building operation	% of connected load of EV charging equipment
• Residential institutions, **• Hotels, boarding** **• Houses, hospitals,** **• Accommodation houses, motels**	Full connected load of highest rated appliance, plus 75% of full load of remainder
• Factories, shops, **• Stores, offices,** **• Business premises,** **• Schools and churches**	Full connected load of highest rated appliance, plus 75% of full load of remainder

Please find below a summary of the key points to consider regarding the EV charging requirements as stipulated in the NCC 2022:

- Energy monitoring for onsite energy resources (like EV charging equipment) is a useful tool to observe usage trends such as peak hours, common usage period, etc. It is also networked with communication systems so that data can be stored and reviewed by facility managers to monitor unexpected usage/operation of electrical equipment.
- NCC 2022 includes specifications for minimum electrical provisions to support future installation of EV charging based on building class and number of car parking spaces.
- Demand load is a critical issue which should be carefully considered to avoid adding much overhead power to the supply. Though it is likely to reflect on the associated cost, most EV charging equipment can be installed with Load Management Systems (LMS) which can distribute the same power output as regular EV chargers and can evenly distribute power between chargers during periods of lower power availability. Variation in charging rate is dependent on the power demand of the network. This will mean load demand is stabilised, however, charging time will be significantly increased.

2.1.5 Load Management System (LMS)

Section J9D4(2) of the NCC2022 (extract in Figure 2 below) requires each class of building has a minimum power amount for the electric chargers to be delivered to the cars in specific time intervals as a readiness measure. For example, in a Class 2 building, the electrical vehicle chargers should deliver minimum 12 kWh from 11:00 pm to 7:00 am the next day. Also, in a Class 3 building, the electrical vehicle chargers should deliver minimum 48 kWh from 11:00 pm to 7:00 am next day.

J9D4 Facilities for electric vehicle charging equipment

[New for 2022]

(1) Subject to (2), a *carpark* associated with a Class 2, 3, 5, 6, 7b, 8 or 9 building must be provided with electrical distribution boards dedicated to electric vehicle charging—

(a) in accordance with Table J9D4 in each *storey* of the *carpark*; and

(b) labelled to indicate use for electric vehicle charging equipment.

(2) Electrical distribution boards dedicated to serving electric vehicle charging in a *carpark* must—

(a) be fitted with a charging control system with the ability to manage and schedule charging of electric vehicles in response to total building demand; and

(b) when associated with a Class 2 building, have capacity for each circuit to support an electric vehicle charger able to deliver a minimum of 12 kWh from 11:00 pm to 7:00 am daily; and

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(c) when associated with a Class 5 to 9 building, have capacity for each circuit to support an electric vehicle charger able to deliver a minimum of 12 kWh from 9:00 am to 5:00 pm daily; and

(d) when associated with a Class 3 building, have capacity for each circuit to support an electric vehicle charger able to deliver a minimum of 48 kWh from 11:00 pm to 7:00 am daily; and

(e) be sized to support the future installation of a 7 kW (32 A) type 2 electric vehicle charger in—

(i) 100% of the car parking spaces associated with a Class 2 building; or

(ii) 10% of car parking spaces associated with a Class 5 or 6 building; or

(iii) 20% of car parking spaces associated with a Class 3, 7b, 8 or 9 building; and

(f) contain space of at least 36 mm width of DIN rail per outgoing circuit for individual sub-circuit electricity metering to record electricity use of electric vehicle charging equipment; and

Figure 2: NCC 2022 Extract - Electric Vehicle Charging Requirements

Based on the J9D4(2) requirements as presented in Figure 2, the installation of a load management system becomes a priority in any Electric Vehicle Charging system, as through this system, EV chargers can fulfil and comply with NCC2022 requirements without adding much overhead power to the electrical system.

Load management means that users can specify the amount of power used for charging EVs. If the power demanded by the charging system exceeds the power supply from the grid, the system controller, with Load Management-enabled, will re-calculate and modify the available power at each charging point.

There are 3 options supported by Load Management:

- **Static Load Management**
  Static load management evenly distributes a charging power pre-set for all charging stations across several connected electric cars, no matter how many of the individual electric cars are actually charging. Every charging station is allocated the same charging power within the limited power's range.
- **Scheduled Load Management (Scheduling)**
  The available charging power is divided up according to different times in a day. This

allows you to take advantage of time-of-use tariffs (TOUs) and allocated more supply at times when the site supply is more readily available.

- **Active Load Management (ALM)**
  Active load management (ALM) is one of the EO Genius' most advanced features which separates it in the Australian market as it does not need a charging power pre-set. Instead, the charging power's range is dynamically modified by the controller based on the power consumption in the entire building: If the power consumption in the building decreases, then more electricity becomes available for EV charging. In contrast, if the power consumption in the building increases, then there is less electricity available for EVs. Figure 3 shows how the load management system works.

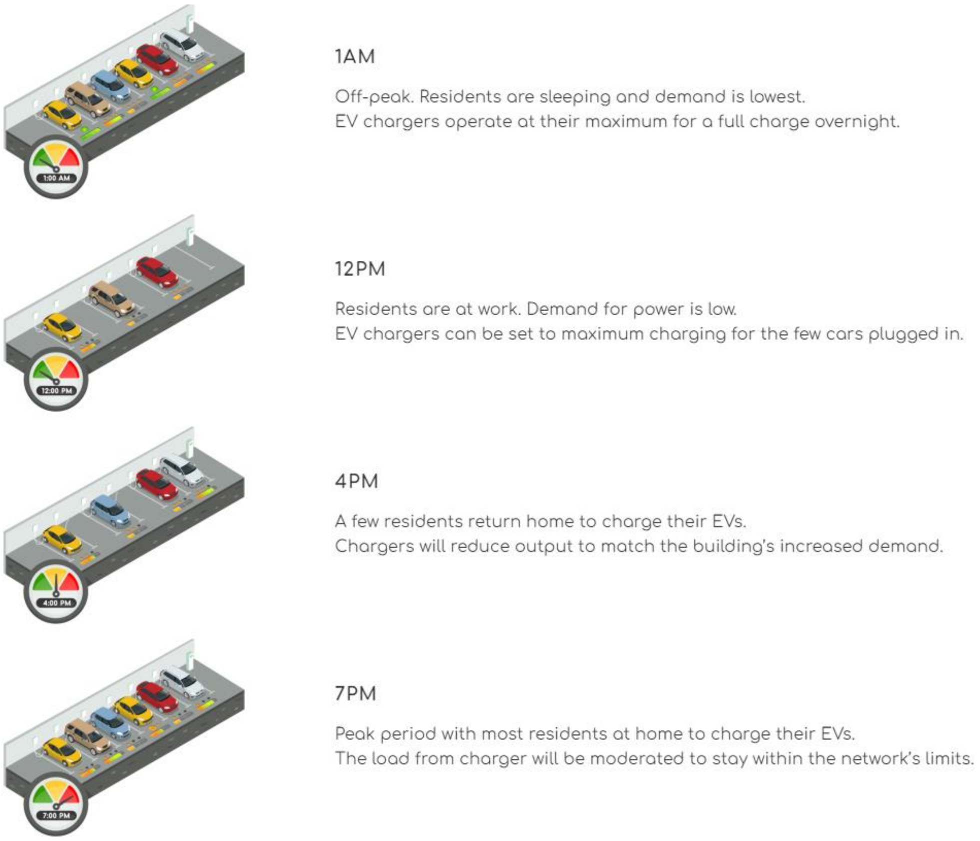

Figure 3: EV Load Management System

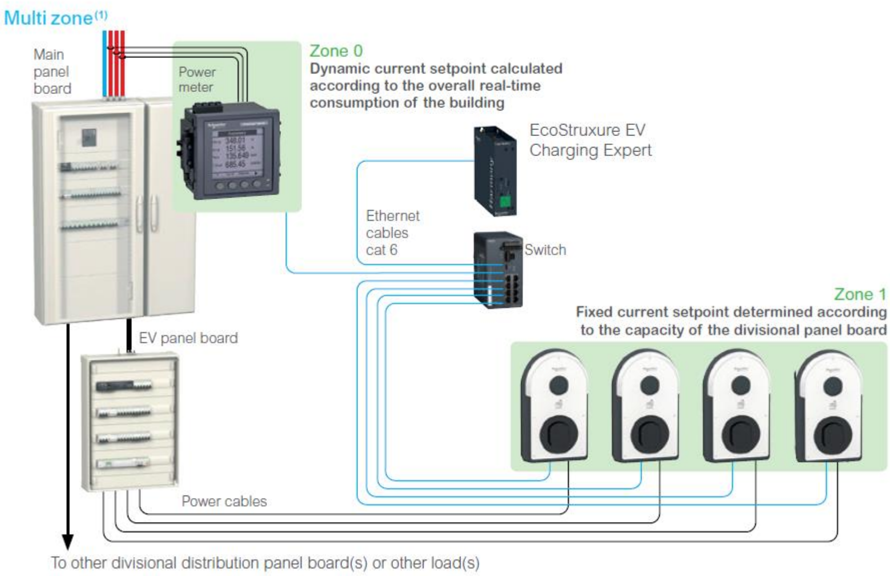

Figure 4: Active Load Management System[2]

Any of the three LMS described above would meet this requirement. AS/NZS 3000 also allows maximum demand to be determined by calculation, which would take into account the presence of the LMS when calculating peak demand. This should limit the impact of EV charging on the total required building electrical supply.

Refer to Appendix C: EV Charging for more cost and price information for different Archetypes.

[2] EV Up 2020, "EV Charging Dynamic Load Management", Accessed 15th June 2023, https://www.evup.com.au/ev-charging-station-load-management

2.2 Methodology

The outline methodology is shown in Figure 5.

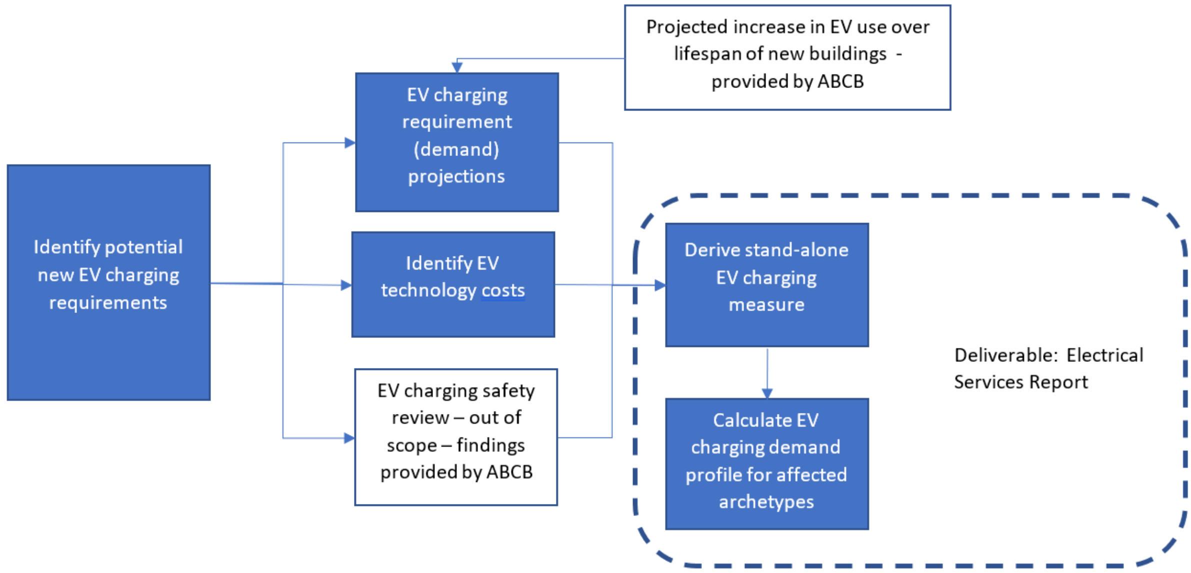

Figure 5: Outline Methodology for the EV Charging Analysis

2.2.1 EV Sales Projection

The CSIRO projections report[3] provides electric vehicle uptake and population projections, focussed on battery electric vehicles, plug-in hybrid electric vehicles and fuel cell electric vehicles (BEVs, PHEVs and FCEVs). Due to differences in costs, the CSIRO projections report considers short and long duration BEVs separately in the modelling methodology. Only electric vehicles in the on-road sector are considered. Electrification of vehicles in off-road sectors such as mining are not included. On-road vehicles include light vehicles (cars and motorcycles) owned by households or businesses as well as trucks and buses.

Our methodology for NCC2025 is to use the CSIRO report for EV data to project the number of EVs that will be on the road by 2030 and by 2035; then apply the required percentage of EV parking spaces of each archetype that has been stipulated in NCC 2022. Based on this methodology, cost estimates for these provisions for a sample set of archetypes has been calculated. The proposed measure extrapolates these results and applies them to the remaining building classes not included under the costing exercises.

2.2.2 Projection Scenarios

Referring to the CSIRO projections report, there are four scenarios that have been considered in the projection methodology. The four scenarios are **Progressive Change, Exploring Alternatives, Step Change** and **Hydrogen Export**. The Australian Energy Market Operator (AEMO)[4] scenario definitions are described in detail in CSIRO report.

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[3] Graham, P. CSIRO, 2022, Electric Vehicle Projections.

[4] Australian Energy Market Operator (AEMO) 2021, NEM Virtual Power Plant Demonstrations: Knowledge Sharing Report #4, AEMO.

2.3 Results

2.3.1 Electric Vehicle Projection

Based on above scenarios, the projections results have been developed in the CSIRO report as per Figure 6, which shows significant increase in EV car sales from now to 2050, and Figure 7, which shows the projected electric vehicle fleet in all Australia until 2055.

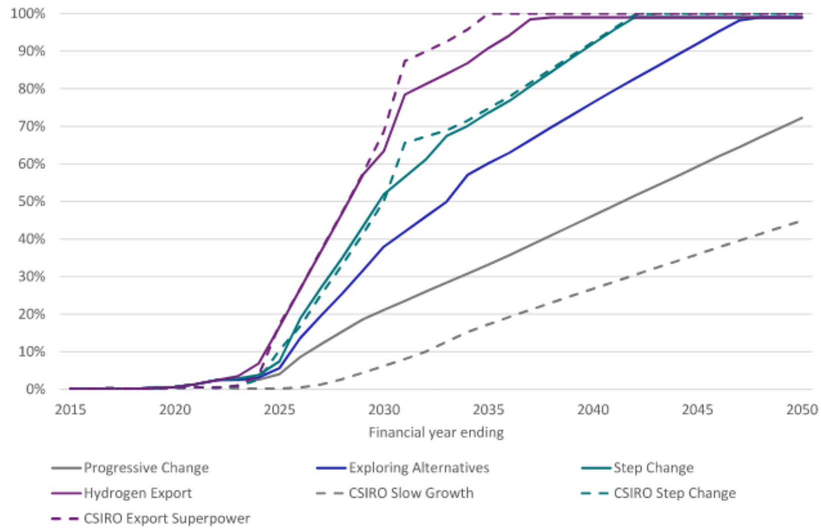


Figure 6: Projected Electric Vehicle Sales[5]

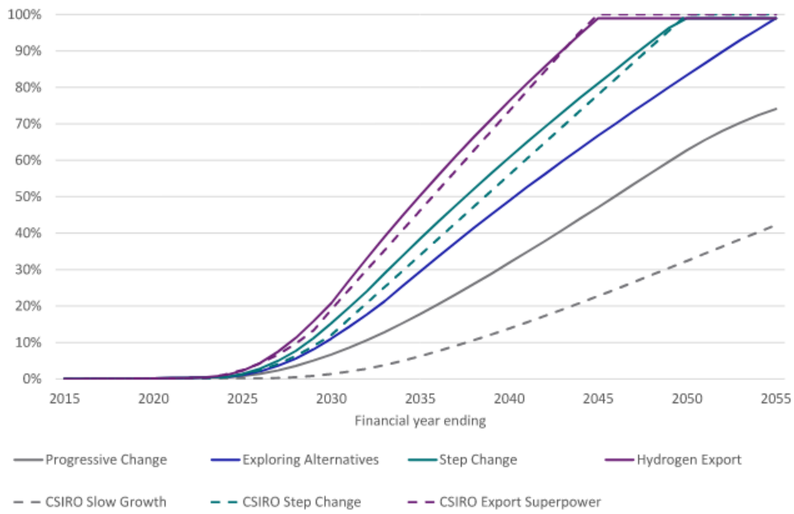


Figure 7: Projected Electric Vehicle Fleet Share[6]

Extracting the fleet share figures for each scenario in Figure 7 for 2030 and 2035, provides the summary under Table 4. These years were selected specifically to target the period in a building's lifecycle that will meet a balance between coverage of NCC2025 implementation (the period when buildings are constructed and operated as a result of NCC2025 in legislation) while not imposing the installation of equipment/technology that becomes redundant for the majority of a building's lifecycle.

[5] Graham, P. CSIRO, 2022, Electric Vehicle Projections.
[6] Graham, P. CSIRO, 2022, Electric Vehicle Projections.

Table 4: Calculated EV Projection as a Proportion of all Registered Light Vehicles in Australia for 2030 and 2035

Scenarios	% of EVs by 2030	% of EVs by 2035
Progressive Change	6.7%	17.8%
Exploring Alternatives	11.1%	29.5%
Step Change	15.3%	38.5%
Hydrogen Export	20.8%	50.4%
Average	**13.5%**	**34%**

Given that the projection scenarios are presented to provide an insight into a wide range of economic futures with no reference to potential or likelihood of one over the other, it's not possible to base an analysis on one. Rather, the average EV fleet share projection of the four scenarios has been assumed and used as an input into further cost analysis later in this section.

2.3.2 Level 2 EV Charger and Installation Costs

Based on the above projection scenarios and percentages, the estimated costs for supply and installation of EV charger(s) (additional to the NCC 2022 provision) each archetype will be as per Table 5 to Table 8 below to the limit stipulated by NCC 2022. Infrastructure costs include supply and installation of equipment such as electrical cables and cable trays, whereas ancillary costs include data/communications cabling.

Detailed calculation tables are also provided in Appendix C: EV Charging.

Table 5: EV Charger Supply and Installation Costs for the Class 2 Archetype, for 2030 and 2035 Projections. Archetype details: Class 2 - 10 Storey building, 55 Apartments, 2 Car Spaces for each apartment, Provision for 110 EV chargers as per NCC 2022.

	Projection Scenario for 2030				Projection Scenario for 2035			
	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
EV Proportion of Total Fleet	6.7%	11.1%	15.3%	20.8%	17.8%	29.5%	38.5%	50.4%
Number of EV Chargers	8 chargers (6.7% of 110)	13 chargers (11.1% of 110)	17 chargers (15.3% of 110)	23 Chargers (20.8% of 110)	20 chargers (17.8% of 110)	33 chargers (29.5% of 110)	42 chargers (38.5% of 110)	55 Chargers (50.4% of 110)
Cost of Chargers	$21,600	$35,100	$45,900	$62,100	$54,000	$89,100	$113,400	$148,500
Cost of Electrical Infrastructure	$28,700	$63,700	$101,200	$173,100	$134,800	$335,000	$525,500	$875,900
Cost of Ancillary Equipment	$4,000	$6,500	$8,500	$11,500	$10,000	$16,500	$21,000	$27,500
Total Cost	**$54,300**	**$105,300**	**$155,600**	**$246,700**	**$198,800**	**$440,600**	**$659,900**	**$1,051,900**

Table 6: EV Charger Supply and Installation Costs for the Class 3 Archetype, for 2030 and 2035 Projections. Archetype Details: Class 3 - 2 storey Hotel/Motel Building, 1,000 m2, 35 Total car spaces, Provision for 7 EV chargers as per NCC 2022.

	Projection Scenario for 2030				Projection Scenario for 2035			
	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
EV Proportion of Total Fleet	6.7%	11.1%	15.3%	20.8%	17.8%	29.5%	38.5%	50.4%
Number of EV Chargers	3 chargers (6.7% of 35)	4 chargers (11.1% of 35)	6 chargers (15.3% of 35)	7 Chargers (20% of 35)	7 Chargers (20% of 35)	7 Chargers (20% of 35)	7 Chargers (20% of 35)	7 Chargers (20% of 35)
Cost of Chargers	$8,100	$10,800	$16,200	$18,900	$18,900	$18,900	$18,900	$18,900
Cost of Electrical Infrastructure	$6,800	$10,200	$18,400	$23,300	$23,300	$23,300	$23,300	$23,300

	Projection Scenario for 2030				Projection Scenario for 2035			
	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Cost of Ancillary Equipment	$1,500	$2,000	$3,000	$3,500	$3,500	$3,500	$3,500	$3,500
Total Cost	**$16,400**	**$23,000**	**$37,600**	**$45,700**	**$45,700**	**$45,700**	**$45,700**	**$45,700**

Table 7: EV Charger Supply and Installation Costs for the Class 5 Archetype, for 2030 and 2035 Projections. Archetype Details: Class 5 - 10 storey commercial office building, 10,000m2, 50 total Car Parking Spaces. Provision for 5 EV chargers as per NCC 2022.

	Projection Scenario for 2030				Projection Scenario for 2035			
	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
EV Proportion of Total Fleet	6.7%	11.1%	15.3%	20.8%	17.8%	29.5%	38.5%	50.4%
Number of EV Chargers	4 chargers (6.7% of 50)	5 chargers (10% of 50)	5 chargers (10% of 50)	5 chargers (10% of 50)	5 chargers (10% of 50)	5 chargers (10% of 50)	5 chargers (10% of 50)	5 chargers (10% of 50)
Cost of Chargers	$10,800	$13,500	$13,500	$13,500	$13,500	$13,500	$13,500	$13,500
Cost of Electrical Infrastructure	$10,200	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000
Cost of Ancillary Equipment	$2,000	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Cost	**$23,000**	**$30,000**	**$30,000**	**$30,000**	**$30,000**	**$30,000**	**$30,000**	**$30,000**

Table 8: EV Charger Supply and Installation Costs for the Class 9c Archetype, for 2030 and 2035 Projections. Archetype Details: Class 9c - 2 storey building aged care facility, 2000m2. 150 total Car Parking Spaces Provision for 30 EV chargers as per NCC 2022.

	Projection Scenario for 2030				Projection Scenario for 2035			
	Progressive Change	**Exploring Alternatives**	**Step Change**	**Hydrogen Export**	**Progressive Change**	**Exploring Alternatives**	**Step Change**	**Hydrogen Export**
EV Proportion of Total Fleet	6.7%	11.1%	15.3%	20.8%	17.8%	29.5%	38.5%	50.4%
Number of EV Chargers	10 chargers (6.7% of 150)	17 chargers (11.1% of 150)	23 chargers (15.3% of 150)	30 chargers (20% of 150)	27 chargers (17.8% of 150)	30 chargers (20% of 150)	30 chargers (20% of 150)	30 chargers (20% of 150)
Cost of Chargers	$27,000	$45,900	$62,100	$81,000	$72,900	$81,000	$81,000	$81,000
Cost of Electrical Infrastructure	$41,100	$101,100	$173,100	$280,900	$231,500	$280,900	$280,900	$280,900
Cost of Ancillary Equipment	$5,000	$8,500	$11,500	$15,000	$13,500	$15,000	$15,000	$15,000
Total Cost	**$73,100**	**$155,500**	**$246,700**	**$376,900**	**$317,900**	**$376,900**	**$376,900**	**$376,900**

2.4 Proposed Measures

The projected growth of EV uptake within Australia should be reflected in the provisional requirements for EV charging under NCC 2025. Given the average projected total fleet share in 2035 across the four scenarios is 34%, the number of car spaces per development with charging infrastructure should follow a similar trajectory (up to the maximum NCC 2022 provision). The estimated costs for the archetypes assessed under this scenario are as follows:

Table 9: Cost Estimates of Proposed Measure for Sample Buildings

Building Class	Assumed Building Metrics	% / No. of Parking Spaces Fitted with EV Chargers	Cost to Install Chargers (additional to NCC2022 provisions)
2	10 Storey building, 55 Apartments 2 Car Spaces for each apartment Provision for 110 EV chargers per NCC 2022	34% / 38	$559,100
3	1,000 m2, 35 Total car spaces Provision for 7 EV chargers per NCC 2022	20% / 7	$45,700
5	10 storey building, 10,000m2, 50 total Car Parking Spaces Provision for 5 EV chargers per NCC 2022	10% / 5	$30,000
9c	2 storey building, 2000m2. 150 total Car Parking Spaces Provision for 30 EV chargers per NCC 2022	20% / 30	$376,900

An analysis has been carried out to investigate the impact on electrical demand for the proposed measure (on the sample buildings). The peak periods for EV charging can vary depending on factors such as geographic location, charging infrastructure availability, user behaviour, and electricity pricing structures. While there is universally fixed time for EV charging peak, some general considerations are as follows:

- Residential peak (for example, building Class 2): In residential areas, the peak period for EV charging often aligns with other household electricity consumption patterns. This typically occurs in the evening hours when people are returning home from work. These periods are where the overall building electrical demand is at maximum. Peak EV load is therefore correlated with household electricity patterns.
- Workplace peak (for example, Building Class 5): In areas with significant workplace charging infrastructure, the charging demand peaks during typical working hours, typically from morning until early afternoon. This is when employees who have access to workplace charging stations may plug in their EVs while they are at work. The peak charging period in such locations is influenced by the start and end times of the workday.
- Public charging peak: Public charging stations, particularly those located in busy commercial areas, can experience peak demand during the day, especially during lunch breaks or shopping hours. These periods are when EV owners utilize public charging infrastructure while they are out and about, running errands or engaging in leisure activities.

Based on the methodology and projection scenarios, and EV charging projection, we can expect the charging demand profile for class 2 and class 3 buildings are similar in terms of peak value and peak period. Also, class 5 and class 9 buildings have the same charging demand profile. Detailed results are presented in Appendix C: EV Charging.

For simplicity, the current NCC2022 J9D4 provisions have been combined with, and are intended to be replaced by, the proposed measure.

2.4.1 Proposed Code Text

J9DX Facilities for Electric Vehicle Charging

(1) Subject to (2) and (3), a carpark associated with a Class 2, 3, 5, 6, 7b, 8 or 9 building must be fitted with –

a) Electrical distribution boards dedicated to electric vehicle charging –

i. In accordance with Table J9DX in each storey of the carpark; and

ii. Labelled to indicate use for electric vehicle charging equipment.

b) 7 kW (32A) type 2 electric vehicle charger(s) in –

i. 34% of the car parking spaces associated with Class 2 buildings; or

ii. 10% of car parking spaces associated with Class 5 or 6 buildings; or

iii. 20% of car parking spaces associated with Class 3, 7b, 8 or 9 buildings.

(2) Electrical distribution boards dedicated to serving electric vehicle charging in a carpark must –

a) Be fitted with a charging control system with the ability to manage and schedule charging of electric vehicles in response to total building demand; and

b) when associated with a Class 2 building, have capacity for each circuit to support an electric vehicle charger able to deliver a minimum of 12 kWh from 11:00 pm to 7:00 am daily; and

c) when associated with a Class 5 to 9 building, have capacity for each circuit to support an electric vehicle charger able to deliver a minimum of 12 kWh from 9:00 am to 5:00 pm daily; and

d) when associated with a Class 3 building, have capacity for each circuit to support an electric vehicle charger able to deliver a minimum of 48 kWh from 11:00 pm to 7:00 am daily; and

e) when associated with a Class 2 building, be sized to support the future installation of a 7 kW (32 A) type 2 electric vehicle charger in the remaining car parking spaces not fitted with a charger under (1) (b) (i) and –

i. contain space of at least 36 mm width of DIN rail per outgoing circuit for individual sub-circuit electricity metering to record electricity use of electric vehicle charging equipment; and

ii. be labelled to indicate the use of the space required by (f) is for the future installation of metering equipment.

(3) Electric vehicle chargers must be located as close at practical to the electrical distribution boards dedicated to serving electric vehicle charging under J9D4.

Limitations

J9DX does not apply to a stand-alone Class 7A building.

Table J9DX: Electric vehicle distribution board requirement for each storey of a carpark

Carpark spaces per storey for electric vehicles	Electrical distribution boards for electric vehicle charging per storey
0 – 9	0
10 - 24	1
25 - 48	2
49 - 72	3
73 - 96	4
97 - 120	5
121 - 144	6
145 - 168	7

Table Notes

Where there are more than 168 carpark spaces per storey, one additional distribution board must be provided for each additional 24 spaces or part thereof.

2.5 Limitations and Recommendations for Future Work

The CSIRO projections report[7] numbers rely on the total number of electric vehicles on-road sector including the light vehicles category, which covers cars and motorcycles owned by household or business, as well as trucks and buses. Further investigation needs to be done for future studies to obtain projection numbers for Passenger cars. The cost studies could be recalculated based on the new info to acquire a new projection scheme for passenger cars only. For example, a Department of Climate Change, Energy, the Environment and Water (DCCEEW) report[8] suggests the fleet share for EVs in the light vehicle stock could be approximately 15% by 2035, and up to 20% with the introduction of fuel efficiency standards.

Based on above methodology, projection scenarios, cost calculation and charging demand profiles for different archetypes, the following items should be considered in NCC 2025;

1. **Inclusion of EV charging infrastructure requirements**: The projected growth of the EV uptake within Australia should be reflected in the provisional requirements for EV charging under NCC 2025. The number of car spaces per development that require provisional infrastructure for charging should follow the progressive 2% per year fleet growth (300,000 cars per year). Therefore, by 2028 the provisional infrastructure will increase by approximately 10-12% when compared to 2022 requirements to allow buildings to be equipped for the average 2035 projection of 34% total EV passenger cars. As the percentage of car spaces required to have provisional infrastructure exceeds the 34%, mandating a minimum number of operational chargers is proposed i.e., Class 3 increases to 32% provisional infrastructure, with all of those spaces equipped with an installed charger.
2. **Accessibility considerations**: The NCC could address accessibility requirements for EV charging infrastructure to ensure that charging stations are accessible to people with disabilities. This could involve guidelines on the height, location, and operability of charging stations to comply with accessibility standards.

These proposed measures aim to create a robust and efficient EV charging ecosystem that supports the growing number of EVs on the road. Collaboration between governments, utilities, charging infrastructure providers, and vehicle manufacturers is essential for successful implementation and advancement of EV charging infrastructure in the future.

2.6 Additional Analysis – Fast Charging Costs

Although the NCC2022 provisions relate to readiness for single phase Level 2 chargers, and the proposed measure relates to extrapolating from these provisions for the installation of these chargers, a cost analysis for a notional Class 6 scenario has been carried out. For this scenario, higher rated chargers need

[7] Graham, P. CSIRO, 2022, Electric Vehicle Projections.

[8] Department of Climate Change, Energy, the Environment and Water (DCCEEW), 2022, Australia's Emissions Projections 2022.

to be considered to coordinate with the shorter residency time of vehicles in this environment. Faster AC and DC charging can be provided via the following chargers:

- Level 2 EV charger type AC fast charger - 22kW 3-phase AC charger **Ocular IQ Commercial | 22kW | 32A | $2,480**
- Level 3 EV charger type DC fast charger - 60kW DC charger **Ocular Titan | 60kW |125A | $34,000**

Provision for installation cost estimates are as follows (noting that estimated cost for the new Main Switch Board for the proposed archetypes are assumed to be approximately $70,000 to $100,000):

- Around 10% of the MSB cost ($7,000 to $10,000) will be dedicated for the EV distribution board circuit breaker provisions. Additional downstream costs to consider are as follows:
    - EV distribution board cost as per NCC2022 (dedicated boards), will be around $5,000 per distribution board.
    - As the Submain cables size to the associated distribution board will be increase, the associated cost will increase by around by 20-30% in comparison to the current 7kW provisions.

3 PV/Battery analysis

3.1 Background and context

With the maturity of the PV (Photovoltaic) market and sector it is generally understood that rooftop PV is significantly cost-effective (BCR>1) in most situations, which implies that it has potential as a DTS provision. Battery storage is being considered by some buildings currently in the market but has not been assessed for code implementation, based on our understanding at the time of writing.

In both cases, there is a challenge in that PV and batteries are supplementary to building operation. Therefore, the question of cost effectiveness needs to be extended to whether investment in these technologies is comparably more effective at building level than (say) at grid level. It would be a poor outcome to enforce either technology if a lower cost to the economy is achieved by applying the technologies outside the built environment. This result stands true even if market imperfections mean that there are building-level financial incentives for either technology.

3.2 Methodology

The outline methodology is shown in Figure 8.

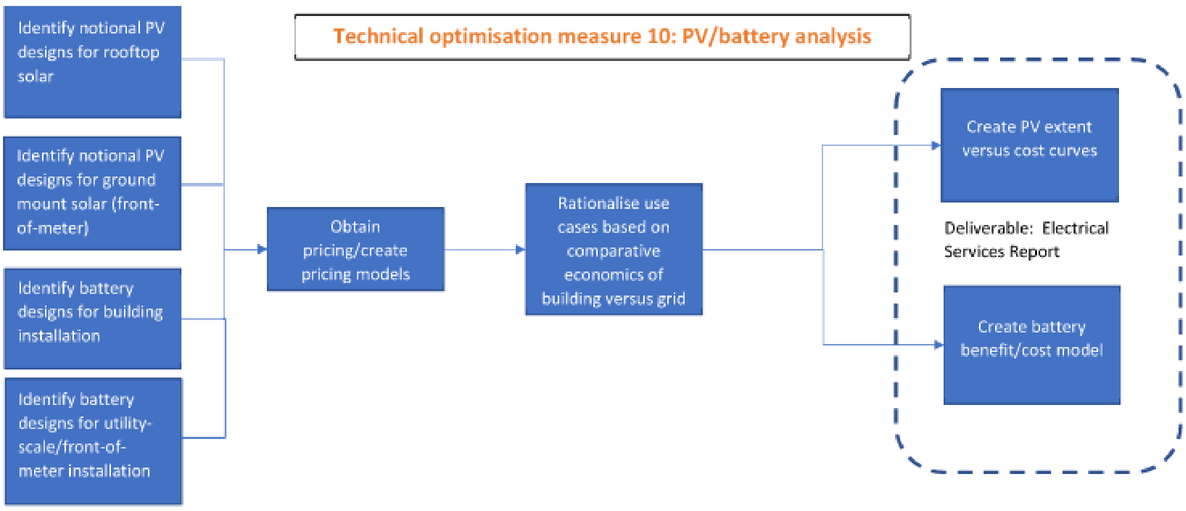


Figure 8. Outline methodology for the PV/Battery analysis

While the original methodology assesses the costs associated with various PV system sizes and locations (behind or front of meter) the resulting code text will need to stipulate a minimum system size. For these reasons, the methodology was extended to include a BCR analysis to determine what is the maximum export proportion of annual generation that results in a BCR of 1. This analysis was further extended to simulations to determine a simplified model of system capacity, which associates PV system size to climate zone and building class. Without such an analysis determination of required minimum capacity would be onerous and prone to flexibility by the designer.

3.3 PV

3.3.1 Scenarios Summary

Given the economics of PV systems are dependent (among other factors) on installation location, a notional location was used for all scenarios. This was selected at random as Goulburn, NSW 2580. Each of the design scenarios under the following sub sections have been selected and are based upon designs that are intended to be representative of the application. Variations on installations have been provided where relevant (primarily for rooftop PV as impacts such as shading are much more controllable for grid PV systems) and insight to impacts such as shading, angle, and soiling has been provided.

3.3.1.1 Behind the Meter

The proposed PV a commercial rooftop systems are 40kWp and 100kWp systems. The equipment selected is based upon Tier 1 Panels and Inverters in the market, specifically Monocrystalline 405-Watt panels with a maximum panel efficiency of 21.1%.

To determine what PV system capacities result in specific levels of export, a system of nominal generation capacity (100 kWp) was modelled and simulated for each of the 8 climate zones. Hourly generation profiles were used and applied (with adjustments to achieve the required level of export) to the hourly consumption results for the four core archetypes (C5OL, C5OM, C9A and C9As).

Installation of the panels will be in North Facing as this is the optimum installation Azimuth Angle for the site location.

Tilt

- **Tilt Angled Panel** is installed as per a notional frame angle which is average 30 degrees.
- **Flat Solar Panel** is 0 degrees, no tilt been used.

Shading

- **No Shading**: the PV system is fully operating 100% based on available solar irradiance, no localised shading exists.
- **Part Shading**: the PV system is operating between 75% to 80% as a result of local shading.
- **Heavy Shading**: the PV system is operating around 50% as a result of local shading.

Capacity

- **40 kW system**: will be achieved through 100 Solar Panels, 40kW Inverter.
- **100kW system:** will be achieved through 250 Solar Panels, 100kW Inverter.

Table 10: PV System - Design and Estimated Yield

PV system	No Shading - No. Panels	No Shading - Annual Generation	No Shading - Estimated System Losses	Part Shading - No. Panels	Part Shading - Annual Generation	Part Shading - Estimated System Losses	Heavy Shading - No. Panels	Heavy Shading - Annual Generation	Heavy Shading - Estimated System Losses
40 kW – Flat Solar Panel	100	56 kWh	11%	100	41 kWh	34%	100	27 kWh	56%
40 kW – Angled Solar Panel	100	63 kWh	11%	100	47 kWh	34%	100	31 kWh	56%
100 kW – Flat Solar Panel	250	140 kWh	11%	250	104 kWh	34%	250	69 kWh	56%
100 kW – Angled Solar Panel	250	159 kWh	11%	250	119 kWh	34%	250	78 kWh	56%

Additional Site Considerations

DNSP (Distributed Network Services Provider) application and connection fees are typical of behind the meter PV installations. However, for existing sites, less typical site specific preliminaries can include the following:

- Height safety system modifications,
- Roofing repairs and modifications to suit PV mounting systems.

Further information regarding design considerations (for example solar panel type and selection, microinverters, etc) detailed information has been provided in Appendix A: PV/Battery Analysis.

3.3.1.2 Grid Level

The details of indicative front of meter ground mounted PV layouts are included in Appendix A: PV/Battery Analysis and the designs are summarised as follows:

ARRAY SIZE	MODULES	INVERTERS	MOUNTING
502 kW	760 x 660W	4 x 110 kVA	30° Fixed Tilt
1,056 kW	1,600 x 660W	8 x 110 kVA	30° Fixed Tilt
3,088 kW	4,680 x 660W	1 x 2,800 kVA	Single-Axis
4,990 kW	7,560 x 660W	1 x 4,400 kVA	Single-Axis
9,979 kW	15,120 x 660W	2 x 4,400 kVA	Single-Axis

Design Methodology

The solar designs have been designed to maximise the DC (Direct Current) capacity and annual solar PV generation under the following considerations:

- Fixed Tilt mounting systems for systems under 3MW and Single Axis tracking systems for systems over 3MW for optimal LCOE (Levelised Cost of Energy)
- Optimal module row spacing to ensure nil shading from 9-3pm during the winter solstice to reach maximum system yield
- Placement of module tables and inverter station optimised to reduce DC and AC (Alternating Current) cable runs.
- 30-degree tilt and northern orientation for all systems to maximise solar exposure and energy generation
- 660W Tier-1 monocrystalline bifacial modules to ensure highest efficiency to reach DC capacity within smallest footprint
- Minimum 10m setback from perimeter fencing for maintenance vehicle access.

Overall, as there is no site-specific information at this stage the designs are indicative only. Further alignment with site-specific assessments detailed in the next section would need to be taken for actual installations.

Detailed Site Considerations

The following activities are typical of grid scale PV installations prior to embarking on a full design and construction scope to mitigate and understand key project risks. These items, outlined below, are standard for most ground mount solar farms and can account for as much as 10-30% of the total installation capital costs. The costs are discussed further in Section 3.3.3 and are based on real world project experience.

Critical Path Items

- DNSP Grid Connection enquiry, AEMO enquiry and ARENA grant funding EOI (Expression of Interest) submission
- Local Council engagement & Development Approval (to be confirmed)
  - Impact assessments
  - Flora & Fauna study & native vegetation
  - Cultural heritage study
- Geo-Technical Surveys and Site Investigations
  - On-site infrastructure inspections and audits
  - Site surveying (drone)
  - Soil testing & pile tests

Development Approval Activities (Typical):

- Traffic management & roads enquiry
- Visual Impact study
- CASA, Glint & Glare studies (if required)
- Fire services requirements (if required)
- Hydrology and flood studies
- Noise assessment

Grid Connection & Design Activities (Typical):

- Preliminary design, engineering, and power system studies
- Preliminary enquiry submission to DNSP
- Preliminary AEMO enquiry to be included within the preliminary connection assessment

Civil Activities (Typical):

- Survey of easements
- Boundary reestablishment
- Electrical resistivity
- Test Pits
- Pile driveability and pull testing
- Shrink and Swell test
- Pre-drill / backfill testing

Component Selection

PV Modules:

660W bifacial modules were selected which currently provide the largest wattage available.

The use of bifacial modules also increases system generation through backside power gains which optimises the project's overall LCOE and prolongs the design life of the system (30-year performance warranty for bifacial modules vs 20-year for monofacial).

A minimum 3% increase in yield can be achieved when utilising bifacial modules depending on the albedo factor (coefficient of the solar irradiation reflected by a typical ground covering). Whilst within typical simulations an albedo factor of 0.2 is used, this can vary between 0.15 to 0.25 depending on the climatic conditions and the type of ground covering (grass or bare soil etc.).

Fixed tilt mounting system:

We have proposed a mounting system within the solution for systems under 3MW. We have used a north facing mounting configuration with 25-degree single-post tilt frame. This tilt angle will provide the maximum system generation as it caters to the system location/latitude. A double post system versus a single post system has been included due to the wind loading requirements.

Single-Axis tracking system:

For systems above 3MW, we have selected a tracking system for improved overall LCOE.

A leading supplier has been selected as the single axis tracking supplier.

String inverters:

For systems that are 1MW or less string inverters are used as central inverter sizes are only available at 2MW+. String inverters have an added benefit of reducing the risk of overall system downtime due to failure, as if one string inverter fails most of the system can still remain online whereas for central inverter systems, when the inverter fails, the whole system will be offline.

Central inverters:

The central inverters would be housed in a containerised Medium Voltage Power Station (MVPS / PCS), which includes an MV transformer and associated switchgear housed within a 20-foot-high container.

3.3.2 Installation References Guides and Standards

Design and installation standards are largely referenced by a suite of Australian Standards and include a wide range of requirements such as general electrical wiring rules, PV specific installation requirements, safety requirements, structural requirements and inverter installation. While the Australian Standards provide a solid foundation for PV system installation requirements, they do form a minimum standard and are concerned mainly with safety. In the context of this analysis and resulting recommendation, standardisation of PV system design and performance also need to be considered. Further, given the coverage required for a PV measure will include a method of standardising energy generation calculations, we must look beyond the available Australian Standards.

The Clean Energy Council (CEC) have been an authority in the PV design, supply and installation industry – while not mandatory, PV system design and installation by a CEC accredited company has long been required if consumers wish to participate in small scale generation certificates, which provides cost rebates. In the past this has made the decision to purchase a PV system much more financially attractive and as a result CEC accreditation has become widespread and very well known in the PV industry.

3.3.3 Results

PV System Location (front of vs behind the meter)

The capital cost estimates for each system are based on the notional design location described. Given their significance and importance for the analysis, development and preliminary costs for the grid scale PV systems have been provided as a separate cost item. These have then been plotted as a minimum and maximum to illustrate the anticipated range for the gride scale PV costs as not all preliminary activities apply to every scenario. However, in practice it is an appropriate estimate to assume actual costs could be the average between minimum and maximum figures for a system of a given size.

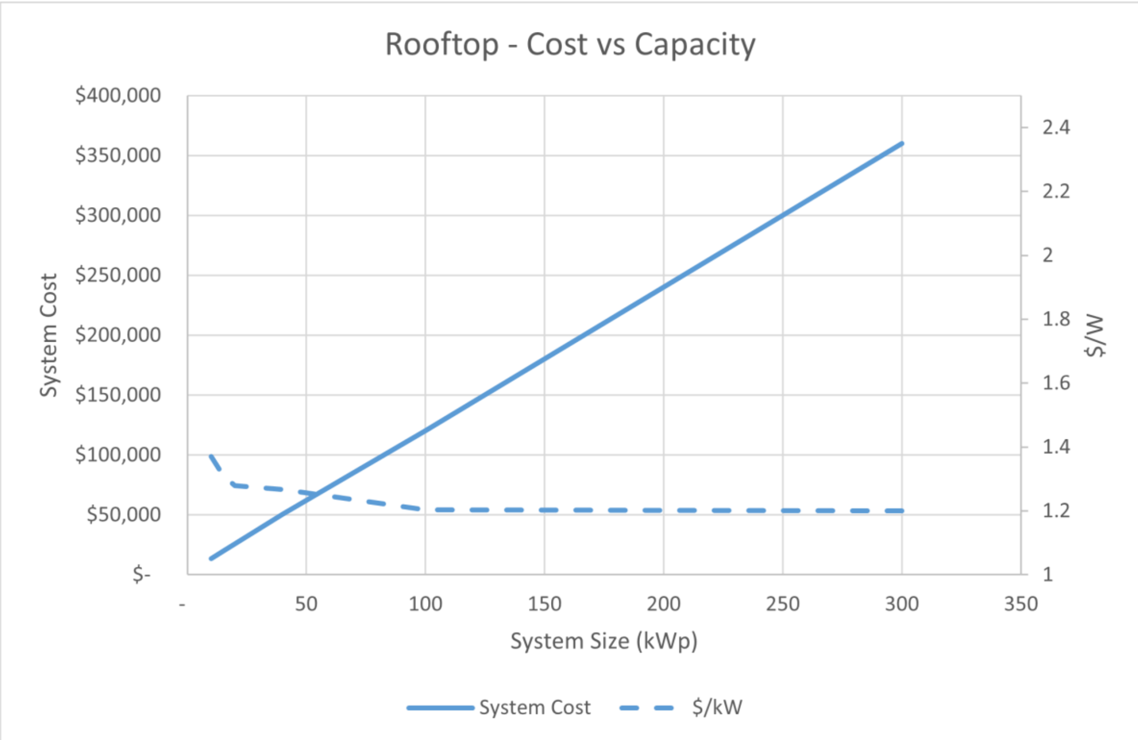


Figure 9: Cost vs Capacity for Rooftop Solar PV Installations

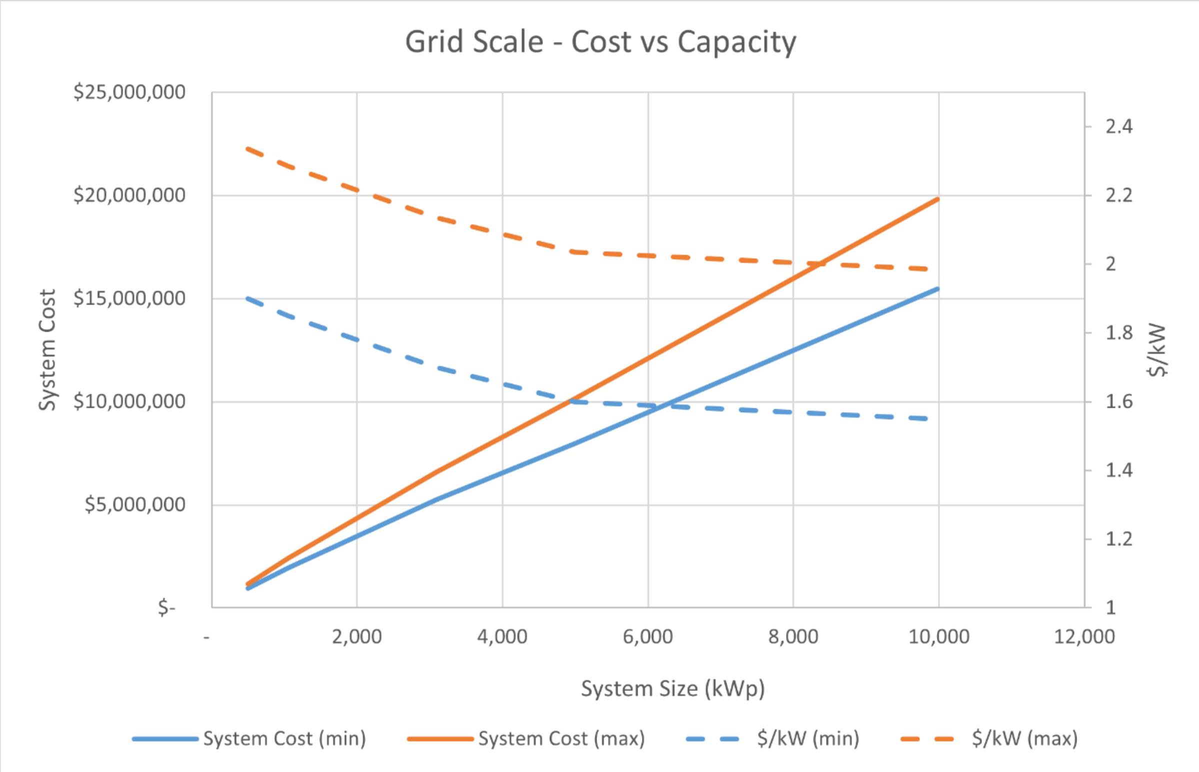


Figure 10: Cost vs Capacity for Grid Scale Solar PV systems

To compare the relative generation yield for each system (noting that, for example, the largest grid scale systems incorporate tracking systems and therefore provide improved yield per kWp of installed capacity) over its expected lifecycle (for a 20 year period), the installed capital cost per MWh of electricity generated for each individual system was plotted.

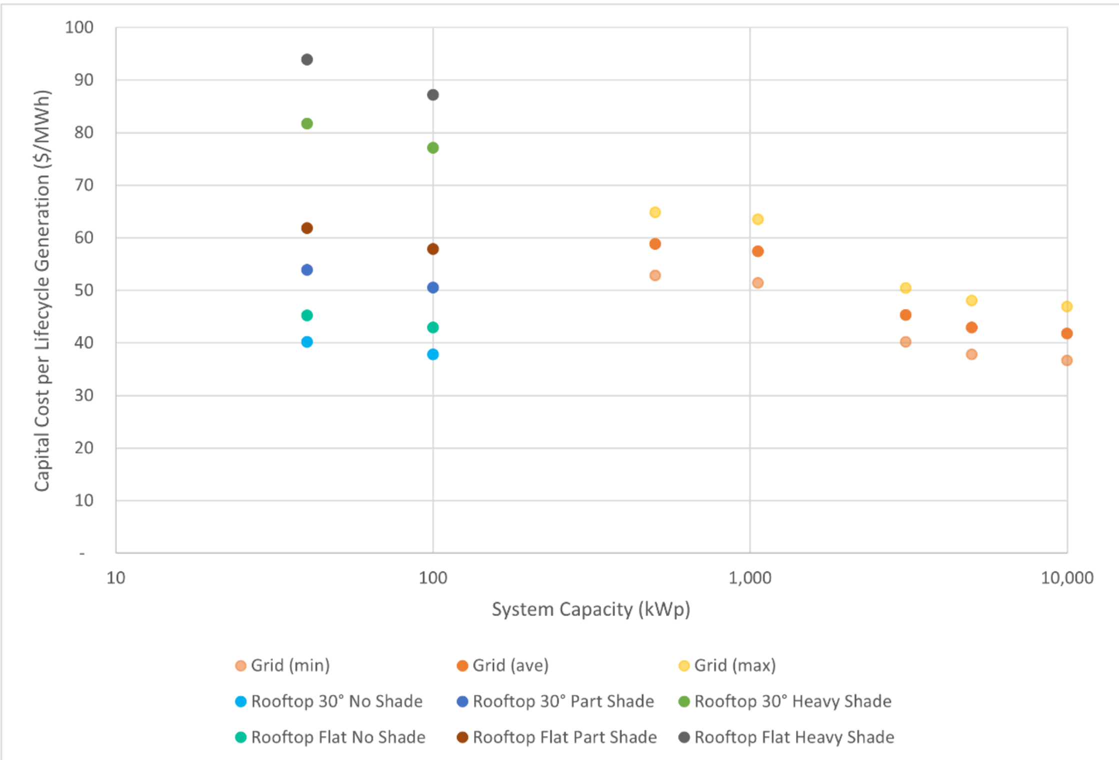


Figure 11: System Capital Cost per MWh of Lifecycle Generation for Rooftop and Grid PV

3.3.4 Discussion

Cost comparison

The cost per kW of installed capacity shows rooftop systems are more cost effective than the grid scale systems. The largest grid scale systems suggest that as system sizes continue to increase the per kW cost may be comparable to the rooftop systems, however systems larger than 10MWp are not as common as the range assessed. It is likely the fixed costs of the grid scale systems (land preparation, connection and development costs, assessments, etc) are the key driver to the higher unit costs when compared to rooftop PV.

Yield comparison

Once yield is accounted for in the comparison, as can be seen by Figure 11, the adjustment for the improved electricity generation provided by the tracking equipment (associated with the larger grid scale PV systems) makes these systems much more competitive with the cheaper rooftop systems. However, given a range of install costs has been provided (minimum and maximum) to account for variability in site conditions, it must be assumed that for comparison purposes the costs for grid scale PV is the 'average' between the two price points. This adjustment identifies that the unshaded rooftop PV systems are approximately as cost effective at a societal level as the largest grid scale PV systems with tracking equipment.

References in Code

As outlined in Section 3.3.2 the Clean Energy Council is a well known and overarching accreditation body in the PV industry. Accredited installers must carry out design and installation in compliance with CEC guidelines. CEC guidelines also provide appropriate and easily recognised documents to reference in code:

- System design must be carried out by an accredited designer, and the estimated yield must be calculated using a method defined by *Clean Energy Council Grid-Connected Solar PV Systems – Design Guidelines for Accredited Installers.*
- System installation must be undertaken by an accredited installer in accordance with *Clean Energy Council Grid-Connected Solar PV Systems: Install and Supervise Guidelines for Accredited Installers*, which has multiple benefits:
    - It provides good coverage of the suite of Australian Standards, which includes reference to AS/NZS 3000 ("The Wiring Rules").
    - It mandates compliance with the *relevant electrical service and installation rules for the state where the system is installed*, including Network Service Provider requirements.

Stringency Basis – Use of Rooftop PV

It is also clear from Figure 11 that the performance of rooftop systems rapidly deteriorates in the presence of shading. Therefore, the stringency for this measure can be set on the basis of requiring the use of *unshaded* PV. This will require definition in Code text.

Stringency Basis – Amount of PV

Having established a societal level stringency, it is necessary to also impose the lens of what amount of PV is reasonable to install at site level. This is driven by cost-effectiveness at site level, with a particular focus on the reduction in revenue that occurs as the installation tends toward export rather than on-site use.

This analysis has been undertaken using a 20 year array lifespan and an assumed annual maintenance cost of $8 per 250W panel up to 40kW, decreasing to $6/kW at 100kW and $4/kW at 300kW. Results are presented in Figure 12.

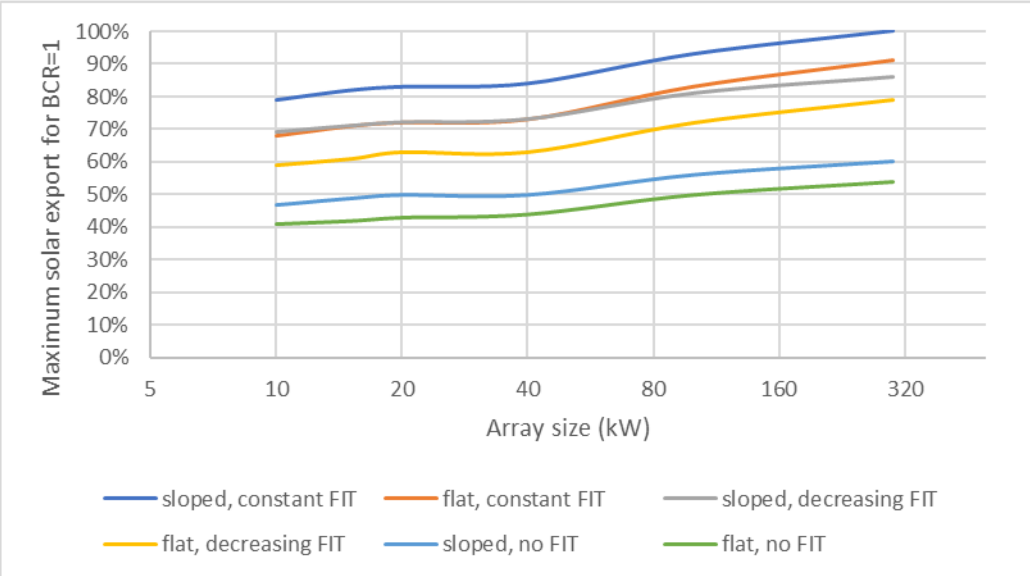


Figure 12. Maximum solar export from PV arrays for a benefit cost ratio of 1 under a range of Feed-in-tariff (FIT) scenarios, for sloped and flat installations.

It can be seen that the extent of export possible while maintaining cost-effectiveness depends significantly on the feed in tariff assumptions, with a relatively small dependence on array size. A simplistic and broadly conservative interpretation of the graph would be that 50% export should be set as the maximum. This delivers cost-effective performance in all non-zero FIT cases and in many zero FIT cases.

Stringency Basis – PV Equipment Technologies

To assist in preventing the use of poor quality equipment technologies that stand to undermine the intent of this measure it is necessary to provide reference to simple technology metrics. The primary equipment of concern is panel and inverter efficiencies:

- PV Panels: Require a panel efficiency low enough to enable the use of flexible panels, for curved roof installations or where traditional glass mount panels can't be installed. For example: inadequate structural loadings, or architectural roofs that don't use traditional sheet metal/tin roofs.
- Inverters: Require inverter efficiency that is sufficiently high to avoid the use of sub-standard equipment, while still enabling participation by a large number of manufacturers.

Stringency Basis – Minimum System Capacity

Table 11 provides the results from the analysis which determines the PV system capacities for each of the core archetypes at which 50% export is achieved. The PV output was applied to consumption for each climate zone, and adjusted until the resulting 50% export is achieved.

Table 11: PV system capacity as a function of building conditioned area at which 50% export is achieved. Results are

CZ	Archetype C5OL (Wp/m^2)	Archetype C5OM (Wp/m^2)	Archetype C5 Average (Wp/m^2)	Archetype C9A (Wp/m^2)	Archetype C9AS (Wp/m^2)	Archetype C9 Average (Wp/m^2)
1	89	98	95	55	81	70
2	63	67	65	32	49	40
3	58	65	60	32	49	40
4	58	61	60	31	44	35
5	72	69	70	35	49	40
6	62	65	65	32	44	40
7	57	59	60	29	46	40
8	55	56	55	28	46	35

Averaging and rounding the results from each archetype group (day and night archetypes) results in, on average, a Wp/m^2 within 10% of the results for each specific archetype. Further, this also results in a number of climate zones with equivalent minimum PV system capacities, making implementation in code more streamlined and simple. Section 3.5.1 includes the results reduced in to code text.

3.4 Battery

3.4.1 Scenarios Summary

The economics of battery storage systems are much more nuanced than the solar PV systems. Revenue streams are much more widely varied and dependent on owner/investor requirements. In commercial buildings this is likely to be limited to:

- Storage of excess solar generation
- Participating in FCAS (Frequency Controlled Ancillary Services) via an aggregator or VPP (Virtual Power Plant).

The battery market is less mature than the PV market, and costs are high, resulting in relatively few installations at commercial level. By contrast, there is significant uptake – and some very large investments – in battery technology at grid scale. In practice, grid scale batteries also have access to a wider range of revenue streams than behind the meter batteries, but for the purpose of this analysis the implications of this have been ignored; instead, the primary analysis question is taken to be whether it is beneficial at a societal level to install batteries behind the meter by comparison to grid scale batteries. To test this, a range of notional designs for behind the meter and grid scale batteries has been developed to enable price comparison on the assumption of comparable societal benefit per unit of storage.

A range of different battery chemistries are available today, and are described in detail in Appendix A: PV/Battery Analysis. Lithium-ion are currently the most common battery available in the market today and is anticipated to remain as such over the coming years. For this reason, all scenarios presented make use of lithium-ion battery chemistry.

3.4.1.1 Behind the Meter

We have developed a range of typical behind the meter battery design options, from small to large. In relation to the wider battery market, commercial buildings exist on the cusp between residential batteries and large scale grid level batteries. As such, we present battery options for both systems. Examples of these options are detailed in this section.

Commercial

Figure 13: Tier 1 Battery Energy Storage System (BESS)

This option forms the basis of our design and is a fully-integrated system including Power Conversion system (PCS), Battery, HVAC, Fire detection, fire suppression system and battery management. It's a scalable and modular design in an outdoor-rated enclosure for easy installation & commissioning.

It is composed of:

- A PCS (Power Conversion System, i.e. Transformer)
- 50kW modularity
- Standard blocks of 50,100, 250 and 500kW.
- Batteries Racks
- Lithium-ion Phosphate batteries
- Standard Rack of 108kWh.

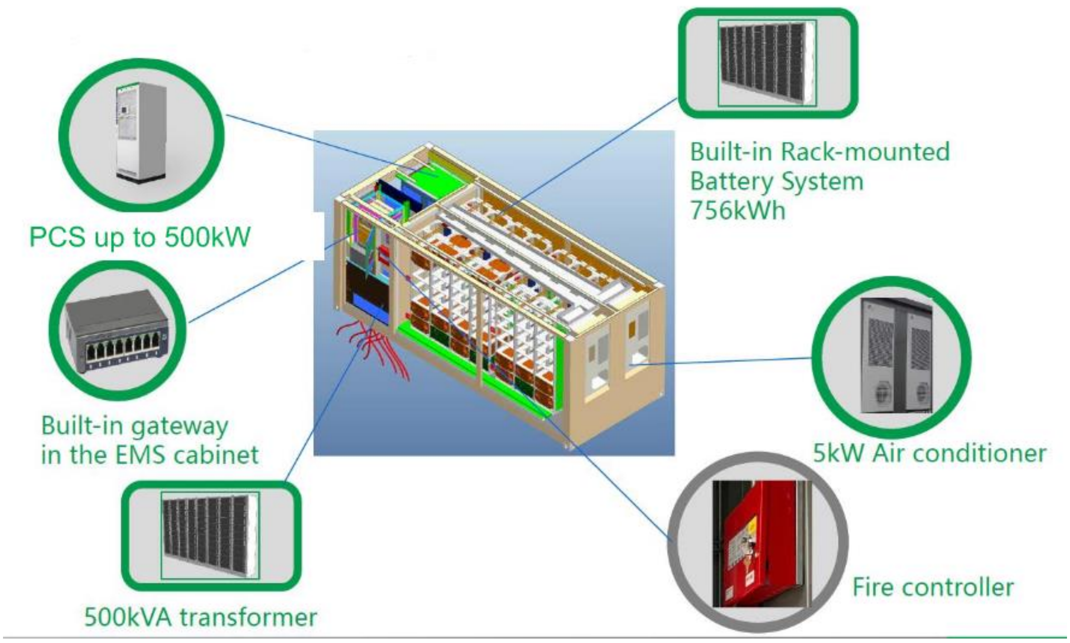


Figure 14: Components

The Power conversion system, battery module capacity, standard rack capacity (108kWh) and other associated systems result in standard container sizes as follows:

Table 12: Commercial BESS sizes

Battery Storage System Size	Container Size
Up to 400 kWh Battery Storage System	10ft container
Up to 1000 kWh Battery Storage System	20ft container

Residential

At scales less than 100kWh, it is typical for a commercial installation to incorporate multiples of residential style batteries, which individually range from 10-20 kWh each. While essentially simpler and smaller than the large-scale batteries, there are some common components, such as power conversion systems and on board controls. These batteries are, however, much more compact and are commonly wall mounted.

Figure 15: Commercial battery installation[9]

3.4.1.2 Grid Level

For this assessment, a lithium-ion battery energy storage systems (BESS) was selected which offered overall value for money and flexible sizing.

Figure 16: Typical BESS

The BESS sizes and models we have assumed for the notional design is as follows.

Table 13: Grid Level Battery Designs

BESS	SIZE	DURATION
1 x HV	250 kW / 500 kWh	2 hours
2 x HV	500 kW / 1 MWh	2 hours
4 x HV	1 MW / 2 MWh	2 hours
MV	2.2 MW / 4 MWh	1.82 hours
MV	2.2 MW / 4 MWh	1.82 hours
MV	2.2 MW / 4 MWh	1.82 hours
2 x UX / MV	4.4 / 8 MWh	1.82 hours

[9] BSL Batt, 2022, BSL Battery website, accessed 22 May 2023, https://www.bsl-battery.com/best-solar-battery-manufacturers-top-brands.html

Lithium-ion battery technologies currently have the best energy density and technological maturity, and ability to respond to fast-response energy markets and largest supplier choice compared to other battery technologies and are therefore the most common BESS chemistry on the market. However other battery technologies such as Vanadium Flow, Sodium Sulphur etc, may be more cost effective at larger scales and longer durations (2MW+).

The same preliminaries (such as detailed site condition assessments, development applications and grid connection approvals) considered in the grid scale PV assessment in Section 3.3.1.2 apply to grid scale BESS. However, due to their much smaller footprint and high-cost relative to PV systems, the proportion of capital required for grid scale BESS preliminaries is much less: typically in the order of 5-15% of total project cost.

3.4.2 Results

The costs for typical battery installations behind the meter and at grid level were compared and converted to a $/kWh metric for comparison purposes. To illustrate the comparison on a single chart, the x-axis is shown as a logarithmic scale.

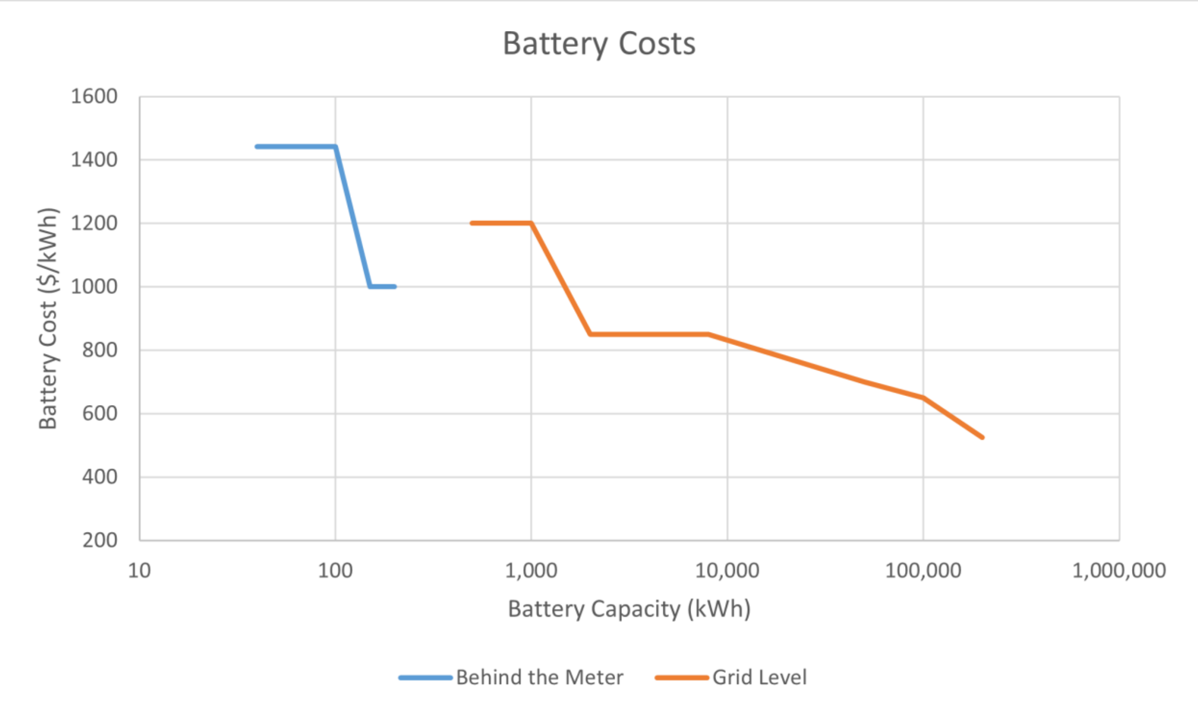


Figure 17: Battery Cost Behind the Meter and Grid Level Expressed as $/kWh

3.4.3 Discussion

The results show a general trend for battery installations to become more cost effective with increasing capacity, as expected. The result that was less foreseeable was the irregularity of storage capacities costs in the 100-2,000kWh range. On further investigation this was found to be due to the battery technologies used, the modularised solutions available, and the market forces for battery components and materials – this capacity range is considered as commercial and small utility scale. For grid level batteries <2,000kW there is competition for materials from primarily larger utility scale batteries. These 'smaller' systems are also less common at grid/utility scale. Further, similarly to the grid scale PV systems assessed, there are fixed costs imposed on these systems that the behind the meter scenarios do not bear.

The overall insight showing improved cost effectiveness with increasing capacity at grid scale is clear. The small overlap in cost effectiveness between larger behind the meter battery systems and the smallest grid scale systems is far outweighed by the wide range of lower cost installations seen by the 'tail' of grid scale costs from 2,000 kWh and above. The smaller grid scale systems assessed are uncommon in real world installations and to impose behind the meter installations based on a comparison assessment with these systems would be less appropriate.

Based on this assessment, it is concluded that behind the meter battery installations are not appropriate for inclusion in NCC2025.

3.5 Proposed Measures

3.5.1 PV Systems – Proposed Code Text

J9XX Solar Photovoltaic System Installation

(1) A building must be provided with a solar photovoltaic system installation that –

- *a) Is installed in compliance with the* Clean Energy Council Grid-Connected Solar PV Systems: Install and Supervise Guidelines for Accredited Installers*;*
- *b) Has an AC generation capacity that is larger than or equal to the smaller of:*
  - *i. A solar photovoltaic installation that covers to 100% of the available roof space excluding areas that are:*
    - *(i) Shaded for more than 10% of daylight hours*
    - *(ii) At more than a 45 degree roof pitch relative to horizontal*
    - *(iii) At more than a 10 degrees roof pitch for south facing roofs*
    - *(iv) Structurally inadequate for solar photovoltaic panel installation.*
    - *(v) Used as a terrace, carpark, roof garden, roof/sky light or the like; or*
    - *(vi) Required as trafficable area, access for height safety systems or plant maintenance access; or*
    - *(vii) Used for services installations or the like; or*
    - *(viii) Above exhaust air flows from heat rejection equipment*
  - *ii. A solar photovoltaic installation with peak system output rating as per table J9XX; and*
- *c) For the purposes of the calculations in (b) the following assumptions shall apply:*
  - *i. Solar photovoltaic panels of efficiency ≥18%, and*
  - *ii. Inverter(s) of efficiency ≥96%.*

Table J9XX: Minimum solar photovoltaic system installed peak capacity per m^2 of building conditioned area

Climate Zone	Class 5, 6, 7, 8 Installed Peak System Output W_p/m^2	Class 2, 3, 4, 9 Installed Peak System Output W_p/m^2
1	95	70
2-7	65	40
8	55	35

3.5.2 Batteries

Given the results of the battery analysis showing the grid scale batteries as more cost effective in the vast majority of cases it is not proposed that there shall be any additional requirements for battery installations under NCC2025. The economies of scale for grid level batteries both in the supply market (materials supply and manufacture) and installation make it difficult for behind the meter installations to compete on cost.

Conversely, grid level and behind the meter batteries largely present their own unique set of benefits, which lead to the argument of whether one option prevails over the other. Grid batteries can provide firming of large scale renewables and provide greater benefit to a larger set of end-users while also accessing a wider range of revenue streams. Whereas behind the meter installations provide the potential for a reduction in required investment at the grid level (due to potential avoidance of network capacity) and distribute the benefits more closely to the end users. These benefits have the potential to continue a balanced discussion, however if the economics of the equation were altered by, for example, a significant cost reduction for behind the meter installations or an increased incentive (through access to more valuable revenue streams, or wider range of revenue streams), behind the meter installations may be more competitive in future.

4 Lighting Control

4.1 Background and context

4.1.1 Lighting control applications

Lighting control systems create the ability to alter the lighting system output to suit the needs of individual tasks. With lighting control systems, various benefits can be achieved, such as energy saving, scene setting, increased luminaire lifetime, enhanced convenience and improved safety. Lighting control systems can comprise:

- Manual switches/Manual Dimming.
- Automatic sensing and control components.
- Time control.
- Manual overrides.
- Programmable lighting control system units.

4.1.2 Current Lighting control provisions

NCC2022 has provisions in Clause J7D4 covering lighting control. This includes requirements for:

- Occupancy sensing in Class 3 sole occupancy units (covering lighting and air-conditioning)
- Time-switches and/or motion sensing for 95% of lights in buildings or storeys of greater than 250m², other than class 2, 3 or 4 buildings.
- Daylight dimming for lights adjacent to windows in foyers corridors and circulation spaces

Exceptions are made for situations where security and safety are of paramount concern.

Successful use of daylight sensing is often challenging due to the need for it to be carefully configured and commissioned to ensure proper functioning; minor alterations in space configuration can lead to issues in operation, often resulting in the control being decommissioned. The current NCC2022 measure was intentionally limited to a situation where these challenges are minor. However, expansion of the measure to permanently occupied spaces would carry these identified risks. As a result, this assessment has not considered expansion of daylight sensing requirements for NCC2025.

However, NCC2022 provisions lag a number of increasingly common applications of motion/occupancy sensing in buildings, including toilets, car parks, corridors and (to a lesser extent) open areas in spaces such as offices. As a result, the analysis undertaken here is based around these cases.

4.2 Methodology

The outline methodology is shown in Figure 18.

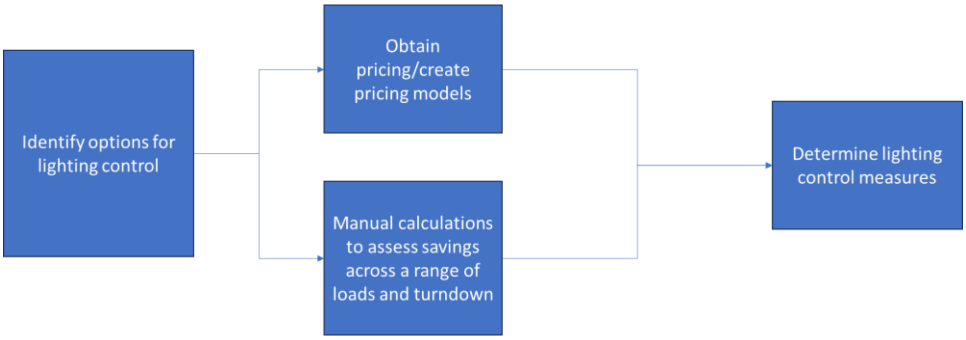


Figure 18. Outline methodology for the lighting control analysis

4.3 Sensor costs and capabilities

A more detailed description of background material informing this section is presented in Appendix B: Lighting Control.

4.3.1 Sensor costs

The cost of controls has been evaluated based on common practice, as listed in Table 14.

Type	Total cost including installation
Manual Switch	$116
Presence/Occupancy sensor	$400
Weatherproof Presence/Occupancy Sensor	$450

Table 14: Light sensor/switch costs

When not connected to a DALI system, the difference in cost between presence/occupancy sensors is principally not the type of sensor, but whether or not it is weatherproof. Time switches were costed but are not an incremental cost in the analyses.

4.3.2 Sensor capability

Based on common products, it has been assumed that sensors have the following capabilities:

1. Presence detection within a 4m x 4m area (16m²). This means the ability to sense a stationary person.
2. Occupancy detection within a 7m x 7m area (49m²). This means the ability to sense a moving person (corresponding to the Specification 40 definition of a motion detector).
3. Where presence detection is used the effective coverage area is approximately 4m x 4m, with actual installations allowing for some sensor overlap to achieve this. The effective coverage area of motion detectors in open spaces is approximately 7m x 7m, which also allows for some sensor overlap.

4.3.3 Open area lighting power density

For the purpose of assessing the potential for open area lighting control using motion sensors, it has been assumed that the lighting power density is $4W/m^2$. This reflects lighting power densities (uncorrected for room factor) for multiple open space types in NCC2022 Table J7D3A. For corridor applications this has been modified to reflect the impact of the room aspect ratio.

4.3.4 Operational modes and assumptions

For the purpose of the analysis, three operational modes have been considered:

1. Mode A:
    a. Base case: time switch control.
    b. Stringency case: Lights are time switched on and off but are controlled by occupancy sensors during the hours that they are time switched on.
2. Mode B:
    a. Base case:
        i. Time switch control during normal hours and manual control out of hours, or
        ii. Time switch control with a 50% chance of having been set to 24/7 for convenience; or
        iii. Time switch control with 50% extended hours coverage to service out-of-hours users; or
        iv. Manual control at all times.
    b. Stringency case: Lights are time switched on and off but are controlled by occupancy sensors during the hours that they are time switched off.
3. Mode C:
    a. Base case:
        i. Manual control, left on all the time; or
        ii. Time switch control, operating all the time
    b. Stringency case: Lights solely controlled by occupancy sensors.

For each of these modes it is necessary to make assertions as to the degree of turndown likely to be achieved. Some guidance in this respect can be taken from Table J7D3b, which lists standardised control factor assumptions for a range of situations. For this analysis, the control factors listed in Table 15 have been assumed.

	Mode	Base Case - In-hours operation	Base Case - Out of hours operation	Occ Sensors – In-hours operation[10]	Occ Sensors - Out of hours Operation[11]
Bathroom	A	1	0	0.4	0
	B	1	0.5	1	0.1
	C	1	1	0.4	0.1
Corridor 3m/5m, Open space	A	1	0	0.6	0
	B	1	0.5	1	0.1
	C	1	1	0.6	0.1
Carpark	B	1	0.5	1	0.1

[10] Taken from Table J7D3b

[11] Asserted based on the scenarios; in essence a low level of occupancy is assumed.

	C	1	1	0.6	0.1

Table 15. Assumed lighting control factors.

The control scenarios listed in Table 16 have been tested.

Scenario	Cases
Toilet lighting (based on wattage)	Mode A, B and C controls
Corridor/open space lighting (4W/m²)	Mode A, B and C controls
Car park (2W/m²)	Mode B and C controls

Table 16: Lighting control scenarios

For each scenario, core operational hours of 2000, 2500, 3000 and 5000 hours have been assessed.

Peak demand is assumed to be reduced by the control factor on a probabilistic basis.

A base load of 2% has been allowed for the operation of sensors.

4.4 Results and Discussion

4.4.1 Bathrooms/locker rooms/rest rooms

The results for bathrooms, locker rooms and rest rooms (shorthanded to bathrooms in this discussion) are presented in Table 17 to Table 19.

	Watts under sensor control (W/sensor)									
Hrs	20	40	60	80	100	120	140	160	180	200
2000	0.20	0.40	0.60	0.80	1.00	1.19	1.39	1.59	1.79	1.99
2500	0.24	0.48	0.73	0.97	1.21	1.45	1.69	1.94	2.18	2.42
3000	0.28	0.57	0.85	1.14	1.42	1.71	1.99	2.28	2.56	2.85
5000	0.46	0.91	1.37	1.83	2.28	2.74	3.20	3.65	4.11	4.57

Table 17. Benefit cost ratios for occupancy sensors in bathrooms, Mode A operation (occupancy sensor enabled for stated hours, lights off outside those hours)

	Watts under sensor control (W/sensor)									
Hrs	20	40	60	80	100	120	140	160	180	200
2000	0.38	0.76	1.14	1.52	1.90	2.27	2.65	3.03	3.41	3.79
2500	0.35	0.70	1.05	1.40	1.76	2.11	2.46	2.81	3.16	3.51
3000	0.32	0.65	0.97	1.29	1.61	1.94	2.26	2.58	2.91	3.23
5000	0.21	0.42	0.63	0.84	1.05	1.26	1.47	1.68	1.89	2.10

Table 18. Benefit-cost ratios for occupancy sensors in bathrooms, Mode B operation (lights time-switched on for stated hours, occupancy sensor enabled outside those hours)

	Watts under sensor control (W/sensor)									
Hrs	20	40	60	80	100	120	140	160	180	200
2000	1.09	2.17	3.26	4.34	5.43	6.51	7.60	8.68	9.77	10.85
2500	1.06	2.13	3.19	4.26	5.32	6.39	7.45	8.52	9.58	10.64
3000	1.04	2.09	3.13	4.18	5.22	6.26	7.31	8.35	9.39	10.44
5000	0.96	1.92	2.88	3.84	4.80	5.77	6.73	7.69	8.65	9.61

Table 19. Benefit cost ratios for occupancy sensors in bathrooms, Mode C (sensors control lights all hours).

It can be seen that the threshold of watts controlled per sensor varies with each case, with the best benefit-cost ratios appearing for Mode C operation, i.e. lighting is under sensor control at all hours. This makes inherent sense and is reflected in the relative energy use of the scenarios, as shown in Figure 19.

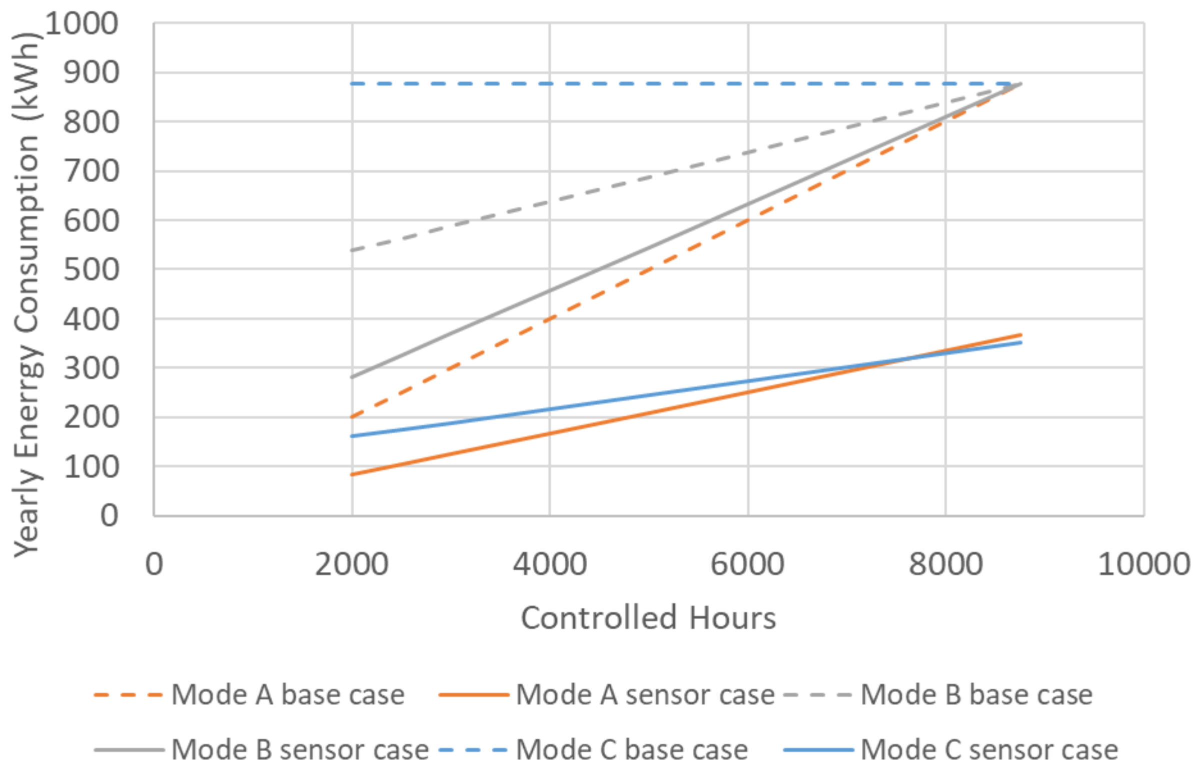


Figure 19. Comparison of energy use for Mode A, B and C cases of bathroom operation based on 100W load under sensor control. Note that in the Mode C base case, lights are always on.

When establishing a measure, however, it is important to contextualise the use of the space. As a first point, it should be expected that any sensor installation other than in a single user space is accompanied by some level of residual lighting to enable way finding. This means that in the event that the sensor fails to detect presence, an occupant will not be left in the dark. With this proviso, it can be seen that Mode C operation would be preferable in most cases. The exception would likely be where a bathroom is expected to be in heavy use, such is in a retail centre, in which case the practical difference in energy use versus a Mode B operation will be small (while the convenience aspect of time-switched lights will be significant).

For operation in Mode A or B, the scale of the load being able to be controlled by a single sensor is paramount to the viability of the measure. To put this in context, the maximum lighting power density for this type of space is 3W/m², modified by room form factors (which would typically increase this figure by a significant amount). At 3W/m², a Mode B sensor installation would require 80W under sensor control to be cost-effective for office-like applications, but 120W for retail applications; these figures can be converted to 27-42m² allowing for 5% of lights to be uncontrolled. Given a nominal control area of 49m², both these scenarios appear cost-effective.

For operation in Mode C, the equivalent area is under 10m², making the result viable in most cases.

4.4.2 Open Space

General open spaces

The results for the use of occupancy sensors in open spaces (assumed lighting power density of 4W/m²) are shown in Table 20 to Table 22.

	Area under sensor control (m² per sensor)									
Hrs	5	10	15	20	25	30	35	40	45	50
2000	0.12	0.23	0.35	0.46	0.58	0.69	0.81	0.92	1.04	1.15
2500	0.14	0.29	0.43	0.58	0.72	0.87	1.01	1.16	1.30	1.45
3000	0.17	0.35	0.52	0.69	0.87	1.04	1.22	1.39	1.56	1.74
5000	0.29	0.58	0.87	1.16	1.45	1.74	2.03	2.32	2.61	2.90

Table 20. Benefit-cost ratios for the use of occupancy sensors in general open space in Mode A operation (sensors enabled during time switched hours)

	Area under sensor control (m² per sensor)									
Hrs	5	10	15	20	25	30	35	40	45	50
2000	0.39	0.79	1.18	1.57	1.96	2.36	2.75	3.14	3.54	3.93
2500	0.36	0.73	1.09	1.46	1.82	2.18	2.55	2.91	3.27	3.64
3000	0.33	0.67	1.00	1.34	1.67	2.01	2.34	2.68	3.01	3.35
5000	0.22	0.44	0.65	0.87	1.09	1.31	1.53	1.74	1.96	2.18

Table 21. Benefit-cost ratios for the use of occupancy sensors in general open space in Mode B operation (lights enabled by time switch during operating hours, and by sensor out of hours)

	Area under sensor control (m² per sensor)									
Hrs	5	10	15	20	25	30	35	40	45	50
2000	1.06	2.12	3.17	4.23	5.29	6.35	7.41	8.47	9.52	10.58
2500	1.02	2.04	3.06	4.09	5.11	6.13	7.15	8.17	9.19	10.21
3000	0.98	1.97	2.95	3.94	4.92	5.91	6.89	7.88	8.86	9.85
5000	0.84	1.67	2.51	3.35	4.19	5.02	5.86	6.70	7.54	8.37

Table 22. Benefit-cost ratios for the use of occupancy sensors in general open space in Mode C operation (sensors enabled all hours)

The results indicate that if time switch control is present, after-hours sensor operation after hours is viable at 15m² per sensor (Mode B), while daytime (Mode A) operation of sensors is viable at 30m² per sensor at 3000 hour pa occupancy and 20m² at 5000 hour pa occupancy. Sensors as the sole form of control (Mode C) is viable down to less than 10m² per sensor.

Again, it is important to contextualise the operation of sensors to the spaces that may be involved. For offices for instance, occupants are often stationary and as a result presence detection is required, limiting the sensor area to 16m²; with this limitation either Mode B or C operation are viable, albeit marginally. For retail spaces, however, operation by sensor during operating hours is undesirable, so only Mode B can be considered.

Corridors

A special case of open area lighting control is for corridors. These spaces have inherently transitory occupancy and thus are capable of being occupancy rather than presence sensed; furthermore, the room form factor of corridors will tend to result in higher lighting power density figures. Conversely, however, the area controlled by an individual sensor is better expressed as a length as the sensing capability beyond the width of the corridor is unused.

	Length of corridor under sensor control (m per sensor)								
Hours	**3**	**3.5**	**4**	**4.5**	**5**	**5.5**	**6**	**6.5**	**7**
2000	0.45	0.52	0.60	0.67	0.75	0.82	0.90	0.97	1.04
2500	0.54	0.64	0.73	0.82	0.91	1.00	1.09	1.18	1.27
3000	0.64	0.75	0.85	0.96	1.07	1.17	1.28	1.39	1.50
5000	1.03	1.20	1.37	1.54	1.71	1.88	2.05	2.22	2.40

Table 23. Benefit-cost ratios for a 3m wide corridor in Mode A operation (sensor enabled by time switch during occupancy hours)

	Length of corridor under sensor control (m per sensor)					
Hours	**3**	**3.5**	**4**	**4.5**	**5**	**5.5**
2000	1.30	1.52	1.74	1.95	2.17	2.39
2500	1.20	1.41	1.61	1.81	2.01	2.21
3000	1.11	1.29	1.48	1.66	1.85	2.03
5000	0.72	0.84	0.96	1.08	1.20	1.32

Table 24. Benefit-cost ratios for a 3m wide corridor in Mode B operation (sensor operates outside time-switched hours)

	Length of corridor under sensor control (m per sensor)					
Hours	**0.5**	**1**	**1.5**	**2**	**2.5**	**3**
2000	0.58	1.16	1.74	2.33	2.91	3.49
2500	0.56	1.12	1.68	2.25	2.81	3.37
3000	0.54	1.08	1.62	2.16	2.70	3.25
5000	0.46	0.92	1.38	1.84	2.30	2.76

Table 25. Benefit-cost ratios for a 3m wide corridor in Mode C operation (sensor control operation all hours).

The results indicate the for a 3m corridor, operation in Mode B or C is viable. Results improve for wider corridors, but the fundamental result is similar.

Again, the contextualisation of this result is that certain public corridors are preferably time switch controlled during hours of public access, while back of house and private corridors are capable of being controlled on occupancy sensor at all times.

4.4.3 Car Parks

For car parks, only Mode B and C operation have been considered.

	Area controlled by sensor (m^2 per sensor)									
Hours	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**
2000	0.22	0.45	0.67	0.89	1.11	1.34	1.56	1.78	2.01	2.23
2500	0.21	0.41	0.62	0.83	1.03	1.24	1.44	1.65	1.86	2.06
3000	0.19	0.38	0.57	0.76	0.95	1.14	1.33	1.52	1.71	1.90
5000	0.12	0.25	0.37	0.50	0.62	0.74	0.87	0.99	1.11	1.24

Table 26. Benefit-cost ratios for sensor control of car park lighting in Mode B (lighting time switched on during operating hours and controlled by sensors out of hours)

	Area controlled by sensor (m² per sensor)									
Hours	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**
2000	0.60	1.20	1.79	2.39	2.99	3.59	4.18	4.78	5.38	5.98
2500	0.58	1.15	1.73	2.31	2.88	3.46	4.04	4.62	5.19	5.77
3000	0.56	1.11	1.67	2.22	2.78	3.34	3.89	4.45	5.00	5.56
5000	0.47	0.94	1.42	1.89	2.36	2.83	3.31	3.78	4.25	4.72

Table 27. Benefit-cost ratios for sensor control of car park lighting in Mode C (sensor control lights at all hours).

For car parks it can be seen that car park lighting in areas with short operating hours is cost effective but not for longer hours spaces; this particularly impinges upon retail car parks. However, lighting control by solely sensor is viable in all spaces, provided that such control is appropriate to user expectations[12].

4.5 Discussion

The common themes in the scenarios investigated are that:

1. In public areas, the preferred operation includes time-switched operation during normal access hours with sensor operation out of hours. The exception is carparks with long operating hours, for which occupancy sensor operation beyond core hours may be uneconomic.
2. In non-public areas, the preferred operation is for lighting to be controlled by occupancy sensors at all times. There are some exceptions where sensing requirements to achieve satisfactory operation would become too intense.

Given the range of subtleties in the above, the structure of a measure needs to be sufficiently flexible to allow for contextualised interpretation. Furthermore, the expression in Code should not rule out the opportunity to use Mode A operation should the designer consider this to be appropriate (although the risks of this needs to be managed, as lack of after-hours lighting control can lead to time switch hours being extended).

Furthermore, while this discussion has focussed on occupancy sensors, the opportunity to use other forms of demand-based control, such as run-on timers – should not be ruled out.

The proposed measure has therefore been structured to respond to these multiple demands.

4.6 Proposed Code Text

Specification NN

(1) For the purpose of this specification the following definitions shall apply

a. Public space means any space which an average member of the public has access to the space. This includes shops, malls, building entry foyers and public car parks during the hours in which they can be accessed by the public, and a convention centre or entertainment/sporting venue during the times at which the facility is open for an event. It also includes patient/resident accessible areas of class 9A hospitals and class 9c Aged Care facilities at all times.

[12] In a public car park, for instance, sensor-only control is unlikely to be acceptable to users for perceived and real security reasons, while for a private car park sensor-only control is reasonable.

b. *Controlled occupancy space means any space in which only specified users have access to the space. This includes the student accessible areas of schools, the guest accessible areas of hotels and the common areas of Class 2 buildings, office areas and occupied spaces accessible by general employees of a tenant or occupant of the building.*
c. *Normal operating hours means the normal hours in which:*
    i. *The public have access to a public space*
    ii. *Specified users of a controlled space normally occupy that space*
d. *Extended operating hours means the hours beyond normal hours in which*
    i. *Public do not have access to a public space, but that space may be operating as a controlled occupancy space*
    ii. *Specified users of a controlled space may irregularly occupy that space*
e. *Closed hours means the hours beyond normal hours and extended hours in which*
    i. *The space is locked; and/or*
    ii. *Only security staff are present in the space*
f. *Regular occupancy means that the space is expected to be continuously occupied at most times to a density of greater than 1 person per 40m² or passed through at least once every 15 minutes. All other spaces are considered to be irregular occupancy*
g. *Mode A control includes manual switches, time switchess, occupancy sensors and lighting timers*
h. *Mode B control includes occupancy sensors and lighting timers only*
i. *Mode C control includes occupancy sensors only*

(2) *Mode A controls shall be used in spaces during the following situations*
    a. *Public spaces in regular occupancy*
    b. *Controlled occupancy periods in regular occupancy during normal operating hours*

(3) *Mode B controls shall be used during the following situations*
    a. *Public spaces, or parts thereof, with irregular occupancy within normal operating hours*
    b. *Controlled spaces, or parts thereof, with irregular occupancy within normal operating hours*
    c. *Any space in extended operating hours*

(4) *Closed spaces:*
    a. *Without on-site security staff in attendance shall have all lights switched off*
    b. *With on-site security staff in attendance shall be controlled in Mode C*

5 Peak Demand Management

5.1 Background and context

This measure considers the standardisation of some possible behind-the-meter demand management methods as well as participation in grid demand events for the potential revenue streams available.

5.1.1 Behind the meter demand management

A site's demand for grid electricity varies depending on the operation of the building and changes to renewable energy (if installed) generated on site. If the HVAC services are intelligently operated and suitably managed, electricity demand from the grid can be temporarily reduced or time shifted. The intention is to smooth the site's electrical demand load profile.

This can generally be achieved by one or more of the following:

a) Permitting thermal conditions within the building to drift within tolerance levels
b) Using on site storage (battery or thermal chilled water storage)
c) Using on site generation with synchronisation equipment

The monetary value of this style of management is effectively just an opportunity cost which is a function of the site's electricity tariff.

5.1.2 Grid demand events

Grid demand events occur when there is a grid level shortfall in generation relative to the load, either because of excessive demand or because of short-term deficiencies of generation. These events are a potential source of revenue for participants if they can reduce their demand within the required timing and for the duration of the event.

The reduction in demand is defined as the change in power draw at the connection point to the electricity grid (i.e., the NMI meter). As the magnitude of the demand response cannot be measured directly, it is estimated by comparing the actual load profile with a prediction of what would have occurred if the site did not respond. The predicted load profile, referred to as the baseline, is estimated using the site's historical consumption (typically between the most recent 4 – 10 qualifying days). The exact number of days depends on the nominated AEMO baseline methodology.

There are several different types of grid demand event as summarised below:

Table 28: Grid demand events

Grid Demand Events	Description	Expected Event Frequency, Duration & Response Time
Reliability and Emergency Reserve Trader (RERT)	The Reliability and Emergency Reserve Trader events are signalled by a forecasted shortfall in energy reserves, typically when there's a combination of hot/ extreme weather, high demand, generation, or transmission outages. RERT events are enacted by AEMO and are infrequent.	Frequency: Low (1 - 3 times each year) Duration: 3 – 6 hours Response time: < 120 mins
Wholesale Demand Response (WDR)	These are events that are signalled by a spike in the spot price of electricity. These are typically based on the Wholesale Demand Response Mechanism (WDRM).	Frequency: Moderate (5 - 20 times each year) Duration: Variable (depend on the settings selected by the demand responder. Response time: < 30 mins
Frequency Control Ancillary Services (FCAS)	These are events that are signalled by a frequency outside the preferred control range and are fast response events of short duration (10mins or less).	Frequency: High (1-3 times each month) Duration: 3 – 6 hours Response time: < 120 mins

5.2 Introduction to tariffs

5.2.1 Network tariffs

Network tariffs are set by a Distribution Network Service Provider (DNSP). Each jurisdiction may have several DNSPs operating and Figure 20 shows a summary. To cover the cost of providing, operating and maintaining the distribution network, each DNSP establishes a cost base. The method of price-setting of the network tariff is complex and the pricing principles are set out in the National Electricity Rules[13] for all networks other than Western Power. The key clauses are summarised in Table 29 below. Within these rules, the DNSP translates them into a set of pricing objectives.

[13] NER Clause 6.18.5

Table 29: Network pricing principles - NER Clause 6.18.5.

6.18.5 – Pricing Principles	Network Pricing Objective
6.18.5(a)	The tariffs that DNSP charges should reflect the efficient costs of providing those services to the retail customer.
6.18.5(e)	For each tariff class, the revenue expected to be recovered must lie on or between: • an upper bound representing the stand-alone cost of serving the retail customers who belong to that class; and • a lower bound representing the avoidable cost of not serving those retail customers.
6.18.5(f)	Each tariff must be based on the long-run marginal cost (LRMC) of providing the service to the retail customers assigned to that tariff.
6.18.5(g)	Each tariff must reflect the efficient costs of serving customers in a way that minimises distortions to price signals for efficient usage.
6.18.5(h)	A DNSP must consider the impact on retail customers of changes in tariffs from the previous regulatory year.
6.18.5(i)	The structure of each tariff must be reasonably capable of being understood by customers.
6.18.5(j)	A tariff must comply with all applicable regulatory instruments.

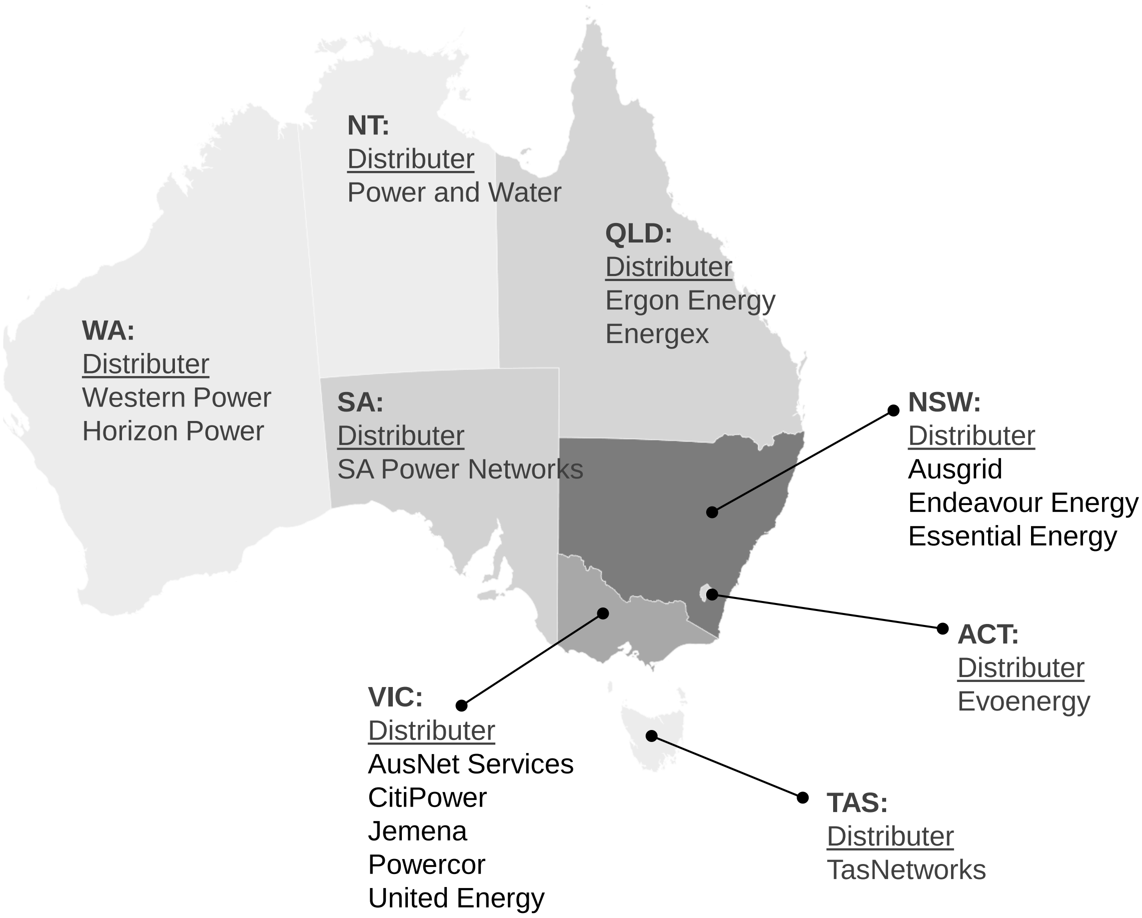


Figure 20: Summary of the range of DNSPs by jurisdiction.

Table 30 below shows the typical network charges for **non-residential low voltage users** for the 2021-2022 period. Of particular interest is the fact that while the method of price determination is consistent, due to variation in the underlying network operating cost, there is no geographic consistency in the resulting tariff price.

Table 30: Non-residential low voltage minimum, average and maximum 2021-2022 network tariff prices (NUOS - Network Use of Service). Prices include GST. Source: Pricing Proposals for 2021 – 2022 for each DNSP available on the AER website[14].

State	Business Size	Min. Network Supply Charge ($/day)	Average Network Supply Charge ($/day)	Max. Network Supply Charge ($/day)	Min. Network Energy Consumption Charge (c/kWh)	Average Network Energy Consumption Charge (c/kWh)	Max. Network Energy Consumption Charge (c/kWh)	Min. Network Demand Charges ($/kW/month)	AverageNetwork Demand Charges ($/kW/month)	Max. Network Demand Charges ($/kW/month)	Min. Network Demand Charges ($/kVA/month)	AverageNetwork Demand Charges ($/kVA/month)	Max. Network Demand Charges ($/kVA/month)
NSW	**Business (All)**	0.58	7.50	28.06	1.97	7.25	15.30	0.32	3.81	11.22	0.12	7.24	12.25
NSW	Business-Small/Medium (<160 MWh pa)	0.58	1.73	5.36	2.08	8.12	15.30	0.32	3.81	11.22	6.68	6.68	6.68
NSW	Business-Large (160 - 750 MWh pa)	4.74	16.64	24.91	2.09	6.01	13.55	-	-	-	1.86	7.86	12.25
NSW	Business-Very Large (>750 MWh pa)	26.79	27.43	28.06	1.97	3.75	5.53	-	-	-	0.12	5.67	11.22
VIC	**Business (All)**	0.30	5.89	40.85	2.02	7.78	25.13	3.69	6.58	12.81	2.54	10.42	20.08
VIC	Business-Small/Medium (<160 MWh pa)	0.30	0.77	3.29	4.65	9.73	22.10	3.69	6.58	12.81	0.00	0.00	0.00
VIC	Business-Large (160 MWh - 750 MWh pa, or > 120kVA)	0.30	4.39	17.08	2.02	7.13	25.13	-	-	-	2.65	10.18	14.20
VIC	Business-Very Large (> 750 MWh pa)	14.08	23.55	40.85	2.44	2.68	3.05	-	-	-	2.54	10.68	20.08
SA	**Business (All)**	0.56	112.54	581.46	5.24	7.98	18.01	-	-	-	2.41	7.91	15.89
SA	Business-Small (< 160 MWh pa)	0.56	0.56	0.56	8.89	11.41	15.01	-	-	-	2.41	5.50	8.60
SA	Business-Large (> 160MWh pa)	0.56	142.01	581.46	5.24	6.65	18.01	-	-	-	5.52	8.22	15.89
QLD	**Business (All)**	0.47	89.15	936.66	0.39	9.03	32.68	0.62	22.48	72.04	2.52	24.71	64.84
QLD	Business-Small Business (<100 MWh pa)	0.47	1.44	3.44	3.92	13.91	32.68	0.62	4.52	12.06	2.90	2.90	2.90
QLD	Business-Large Business (>100 MWh pa) ^	5.18	176.86	936.66	0.39	3.96	14.77	3.83	31.94	72.04	2.52	26.96	64.84

[14] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs

State	Business Size	Min. Network Supply Charge ($/day)	Average Network Supply Charge ($/day)	Max. Network Supply Charge ($/day)	Min. Network Energy Consumption Charge (c/kWh)	Average Network Energy Consumption Charge (c/kWh)	Max. Network Energy Consumption Charge (c/kWh)	Min. Network Demand Charges ($/kW/month)	AverageNetwork Demand Charges ($/kW/month)	Max. Network Demand Charges ($/kW/month)	Min. Network Demand Charges ($/kVA/month)	AverageNetwork Demand Charges ($/kVA/month)	Max. Network Demand Charges ($/kVA/month)
TAS	**Business (All)**	0.52	1.77	4.89	2.33	6.35	10.60	10.63	10.63	10.63	8.75	8.75	8.75
TAS	Business-	0.52	1.77	4.89	2.33	6.35	10.60	10.63	10.63	10.63	8.75	8.75	8.75
ACT	**Business (All)**	0.43	0.54	0.60	6.38	12.14	20.42	-	-	-	13.48	14.56	15.20
ACT	Business-	0.43	0.54	0.60	6.38	12.14	20.42	-	-	-	13.48	14.56	15.20
NT	**Business (All)**	1.47	24.72	71.20	1.90	4.03	8.00	10.00	13.00	16.00	-	-	-
NT	Business-Small/ Medium (< 750 MWh pa)	1.47	1.49	1.50	2.20	5.10	8.00	16.00	16.00	16.00	-	-	-
NT	Business-Large (>750 MWh pa)	71.20	71.20	71.20	1.90	1.90	1.90	10.00	10.00	10.00	-	-	-
WA	**Business (All)**	1.68	103.74	546.65	9.26	10.53	11.89	-	-	-	2.07	10.64	21.37
WA	Business-	1.68	48.38	372.02	9.26	10.53	11.89	-	-	-	2.07	11.72	21.37
WA	Business-V Large Business (> 1 MVA)*	546.65	546.65	546.65	-	-	-	-	-	-	7.20	8.48	17.16

Note: This category includes a large range of customers. Tariff prices for Ergon West are higher than the other regions. The highest supply charge is linked to the tariffs for customers with large demand in Ergon's Western region (compared with ~$200 supply charge for a medium demand tariff). The maximum energy consumption price is significantly larger than the average due to a tariff with a high-volume charge (>20c/kwh) for the second volume block (>97,000 kWh) for tariffs in the Western region (the price for the first energy volume is ~2c/kwh). Demand charges vary depending on the location serviced. Highest demand charges were observed for the Western region serviced by Ergon. *These tariffs have a high network supply charge as this charge includes the first 1000kVA of demand.

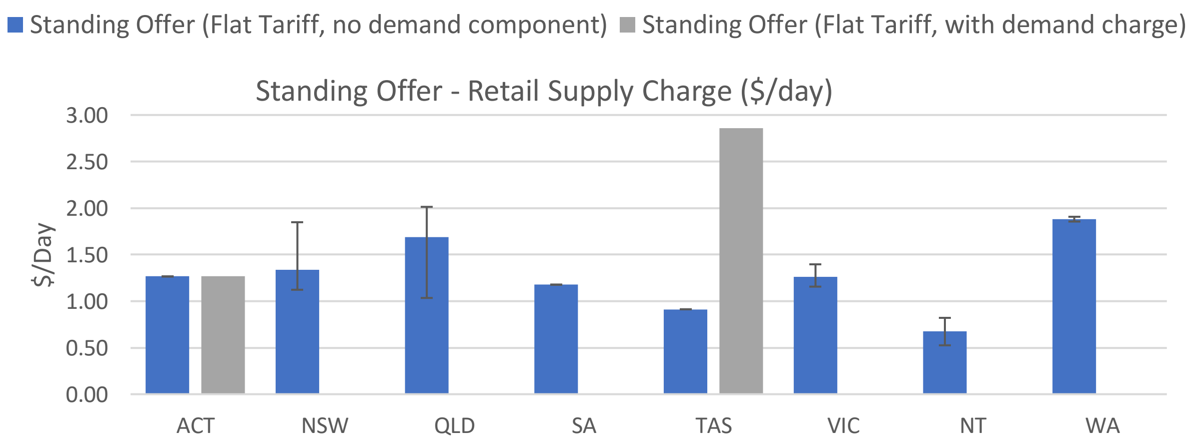
5.2.2 Retail tariffs

Generally, most commercial buildings fall into the Small Market Electricity Users pricing category. The price that electricity retailers can charge these consumers on default plans is capped in each jurisdiction in Australia and varies for each DNSP within that jurisdiction. These price caps, sometimes referred to as 'reference prices', were introduced with the intention of providing a safety net for electricity consumers. Within each jurisdiction, the authority responsible for setting the price cap, and the terminology used to refer to the price cap, differs as follows:

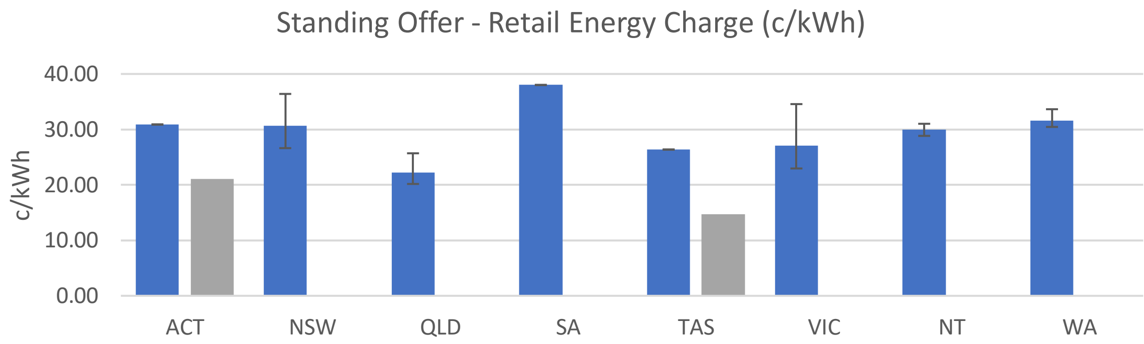
Table 31: Standing offer authorities by jurisdiction.

State	Approval Authority
ACT	Independent Competition and Regulatory Commission (ICRC)
NSW, SA and SE QLD	Australian Energy Regulator (AER)
Regional QLD	Queensland Competition Authority
TAS	Tasmanian Economic Regulator
VIC	Essential Services Commission Victoria
NT	Utilities Commission of the Northern Territory
WA	Western Australia Government as part of the State Budget process

In most states, standing offers with a flat tariff only included a fixed supply cost component and an energy consumption charge. The exception is in the ACT and Tasmania, where the standing offer tariffs incorporate a demand charge component[15]. The 2021-2022 average, minimum and maximum tariff prices for each state are presented below.



[15] Default market offer does not apply to customers with demand charges in their tariffs, and customers with no controlled loads.



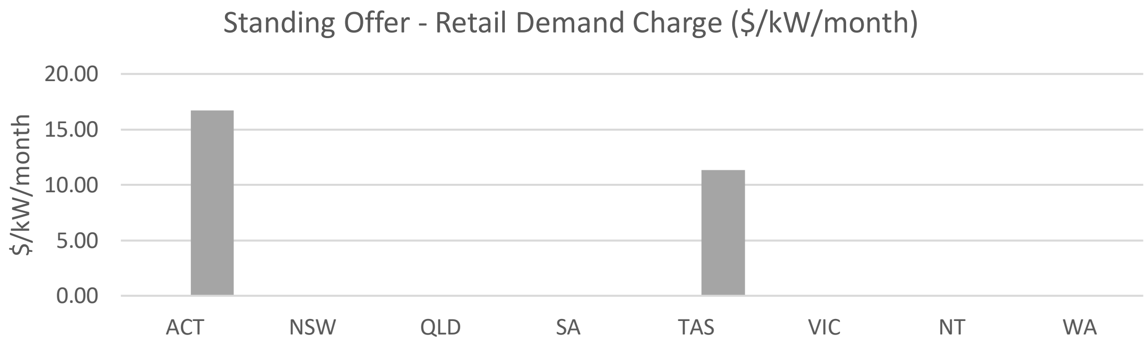


Figure 21: Standing Offer Flat Rate Tariff Prices for Small Commercial Users. (Top) Service charge in $/day, (middle) energy consumption charge in c/kWh, and (bottom) demand charge in $/kW/month. For states where there is more than one tariff, the average prices are shown, and error bars indicate the minimum and maximum price.

These show that the standing offer prices and pricing structures vary between each state and similarly to the network pricing, are functions of the underlying variation in costs borne by the retailers.

5.3 Introduction to grid demand events

5.3.1 Reliability and Reserve Energy Trader (RERT)

This is a scheme administered by AEMO to ensure reliable access and supply of electricity during predicted periods of electricity shortfall. The RERT incentivises large reserves[16] to increase generation or reduce electrical demand during these high demand periods. These events are typically both infrequent and relatively long in duration (typically 3 - 6 hours). There is also significant variation in potential revenue, with orders of magnitude variation in $/MWh unit rates and variation between states for each event. A summary of all events between Jan-19 and Jun-22 is shown in Figure 22 below.

[16] Typically, larger than 10 MW. Sites with less than 10 MW can still participate through a third party aggregator.

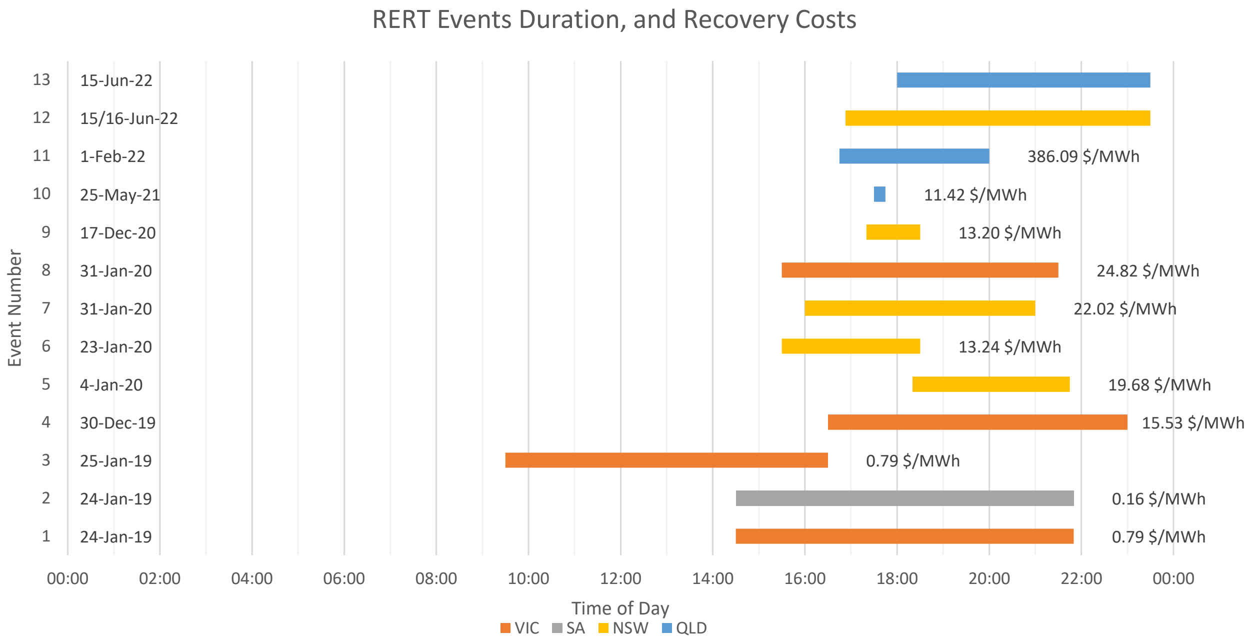


Figure 22: History of RERT events to the end of FY22.[17]

5.3.2 Wholesale Demand Response Mechanism (WDRM)

The WDRM was introduced by AEMO in Oct-21 and incentivises electricity consumers to participate in the wholesale market by receiving payment related to their load curtailment (as measured against the consumer's baseline), at the electricity spot price. While the Mechanism permits participation in the market at any time, participation at times of high electricity prices and electricity supply scarcity is most likely.

Since Oct-21, when the WDRM came into effect, to the end of FY22 there have been 16 event days of WDR with 25 registered NMIs according to AEMO's FY22 WDR Annual Report. Price in these events were typically between $500 - $2,000/MWh.

[17] https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert

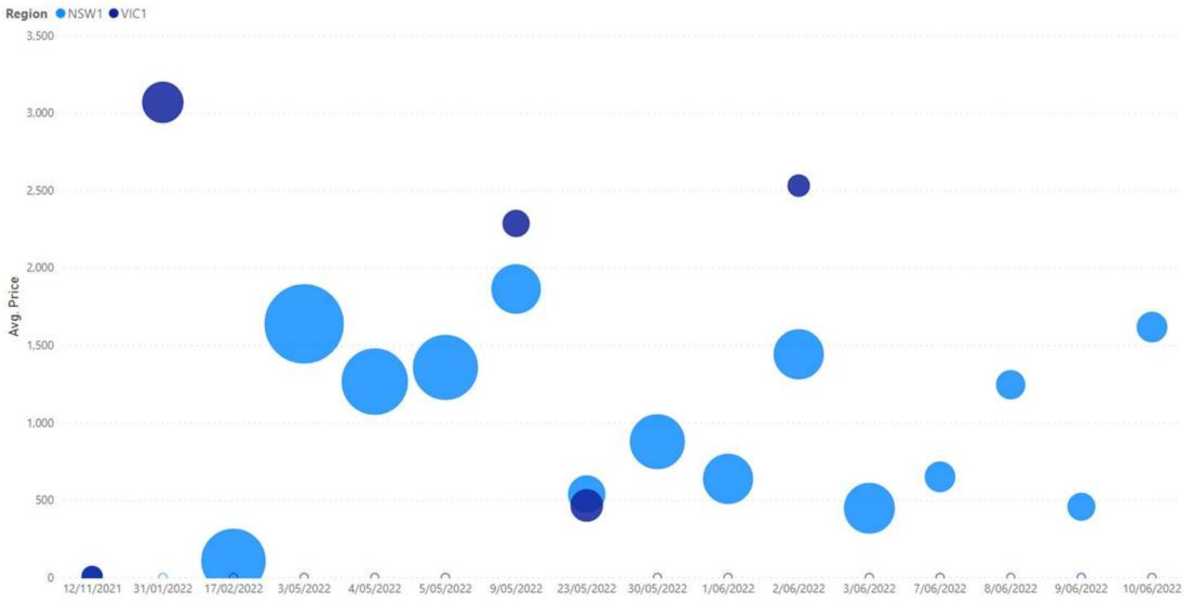


Figure 23: Average price ($/MWh). (Source: AEMO 2022 WDR Annual Report (18))

5.3.3 Frequency Control Ancillary Services (FCAS)

AEMO is responsible under the National Energy Market (NEM) for ensuring that the power grid is operated in a safe, secure, and reliable manner. One of the technical characteristics is the frequency of the grid should be maintained close to 50 Hz.

A site's potential to contribute to balancing the grid frequency generally falls into one of three categories:

1. Load shedding: where a load can be quickly disconnected from the electrical system (can act to correct a low frequency only)
2. Rapid generation: where a frequency relay will detect a low frequency and correspondingly start a fast generator (can act to correct a low frequency only)
3. Rapid unit unloading where a frequency relay will detect high frequency and correspondingly reduce a generator output (can act to correct a high frequency only).

To participate, a site is required to participate in one or more of the 8 FCAS markets:

Regulation Market

- Regulation Raise: Regulation service used to correct a minor drop in frequency.
- Regulation Lower: Regulation service used to correct a minor rise in frequency.

Contingency Market

- Fast Raise (6 Second Raise): 6 second response to arrest a major drop in frequency following a contingency event.
- Fast Lower (6 Second Lower): 6 second response to arrest a major rise in frequency following a contingency event.
- Slow Raise (60 Second Raise): 60 second response to stabilise frequency following a major drop in frequency.
- Slow Lower (60 Second Lower): 60 second response to stabilise frequency following a major rise in frequency.

- Delayed Raise (5 Minute Raise): 5-minute response to recover frequency to the normal operating band following a major drop in frequency.
- Delayed Lower (5 Minute Lower): 5-minute response to recover frequency to the normal operating band following a major rise in frequency.

FCAS prices vary between less than $2 / MW to $15-$20 / MW in recent years depending on the sub-market response.

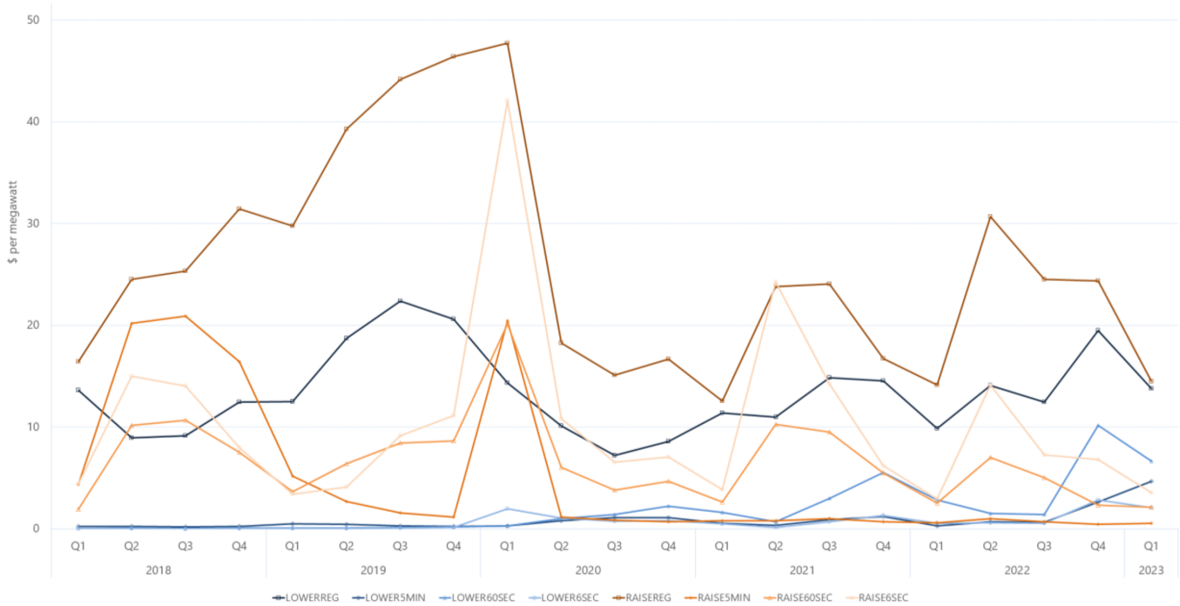


Figure 24: Average FCAS prices for the last 5 years. (Source: Australian Energy Regulator)[18]

5.4 Challenges with Incorporating Peak Demand Management in the Code

Active control of peak demand from “behind the meter” strategies have several challenges both in a site’s ability to carry out and in quantifying the benefit.

5.4.1 Quantifying the benefit

An overarching challenge is the inability to systematically quantify the potential energy and demand savings from employing any behind the meter strategy. It was shown in Table 30 for non-residential consumers that the network tariffs exhibit little consistency in demand charges, network charges and pricing structure. Some sites will not even have a demand charge priced separately from their energy charge (the demand component will be incorporated into their energy charge). Demand charges vary over a range of two orders of magnitude between lowest and highest and average demand charges can vary by up to one order of magnitude between jurisdictions.

Furthermore, tariffs are subject to significant change (typically annually) and so any benefit to cost estimate cannot be assumed to hold true in the medium term. Figure 25 shows an extract from AER’s May-23 Final Determination (accessible through the AER website), demonstrating real increases pricing of up to 22% year on year change. There is no standardised demand pricing and therefore consumers do not have equal access to demand management savings.

[18] https://www.aer.gov.au/wholesale-markets/wholesale-statistics/quarterly-global-fcas-prices-by-services

Distribution zone	Description	Residential without controlled load	Residential with controlled load	Small business without controlled load
Ausgrid	DMO price	$1,827	$2,562	$4,999
	for annual usage of	3,911 kWh	Flat rate 4,813 kWh + CL 2,005 kWh	10,027 kWh
	Change y-o-y	+$315 (20.8%)	+$440 (20.7%)	+$639 (14.7%)
	Change y-o-y (real)	+$221 (14.6%)	+$307 (14.5%)	+$367 (8.4%)
Endeavour Energy	DMO price	$2,228	$2,977	$4,598
	for annual usage of	4,913 kWh	Flat rate 5,214 kWh + CL 2,206 kWh	10,027 kWh
	Change y-o-y	+$392 (21.4%)	+$594 (24.9%)	+$816 (21.6%)
	Change y-o-y (real)	+$277 (15.1%)	+$445 (18.7%)	+$580 (15.3%)
Essential Energy	DMO price	$2,527	$2,977	$5,761
	for annual usage of	4,613 kWh	Flat rate 4,613 kWh + CL 2,005 kWh	10,027 kWh
	Change y-o-y	+$435 (20.8%)	+$487 (19.6%)	+$860 (17.5%)
	Change y-o-y (real)	+$304 (14.5%)	+$331 (13.4%)	+$554 (11.3%)
Energex	DMO price	$1,969	$2,363	$4,202
	for annual usage of	4,613 kWh	Flat rate 4,412 kWh + CL 1,905 kWh	10,027 kWh
	Change y-o-y	+$349 (21.5%)	+$402 (20.5%)	+$756 (21.9%)
	Change y-o-y (real)	+$248 (15.3%)	+$279 (14.2%)	+$541 (15.7%)
SA Power Networks	DMO price	$2,279	$2,787	$5,849
	for annual usage of	4,011 kWh	Flat rate 4,212 kWh + CL 1,805 kWh	10,027 kWh
	Change y-o-y	+$439 (23.9%)	+$512 (22.5%)	+$1,310 (28.9%)
	Change y-o-y (real)	+$324 (17.6%)	+$370 (16.3%)	+$1,026 (22.6%)

Figure 25: Extract from AER's Default market offer prices 2023-24 Final determination (6).

5.4.2 Physical limitations

The behind-the-meter demand management scenarios presented in Section 5.1.1 are considered below:

a) Permitting thermal conditions within the building to drift within tolerance levels

This method involves permitting the zone temperatures to drift during times of peak demand. In this case, allowing zone temperatures to drift upwards when AHUs are in cooling mode is considered.

The peak demand challenge here is this method of control is already considered best practice and any additional demand management involves permitting zone temperature to exceed Lease/Owner Tenant Agreement conditions. Implementation of this is typically outside the control of the Developer and Builder.

b) Using on site storage (battery/thermal chilled water)

Using on-site storage such as batteries and stored chilled water for peak demand management presents several key challenges.

As described in Section 3.4, the benchmark cost for smaller lithium-ion battery storage systems is $1,000-$1400 /kWh, with an expected service life of 10 years (or 5,000 cycles, whichever comes first). As discussed in Section 3.4.2, the cheaper costs for larger batteries installed directly on the grid mean that building-level batteries are not societally beneficial as a means of addressing the grid-based challenges addressed by RERT, WDRM and FCAS. This leaves only the management of tariff demand charges as a potential application for batteries; but as noted above, such demand charge varies widely such that no site is guaranteed of a given potential saving from such management. As a result, batteries can be discarded as a potential code-level demand response measure for buildings.

When considering using stored chilled water for behind the meter demand management, the following scenario has been considered:

- Required demand management duration: 3 hrs.
- Chiller thermal demand from stored water: 50 W/sqm
- Chilled water temperatures: 6°C supply, 11°C return (5°C temperature difference)
- System COP of 6

Only three of the building archetypes are modelled as having chilled water loops (Class 3 – Hotel, Class 5 – Large Office and Class 9 – Hospital Ward). The volume requirements to meet the requirements listed above have been estimated using:

$$Q = mc_p\Delta T$$

Where Q is stored energy, m is stored mass of chilled water, c_p is the specific heat of water and ΔT is the difference between supply and return chilled water temperature.

Table 32 lists the indicative volumetric storage requirements under these conditions which are exorbitant and prohibitive - especially when considering this thermal model has not taken standing losses into account.

Table 32: Estimated chilled water storage for relevant archetypes.

	Class 3 Hotel (C3HL)	Class 5 Large Office (C5OL)	Class 9 Hospital Ward (C9A)
Conditioned area (m^2)	7,040	11,040	5,710
Thermal demand (kW_{th})	352	552	286
Electrical demand (kW_e)	59	92	48
Mass of water (kg)	181,838	285,155	147,485
Volume of water (m^3)	182	285	147

If assuming a system coefficient of performance (COP) of 6, the estimated electrical demand saving for each archetype does not exceed 100 kW. This is further discussed in Section 5.5, where the possible revenue stream from peak demand market participation is considered.

Finally, since only three archetypes have chilled water systems, behind the meter demand management through stored chilled water is only available to a subset of buildings.

Using on site generation with synchronisation equipment

The grid synchronisation of any on-site generation (rotating machines in particular) requires cooperation and often technical consultation with the network provider. As an example, for synchronisation of rotating machines above 30kVA on Ausgrid's network requires the following stages of consultation and approval[19]:

- Conceptual approval by Ausgrid
- Design approval by Ausgrid
- Ausgrid approval of proposed test plan

[19] Ausgrid Network Standard Embedded Generation, Section 8.4

- Arrangement for Ausgrid representative for specific testing

These requirements are a significant barrier to entry for this demand management practice when applied through a national code.

5.5 Challenges with Incorporating Market Participation in the Code

There are several specific challenges with incorporating grid event participation in the Code. One of the key challenges is the inability to quantify the benefit. With the:

- Range of market types
- Variation in market pricing between events and states
- Inability to reliably predict the number of expected events and
- Variation in the number of events in each state/network

The benefit of grid event participation cannot be determined. Other challenges are outlined below.

5.5.1 Reliance on market aggregators

For smaller participants – which basically means all buildings - participation in any market will likely only be achievable through a market aggregator. For example, Shell Energy's Demand Response programs[20] only permit participation to businesses meeting the following thresholds:

- Based in VIC, SA, QLD, or NSW
- Use over 3 GWHS per annum.
- Can reduce a minimum of 500 kW via load reduction, back up generation, storage, or chiller plants.
- Can reduce electricity when requested.
- Capable of reliable participation with minimal or no disruption to everyday operation.

Market aggregators charge a commission/fee which further erodes the revenue potential for the small market participant.

When considering the stored chilled water scenario modelled in Section 5.4, it was estimated a maximum of 94 kW electrical peak demand reduction behind the meter for the Class 5 Large Office archetype. Since the typical time frame for RERT event participation is 3 – 6 hours, no archetype will be able to directly participate in the RERT market and will be forced to rely on an Aggregator to participate.

Furthermore, with no RERT events in NT, TAS and WA, there is unequal opportunity for market participation, even if relying on aggregators to participate.

5.5.2 Participation in WDR market

When considering the potential to participate in the WDR market with stored battery or thermal energy, it is clear there is limited potential as the market depth is very low – with only 16 event days between Oct-21 and Jun-22, no events in QLD and only 5 events in VIC a business case cannot reliably be established.

[20] https://shellenergy.com.au/energy-solutions/demand-response/

5.5.3 HVAC provision of FCAS

The major issue for HVAC provision of FCAS is the ability of the system to respond within the timeframes required. BMS systems have effective refresh rates in the region of 2-15s, making them suitable only for the deployment of delayed raise/lower services. Faster services require dedicated controllers that override BMS commands on a short-term basis; for fast raise services it is possible that some equipment-level controllers may struggle to respond in a timely manner.

The requirements for the frequency of metering (0.25-20Hz, corresponding to measurement intervals of 50ms-4s) under FCAS exceed the capability of most conventional metering used in buildings, although some systems are capable of measurement down to a 1s interval. Measurement on a 50ms basis requires specialist equipment. Based on the above, the theoretical potential control and metering configurations for HVAC provision of FCAS are as follows:

- Fast raise/lower: specialist metering, with control via faster time-base conventional controllers (such as VSDs) or specialist equipment at plant item level.
- Slow raise/lower: high performance conventional metering, with control via faster time-base controllers at plant item level.
- Delayed raise/lower: high performance conventional metering, with control via controllers at plant level or via BMS.

However, participation in these slower response FCAS markets have only generated less than $10/MW since 2019 (approx. 10% of the RIS economist peak demand charge).

5.5.4 Risk of future power plants

There is approximately 7,900 MW of new generation in the NEM forecast to commence operation in the next 10 years[21], which represents approx. 12% of the current generation capacity. There are also projects such as the Waratah Super Battery Project[22], a 350MW (4 hour) large scale battery in Gippsland[23] and Snowy 2.0 all of which facilitate some degree of peak demand management capability. The effect of the new, flexible generation on the current demand and grid event revenue stream is difficult to quantify.

5.5.5 Technical challenges

Recalling the current range of grid demand events described in Section 5.3, there is no single technological or communication equipment which permits participation in all markets. Each grid event type has a different mechanism of notifying the potential participants (and indeed in some cases such as the faster response FCAS submarkets with 6 second responses, no prior notice will be given). Therefore, for a new development to have the capability of market participation, the actual market(s) would have to be determined during design. Considering this along with the geographical diversity in demand markets, a standardised approach cannot realistically be applied.

[21] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

[22] https://www.energyco.nsw.gov.au/projects/waratah-super-battery

[23] https://www.energyaustralia.com.au/about-us/what-we-do/new-energy-projects/wooreen-energy-storage-system

5.5.6 Risk of diminishing returns

While a business case for grid event participation cannot be established and the potential revenue streams are highly variable, the future potential revenue streams will still fundamentally be at risk of diminishing returns as market participation in the provision of demand response grows. In this environment, small market participants are likely to be outcompeted by large, grid level generators and storage systems. Conversely, were the market to be flooded by code-driven requirements for demand response capability and participation, this could also significantly change the economics of the market given its limited depth at the time of writing.

5.6 Conclusion

NCC Section J is not an appropriate tool to standardise peak demand management practices or grid event market participation.

The demand response market is complex and immature. There is little market depth, few direct participants and for most consumers to participate, they would have to participate indirectly through aggregators. Revenue from demand response is limited, uncertain, and not geographically uniform. The market processes are not sufficiently developed or sufficiently streamlined to accommodate the broader consumer market.

For behind-the-meter demand management, use of stored chilled water or batteries incurs significant costs but must be set against network tariffs that differ widely in their treatment and charging of peak demand.

On the basis of the lack of uniform price signals – as well as other implementation difficulties – it is clear that a Code-level provision for inclusion of peak demand management capacity cannot be economically justified. As a result, no measure is proposed.

Appendix A: PV/Battery Analysis

Equipment – Rooftop PV

PV System Overview

Solar PV systems are power systems that convert sunlight into electricity by utilizing the photovoltaic effect. This is a process in which semiconducting materials generate voltage and current when exposed to light. For real world applications, this effect is usually implemented with the aid of solar cells which are individual devices whose electrical characteristics vary when exposed to light. These cells are usually made out of polycrystalline or monocrystalline silicon and can be connected in series or parallel to achieve the desired voltage and current respectively. A number of solar cells packed into a metal frame is called a solar module or solar panel and this is the form in which solar PVs are commercially made available for use.

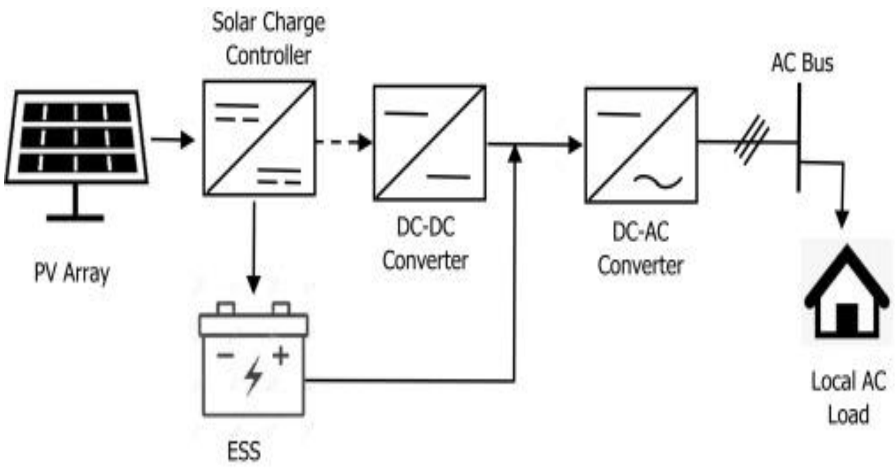


Figure 1: Solar PV system connected to load.[24]

Solar Panel Types

There are three types of solar panels primarily available today: **monocrystalline**, **polycrystalline** (also known as multi-crystalline), and **thin film**. These solar panels vary in appearance, performance, costs, and how they're made. Depending on the type of photovoltaic (PV) installation you're considering, one option may be more suitable than the others.

[24] M.F. Akorede, *Design and performance analysis of off-grid hybrid renewable energy systems*, Academic Press, 2022.

Table 33: Solar PV types, advantages, and disadvantages

Solar Cell Type	Efficiency Rate	Advantages	Disadvantages	Photo
Monocrystalline Solar Panels (Mono-SI)	~20%	High efficiency rate; optimised for commercial use; high life-time value	Expensive	
Polycrystalline Solar Panels (p-Si)	~15%	Lower price	Sensitive to high temperatures; lower lifespan & slightly less space efficiency	
Thin-Film: Amorphous Silicon Solar Panels (A-SI)	~7-10%	Relatively low costs; easy to produce & flexible	shorter warranties & lifespan	
Concentrated PV Cell (CVP), (commercial application only)	~41%	Very high performance & efficiency rate	Solar tracker & cooling system needed (to reach high efficiency rate)	

Conventional Solar Panel

A conventional solar panel typically contains sixty 0.5V solar cells wired up in series. Voltages add in series, so this example solar panel operates at 30V.

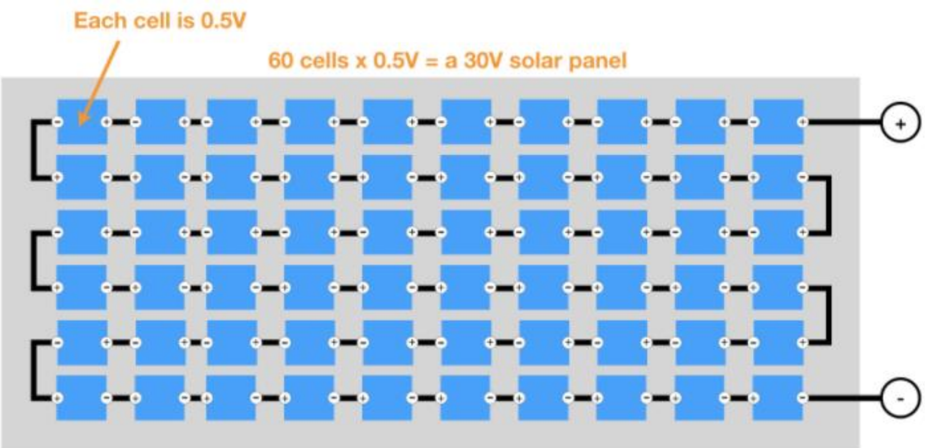


Figure 26: Conventional Solar PV Panel[25]

A standard solar panel has 3 strings. Thanks to bypass diodes (shown in red below), one small spot of shade on a panel, caused by, say, a leaf or bird droppings, will impact an entire cell string, but not affect the others. This is illustrated by the following figure.

[25] Solar Quotes, 2018, Solar Quotes Website, accessed 20 May 2023, https://www.solarquotes.com.au/blog/half-cut-solar-cells-panels/

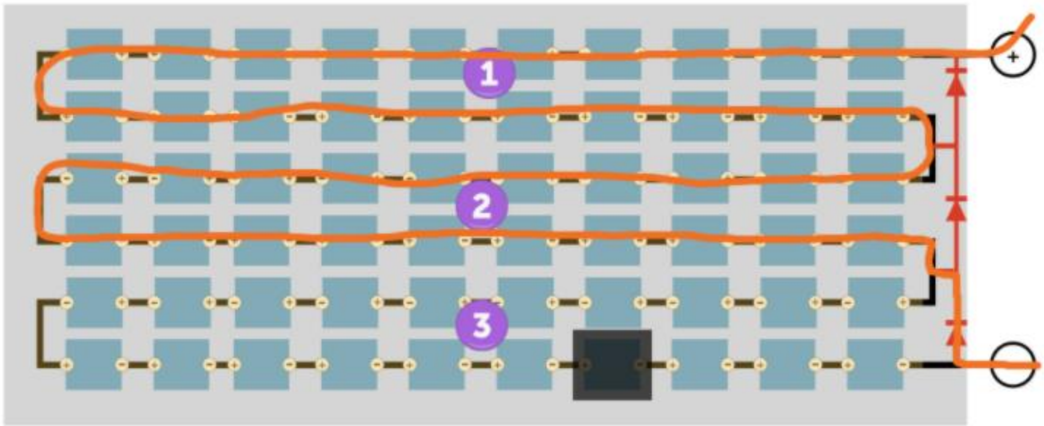


Figure 27: Conventional Solar PV Panel Shading Response[26]

Two-thirds of the cells are active, so the result is approximately two-thirds of the power.

Half Cell Technology of Solar Panels

Half-cut solar cells are normal solar cells that have been cut in half. Instead of having 60 solar cells, as most panels put on roofs do, they have 120 half-sized ones. This results in lower electrical resistance that improves efficiency. An additional benefit is half cut panels resist the effects of shade better than standard solar panels. This isn't directly due to the cells being cut in half but because of the way they are wired together. While the increase in efficiency is only small, several large manufacturers are convinced modern production techniques make half-cut solar cell panels worthwhile, (for example, Trina, Longi Solar, Jinko Solar etc).

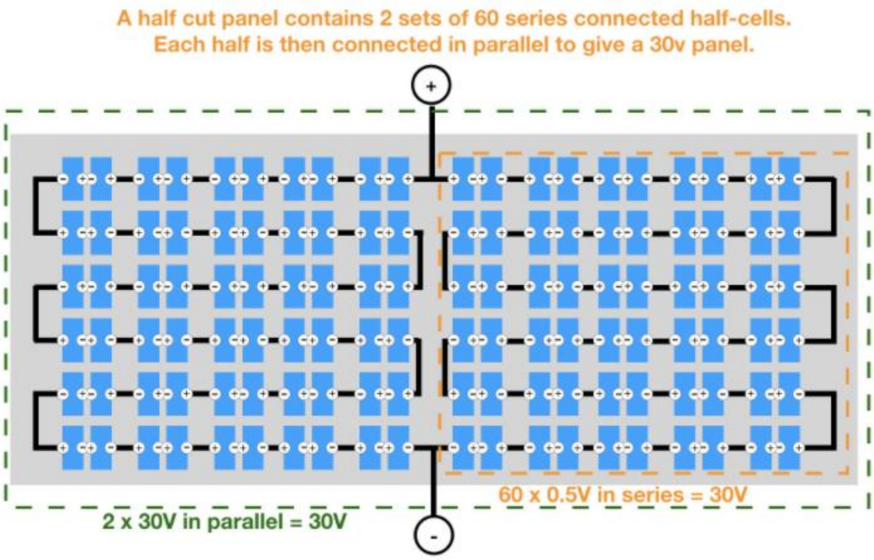


Figure 28: Half Cut Solar PV Panel[27]

[26] Solar Quotes, 2018, Solar Quotes Website, accessed 20 May 2023, https://www.solarquotes.com.au/blog/half-cut-solar-cells-panels/
[27] Solar Quotes, 2018, Solar Quotes Website, accessed 20 May 2023, https://www.solarquotes.com.au/blog/half-cut-solar-cells-panels/

Instead of having 3 cell-strings like a standard solar panel, the half-cut panel has 6 cell strings making it a 6 string panel. One small spot of shade on a half-cut panel yields the following example. The current can go as per orange path, only five-sixths of the cells are active.

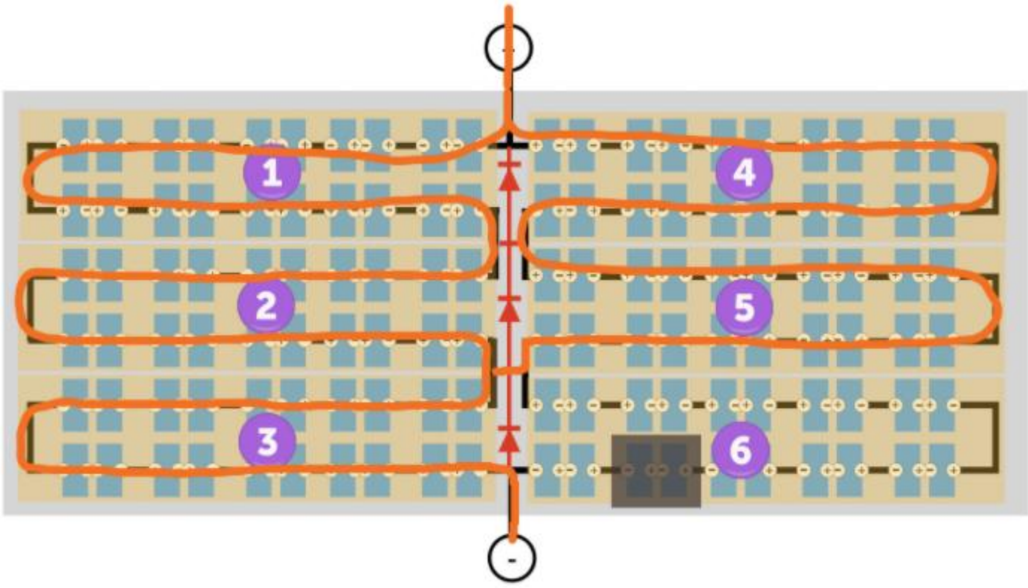


Figure 29: Half Cut Solar PV Panel Shading Response

Flat or Angled Solar Panel

Solar Panel can be installed either flat or angled in the roof, however, flat installing will experience a degree of energy loss as the sun will not be directly perpendicular above the solar panels for typical 6 to 12 hours. To fully harness the sun's power, the solar panels must be installed at the best angle, facing the sun and soaking in as much sunlight as possible. This is because the photovoltaic cells or PV cells are hypersensitive but still need full access for maximum performance.

Also, Solar panels should not be flat because they can collect water which will build up on the surface and damage the solar cells. So, it is much better to angle them; not too much – as little as three to four degrees tilt will ensure that rainwater continually glides off the surface.

- **Flat Roof Disadvantages**:
    - Efficiency:

      The optimum angle for generating electricity is when the panel is perpendicular to the sun. Generally, this angle equals the latitude at the location of installation. These optimum angles are listed below for each capital city. The two following graphs are the annual yield of a 10kW system located in Sydney at 0 and 33 degrees respectively.

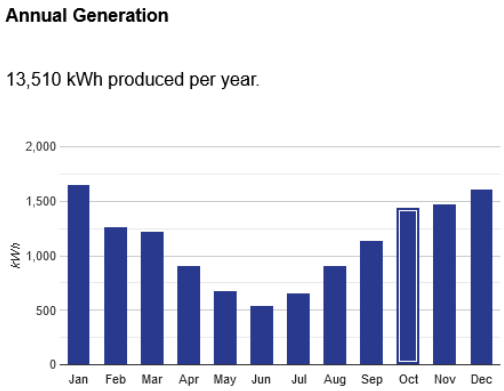


Figure 30 - Flat-panel installation @ 10kW North Facing (Sydney)

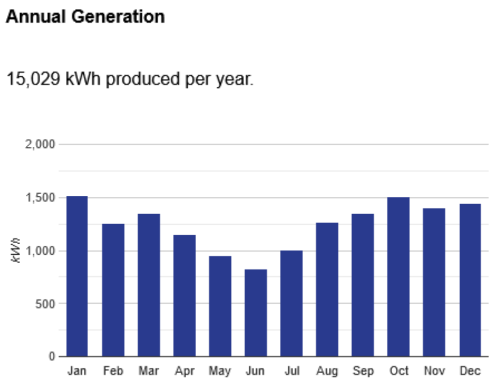


Figure 31 - Optimum angle tilt installation @ 10kW North Facing (Sydney)

As evidenced by the example installations, the decrease is approximately 11% under these circumstances.

- Self-Cleaning:

  Flat (i.e. no tilt) solar panel mounting allows debris and dust to collect on the surface of the panel, reducing its efficiency and power generation. When tilted, rainwater will clear the surface of the panel resulting in minimal active maintenance. Mounting panels on a flat bracket (or flat roof) requires increased spacing between units so that each be access for maintenance and cleaning.
  Soiling of panels results in a drop in efficiency by approximately 50% with variables such as type of debris, density and extent of coverage impacting the reduction. The impact of debris can be considered equivalent to the impact of shading as noted above.

Best position of Solar panel

The best position for solar panels is an angle tilted toward or perpendicular to the sunlight. Installing the solar panels at the ideal tilt angle and orientation for the latitude ensures that the system generates as much electricity as possible for the proposed location. The ideal orientation for a solar panel array is due north, and the ideal tilt angle is the angle of your latitude (e.g. about 30 degrees in Sydney and Perth). Small variations away from these ideals will not result in a significant difference in the power output of your solar energy system, the natural slope of roof structures for drainage purposes is sufficient for panel tilt as well.

The actual optimum angle changes from state to state. This is because the ideal angle is always equal to the latitude angle of the location.

As a rough guide, the optimal angles (from horizontal) for solar panels are listed below for Australia's capital cities.

- Sydney – 33.9 degrees
- Brisbane – 27.5 degrees
- Melbourne – 37.8 degrees
- Hobart – 42.9 degrees
- Perth – 31.9 degrees
- Darwin – 12.5 degrees
- Adelaide – 34.9 degrees

PV System Cost Estimation

Cost of any PV system relies on roof size, roof material, PV system capacities/sizes, system components in terms of solar panel brands, inverter manufacture, using microinverter/optimisers, etc.

The cost estimate doesn't change based on the class of buildings. It has a direct relationship to the following factors:

- Flat roof: Solar panels should be optimally angled toward the sun. In a flat roof, there is additional cost for installing solar panel brackets which keeps the solar panels in correct tilt towards the sun. The additional installation cost is around $80 to $120 per panel.
- Roof condition: Nearly all types of rooves can have solar panels attached, however the harder your roof is to work on, the more installers will charge. Old rooves which require more delicate work will be the most expensive.
- Installer demand: Installation costs are largely dependent on supply and demand. In areas, or at times, where installers have a lot of work to get through, they will tend to charge a higher price. Generally speaking, solar technicians are in lower demand (and therefore cheaper) in the early parts of autumn and spring.
- Solar panel quality: Not all solar panels are the same. Based on a budget or premium brands/manufacture, some panels are more efficient at transforming sunlight into useable electricity. The more that panels are efficient, the more they are expensive. Efficient panels are more expensive in the short term but may save you more in the long term.

PV System – Microinverters/optimisers

- Microinverters: A micro inverter is an inverter that is installed on solar panels to convert the direct current energy (DC) generated by the panels into alternating current (AC) electricity for use in the home. They are about the size of an internet router and one is installed underneath each solar panel. The main advantage of a micro inverter solar system is that it can measure the generation of each panel independently as opposed to managing all panels at once.
- Micro inverters vs String inverters: The key difference between micro inverters and string inverters is that micro inverters are installed on each individual panel, whereas string inverters use just one system for all panels – typically installed away from the panels either outdoors or indoors (depending on the model).
  Theoretically, micro inverters should yield more solar power. This is because when solar panels operate in a 'string' with string inverters, the current is reduced to that of the lowest-

producing panel in the system. Micro inverters, on the other hand, produce energy independently of their neighbouring solar panels. This makes micro inverter solar systems the more attractive option when it comes to combatting shaded areas or the impacts of low light. This is because only the covered panels' generation is compromised, as opposed to the entire system's performance. Micro inverters also tend to operate at a lower voltage than string inverters.

Figure 32: Microinverter[28]

Solar Quotes, 2018, Solar Quotes Website, accessed 20 May 2023, https://www.solarquotes.com.au/blog/half-cut-solar-cells-panels/

- Microinverter Cost: Micro inverters tend to be more expensive than string inverters to install, costing between $4,000 and $11,500 on average for an installation. This is because there is more wiring and equipment involved with micro inverters as there is one system per panel – or in some cases one system per every two to four panels. With a string inverter, only one system needs to be purchased and wired for all panels.
- Benefits of Microinverter: Micro inverters come with a hefty price tag, so it is important to consider whether the benefits are worth it. Below are some of the key advantages of using a micro inverter solar system:

[28] Solar Quotes, Solar Quotes Website, accessed 20 May 2023, https://www.solarquotes.com.au/inverters/micro/

  - Allows for a more flexible panel layout and expansion.
  - Allows for panel-level monitoring and optimization.
  - No single point of failure, meaning that if one panel doesn't work then it doesn't stop the rest of the panels from performing and providing the household with power.
  - Generally, come with longer warranty periods than string inverters – usually 25 years as opposed to eight(8) to twelve(12) years.
- Drawbacks of Microinverter System: While there are some benefits to installing a micro inverter, like anything, there are also a few things to be cautious of – namely the upfront cost and maintenance. Being on the roof directly instead of on the side of the house means that micro inverter systems run a slightly higher risk of weather damage. As such, it is important to ensure that these systems are installed properly and with the utmost care. Keeping the system regularly maintained will also be crucial, to ensure all parts are still running at maximum capacity.
  - It is more expensive; the higher upfront costs are also something that will need to be considered. Being that multiple systems need to be purchased to fit out an entire solar panel system, the cost of installing micro inverters often ends up being much larger than that of a regular string inverter.
  - Least suited for battery backup systems, Microinverters are not the best option for adding battery storage to your solar system. For optimal power production, connect your panels to your battery before converting the current to AC and then back to DC.
  - An Upgrade is Required: Although microinverter manufacturers claim to offer a monitoring system, they do not always include it in their package unless you purchase an upgrade.
- Optimisers: Optimisers are the same concept of Microinverters, they are connected to the solar system to increase the generating output power. A solar panel optimiser is a device that can be added to one or all panels in a string. The optimiser's main objective is to increase the overall output of the solar installation by bypassing the panel that is not working at total capacity. This allows the solar system to operate to its full potential regardless of a shaded panel, therefore resulting in the best energy production for you and your home.
- The difference between Microinverters and optimisers is they still send the power down to a central inverter to convert power from DC to AC. Still, they essentially break your system into independent pieces like micro inverters do, protecting your system from partial shading. These turn your DC solar panels into AC solar panels to use directly.
- String Inverters Vs Microinverters inverters Vs Optimizers: As mentioned above, central inverters operate as a string or circuit, and if just one panel is shaded, they can be disconnected. Micro inverters allow each panel in the system to operate independently. A microinverter costs $1.15 per watt, compared to $0.75 per watt for central inverters. You may alternatively use a power optimizer instead of a micro-inverter, which costs around $1.00 per Watt and achieves the same thing.

Table 34: Inverter and optimiser costs

	String Inverter	Micro Inverter	Power Optimizer
Cost per Watt	$ 0.75	$ 1.15	$ 1.00

Equipment – Grid-scale PV

The Tables Table 35 – Table 40 includes the details of the various components considered for the grid scale PV system:

PV Panel

Table 35. Technical Specifications for the PV Panels for Grid PV

Specification	Description
Type	Bifacial Dual Glass Monocrystalline Module
Power Range	640 - 665 W
Power Tolerance-P_{MAX} (W)	0 ~+5W
Maximum Power Voltage-V_{MPP} (V)	37.3 - 38.3
Maximum Power Current-I_{MPP} (A)	17.19 - 17.39
Open Circuit Voltage-V_{OC} (V)	45.1 - 46.1
Short Circuit Current-I_{SC} (A)	18.26 - 18.50
Module Efficiency ηm (%)	20.6 - 21.4

String Inverter

Table 36. Technical Specifications for the String Inverter for Grid PV

Specification	Description
Input (DC)	
Max. PV array power (Wp STC)	165000
Max. input voltage (V)	1100
MPP voltage range (V)	500 - 800
Rated input voltage (V)	585
Min. input voltage / Start input voltage (V)	200 / 250
Max. input current per MPP tracker / Max. short-circuit current per MPP tracker	26 A / 40 A
Number of independent MPP trackers / Strings per MPP tracker	12 / 2
Output (AC)	
Rated power at nominal voltage (W)	110000
Max. apparent AC power (VA)	110000
Nominal AC voltage (V)	400
AC voltage range (V)	320 - 460
AC grid frequency / range (Hz)	50 / 45 to 55 60 / 55 to 65
Rated grid frequency (Hz)	50
Max. output current (A)	159
Power factor at rated power / displacement power factor adjustable	1 / 0.8 overexcited to 0.8 underexcited
Harmonic (THD) (%)	< 3
Feed-in phases / AC connection	3 / 3-PE
Efficiency	
Max. efficiency (%)	98.60

MV Power Station

Table 37. Technical Specifications for the MVPS for Grid PV

Specification	Description
Input (DC)	
Max. input voltage (V)	1500
Number of DC inputs	dependent on the selected inverters
Available DC fuse sizes (A per input)	200, 250, 315, 350, 400, 450, 500
Output (AC) on the medium-voltage side	
Rated power at SC UP (at -25°C to + 35°C / 40°C optional 50°C) (kVA)	2667 to 3067 / 2400 to 2760 kVA
Charging power at SCS UP-XT (at -25°C to + 25°C / 40°C optional 50°C) (kVA)	2390 to 22750 / 2000 to 2300
Discharging power at SCS UP-XT (at -25°C to + 25°C / 40°C optional 50°C))kVA)	2665 to 3065/ 2270 to 2605
Typical nominal AC voltages (kV)	10 to 35
AC power frequency (Hz)	50 / 60
Transformer cooling methods	KNAN (Oil Natural Air Natural)
Max. total harmonic distortion (%)	< 3
Power factor at rated power / displacement power factor adjustable	1 / 0.8 overexcited to 0.8 underexcited
Inverter efficiency	
Max. efficiency / CEC weighted efficiency (%)	98.7/ 98.5
Protective devices	
Input-side disconnection point	DC load-break switch
Output-side disconnection point	Medium-voltage vacuum circuit breaker
DC overvoltage protection	Surge arrester type I
Galvanic isolation	Yes

Central Inverter

Table 38. Technical Specifications for the Central Inverter for Grid PV

Specification	Description
DC side	
MPP voltage range V_{DC} (at 25 °C / at 50 °C)	880 to 1325 V / 1100 V to 1003 to 1325 V / 1040 V
Min. DC voltage $V_{DC, min}$ / Start voltage $V_{DC, Start}$	849 V / 1030 V
Max. DC voltage $V_{DC, max}$	1500 V
Max. DC current $I_{DC, max}$	4750 A
Max. short-circuit current $I_{DC, SC}$	8400 A
Number of DC inputs	Busbar with 26 connections per terminal, 24 double pole fused (32 single pole fused)
Number of DC inputs with optional DC coupled storage	18 double pole fused (36 single pole fused) for PV and 6 double pole fused for batteries
Max. number of DC cables per DC input (for each polarity)	2 x 800 kcmil, 2 x 400 mm²
Available PV fuse sizes (per input)	200 A, 250 A, 315 A, 350 A, 400 A, 450 A, 500 A
Available battery fuse size (per input)	750 A
AC side	
Nominal AC power at cos ϕ =1 (at 35°C / at 50°C)	4000 to 4600 kVA / 3600 to 4140 kVA
Nominal AC active power at cos ϕ =0.8 (at 35°C / at 50°C)	3200 to 3680 kW / 2880 to 3312 kW
Nominal AC current IAC, nom (at 35°C / at 50°C)	3850 A / 3465 A
Max. total harmonic distortion	< 3% at nominal power
Nominal AC voltage / nominal AC voltage range	600 V / 480 V to 720 V to 690 V / 552 V to 759 V
AC power frequency / range	50 Hz / 47 Hz to 53 Hz 60 Hz / 57 Hz to 63 Hz
Min. short-circuit ratio at the AC terminals	> 2
Power factor at rated power / displacement power factor adjustable	1 / 0.8 overexcited to 0.8 underexcited
Efficiency	
Max. efficiency / CEC efficiency	98.8% / 98.5%

Mounting System

Table 39. Technical data for the mounting system for Grid PV

Specification	Description
Type	Double-Post Steel System
Material	• Ram foundation: Steel, continuously hot-dip refined • Girder/purlins: Steel, coated with zinc magnesium alloy, • Fixing elements, screws: Zinc-flake coated steel, aluminium alternatively continuously hot-dip refined • Module clamps: Aluminium
Design	• Adjustment option for fine adjustment to the ram result • Reduced overall construction costs on the basis of static optimisation • Components for quick and easy installation
Module clamps	• Framed and unframed modules • Combined module clamping possible • Rapid16 and Rapid16L
Accessories	Cable ties
Logistics	• Maximum degree of prefabrication • Optimal transfer to the construction site
Delivery and service	• Individual frame structural analysis based on regional data • Delivery of all installation materials
Structural analysis	• Individual site structural analysis based on an external soil survey • Individual system structural analysis based on the regional critical loads Load assumptions according to DIN EN 1990 (Eurocode 0), DIN EN 1991 (Eurocode 1), DIN EN 1993 (Eurocode 3), DIN EN 1999 (Eurocode 9) and additional or corresponding country-specific standards • Profile geometries with highly efficient material utilisation • Verification of all construction components on the basis of FEM calculations • Optional: Vibration simulations for wind forces
Ground maintenance	Sheep grazing

Power Conversion System

Table 40. Technical Specifications for the Power Conversion System for Grid PV

Specification	Description
DC side	
Max. DC voltage	1500 V
Min. DC voltage	1150 V
DC voltage range	1150 – 1500 V
Max. DC current	1952 A * 2
No. of DC inputs	2
AC side (Grid)	
AC output power	4000 kVA @ 45 °C / 4400 kVA @ 30 °C
Converter port max. AC output current	2886 A @ 45 °C / 3174 A @ 30 °C
Converter port nominal AC voltage	800 V
Converter port AC voltage range	704 – 880 V
Nominal grid frequency / Grid frequency range	50 Hz / 45 – 55 Hz, 60 Hz / 55 – 65 Hz
Harmonic (THD)	< 3 % (at nominal power)
Power factor at nominal power / Adjustable power factor	>0.99 / 1 leading – 1 lagging
Adjustable reactive power range	-100 % – 100 %
Feed-in phases / AC connection	3-Mar
AC side (Off-Grid)	
Converter port nominal AC voltage	800 V
Converter port AC voltage range	704 – 880 V
AC voltage Distortion	< 3 % (Linear load)
DC voltage component	< 0.5 % Un (Linear balance load)
Unbalance load Capacity	100%
Nominal Voltage frequency / Voltage frequency range	50 Hz / 45 – 55 Hz, 60 Hz / 55 – 65 Hz
Efficiency	
Max. efficiency	99%

Equipment – Behind the Meter Battery

Battery Storage Systems – Battery Chemistry types

These are the main types of batteries used in battery energy storage systems:

- Lithium-ion (Li-ion) batteries: The most common type of battery used in energy storage systems is lithium-ion batteries. In fact, lithium-ion batteries make up 90% of the global grid battery storage market. Lithium-ion batteries are used in cell phones and laptops. A lithium-ion battery is lightweight and will likely be more expensive than some of the other options available.
- Lead-acid batteries: Lead-acid batteries are the most widely used rechargeable battery technology in the world and have been used in energy storage systems for decades. Lead-acid batteries may be familiar since they are the most popular battery for internal combustion vehicles. They have a shorter lifespan than other battery options but are the least expensive.
- Redox flow batteries: Redox flow batteries have chemical and oxidation reactions that help store energy in liquid electrolyte solutions which flow through a battery of electrochemical cells during charge and discharge. Redox flow batteries minimize environmental risk and improve response time to demand. Instead of the typical battery where the electrolyte system is encapsulated between electrodes and limited to the volume of the secondary battery, the electrolytes in a redox flow battery are circulated from a reservoir tank. Redox flow systems require increased space and are less portable due to this requirement. The charge and discharge of flow batteries requires an increase in surface area for any connections, paired with the relative immaturity of the technology result in this solution being less commercially available in the market. Redox-flow are positioned at a grid-level installation rather than customer-level.
- Sodium-sulphur batteries: Sodium-sulphur batteries are made up of molten sulphur and molten sodium, the sulphur is positive, while the sodium is negative. Sodium-based batteries are more sustainable than lithium-ion batteries since there is an abundant amount of sodium in the earth’s crust. However, Sodium-sulphur batteries must be kept hot, 572 to 662 degrees Fahrenheit, in order to operate, which can obviously be an issue for operation, especially at a place of business. The round-trip efficiency is high – in the 90% range.
- Zinc-bromine flow batteries: The zinc-bromine battery is a hybrid redox flow battery. The Energy Storage Association says most of the energy in these batteries is stored by plating zinc metal as a solid onto anode plates in the electrochemical stack during charge.

Comparatively, Li-ion is the most common and economical type due to high energy density, fast charging time and being low toxicity. Refer to the following table for a comparison of typical types.

Table 41: Battery chemistry comparison

Specs	Lead Acid	NiCd (nickel-cadmium)	NiMH (nickel-metal hydride)	Li-Ion - Cobalt	Li-Ion - Manganese	Li-Ion - Phosphate	Redox Flow
Specific Energy Density (Wh/kg)	30-50	45-80	60-120	150-190	100-135	90-120	10-20
Life Cycle (80% discharge)	200-300	1000	300-500	500-1,000	500-1,000	1,000-2,000	15,000 - 20,000
Fast-Charge Time	8-16h	1h typical	2-4h	2-4h	1h or less	1h or less	10-12h
Overcharge Tolerance	High	Moderate	Low	Low. Cannot tolerate trickle charge	Low. Cannot tolerate trickle charge	Low. Cannot tolerate trickle charge	Moderate
Self-Discharge/month (room temp)	5%	20%	30%	<10%	<10%	<10%	<2%
Cell Voltage (nominal)	2V	1.2V	1.2V	3.6V	3.8V	3.3V	1.15-1.55
Charge Temperature	-20 to 50°C -4 to 122°F	0 to 45°C 32 to 113°F	0 to 45°C 32 to 113°F	0 to 45°C 32 to 113°F	0 to 45°C 32 to 113°F	0 to 45°C 32 to 113°F	-40 to 80°C
Maintenance Requirement	3-6 Months (topping charge)	30-60 days (discharge)	60-90 days (discharge)	Not required	Not required	Not required	Not required

Pricing

For smaller battery storage systems less than 108kWh, a typical system at this scale would have batteries as shown in the Table 42. It is to be noted that, All above cost values are supply and install cost, installation cost will depend on the site condition, amount of AC cables required, cabling path and other provisions towards terminations including current switchboard space (if it is brownfield) protection relays and breakers.

Table 42. The range of systems available in the average sizes and its cost

Manufacturer	M1	M2	M3	M4
Capacity (kWh)	13.5	10	9	9
Cost per kWh	$1,222	$1,400	$1,555	$1,588

Equipment – Grid-scale Battery

For grid-scale battery, Table 43 to Table 45 includes the technical specifications of typical batteries of different size range.

Battery Size Range 1

Table 43. Battery module for batteries of ~108kWh capacity

Basic Parameters	Description – Model 1	Description – Model 2
Type	736V148Ah	729.6V148Ah
Battery System Capacity (kWh)	108.93	107.98
Battery System Voltage(Vdc)	736	729.6
System Voltage Range(Vdc)	621-828	615.6-820.8
Efficiency	96%	96%
Depth of Discharge	90%	90%
Dimension (W*D*H, mm)	815*659*2130	803*855*2130
Weight (Kg)	1,250	1,228
Design Life	15+ Years	15+ Years
Operation Temperature (C)	10 - 40	10 - 40
Humidity	5%-95%	5%-95%
Altitude	<2000	<2000
Battery Module Qty (Optional)	1-23 pcs	1-19 pcs
Authentication Level	UL1973/IEC62619/VDE/CE	IEC62619/CE

Battery Size Range 2

Table 44. Battery module for battery of ~500kWh.

Specification	Description
Battery cabinet data	
Cell type	LFP
Battery capacity (BOL) at DC side	537 kWh
Battery capacity (BOL) at PCS AC side	500 kWh
System output voltage range	810~1095V
Dimensions of battery unit (W * H * D)	2900*2450*1800mm
Weight of battery unit	6,200kg
Degree of protection	IP 54
Anti-corrosion grade	C3
Relative humidity	0 ~ 95 % (non-condensing)
Operating temperature range	-30 to 50°C (> 45°C derating)
Max. working altitude	3000m
Cooling concept of battery chamber	Liquid cooling
Fire safety equipment	Aerosol ,flammable gas detector and exhausting system
Communication interfaces	Ethernet
Communication protocols	Modbus TCP
Compliance	IEC 62619,IEC 63056,IEC 61000,IEC 62040,IEC 62477,UN 38.3
PCS cabinet data	
Nominal AC power	50kVA*5@45°C
Max.THD of current	<3%(at nominal power)
DC component	<0.5%(at nominal power)
Nominal grid voltage	400V
Grid voltage range	360-440V
Nominal grid frequency	50/60Hz
Nominal grid frequency range	45-55Hz,55-65Hz
Dimensions(W*H*D)	1800*2450*1200mm
Weight	1,800kg
Degree of protection	IP54
Anti-corrosion grade	C3
Allowable relative humidity range	0 ~ 95 % (non-condensing)
Operating temperature range	-30 to 50°C (> 45°C derating)
Max. working altitude	3000m
Communication interfaces	RS485, Ethernet
Communication protocols	Modbus TCP

Battery Size Range 3

Table 45. Technical Specifications for the Storage System for Grid-scale PV

Specification	Description
Battery Data	
Cell type	LFP
Battery capacity (BOL)	2236 kWh
System output voltage range	1123~ 1500V
General Data	
Dimensions of battery unit (W * H * D)	9340*2600*1730 mm
Weight of battery unit	26,000 kg
Degree of protection	IP 54
Operating temperature range	-30 to 50 °C (> 45 °C derating)
Relative humidity	0 – 95 % (non-condensing)
Max. working altitude	3000m
Cooling concept of battery chamber	Liquid cooling
Fire safety	Fused sprinkler heads, NFPA 69 explosion prevention and ventilation IDLH gases
Communication interfaces	RS485, Ethernet
Communication protocols	Modbus RTU, Modbus TCP
Compliance	CE, IEC 62477-1, IEC 61000-6-2, IEC 61000-6-4, IEC 62619
Grid Connection Data	
Max.THD of current	< 3 % (at nominal power)
DC component	< 0.5 % (at nominal power)
Power factor	> 0.99 (at nominal power)
Adjustable power factor	1.0 leading – 1.0 lagging
Nominal grid frequency	50 / 60 Hz
Grid frequency range	45 – 55 Hz / 55 – 65 Hz
Transformer	
Transformer rated power	4,000 kVA
LV/MV voltage	0.8 kV / 33 kV
Transformer cooling type	ONAN (Oil Natural Air Natural)
Oil type	Mineral oil (PCB free) or degradable oil on request

Results – BCR Analysis for Export Calculation

Table 46: BCR for tilted PV system with no feed in tariff

PV System Size (kW)	0% Export	5% Export	10% Export	15% Export	20% Export	25% Export	30% Export	35% Export	40% Export	45% Export	50% Export	55% Export	60% Export	65% Export	70% Export	75% Export	80% Export
10	2.26	2.13	2.00	1.86	1.73	1.60	1.46	1.33	1.20	1.06	0.93	0.80	0.66	0.53	0.40	0.27	0.13
15	2.37	2.23	2.09	1.95	1.81	1.67	1.53	1.39	1.25	1.11	0.97	0.83	0.70	0.56	0.42	0.28	0.14
20	2.42	2.28	2.14	1.99	1.85	1.71	1.57	1.42	1.28	1.14	1.00	0.85	0.71	0.57	0.43	0.28	0.14
40	2.45	2.30	2.16	2.01	1.87	1.73	1.58	1.44	1.29	1.15	1.01	0.86	0.72	0.57	0.43	0.29	0.14
100	2.69	2.54	2.39	2.23	2.08	1.93	1.78	1.63	1.48	1.33	1.17	1.02	0.87	0.72	0.57	0.42	0.26
300	2.81	2.66	2.51	2.36	2.20	2.05	1.90	1.75	1.60	1.44	1.29	1.14	0.99	0.84	0.68	0.53	0.38

Table 47: BCR for flat PV system with no feed in tariff

PV System Size (kW)	0% Export	5% Export	10% Export	15% Export	20% Export	25% Export	30% Export	35% Export	40% Export	45% Export	50% Export	55% Export	60% Export	65% Export	70% Export	75% Export	80% Export
10	1.96	1.84	1.72	1.60	1.48	1.37	1.25	1.13	1.01	0.90	0.78	0.66	0.54	0.42	0.31	0.19	0.07
15	2.05	1.92	1.80	1.68	1.55	1.43	1.31	1.18	1.06	0.94	0.81	0.69	0.57	0.44	0.32	0.20	0.07
20	2.09	1.97	1.84	1.72	1.59	1.46	1.34	1.21	1.08	0.96	0.83	0.71	0.58	0.45	0.33	0.20	0.08
40	2.11	1.99	1.86	1.73	1.60	1.48	1.35	1.22	1.10	0.97	0.84	0.71	0.59	0.46	0.33	0.20	0.08
100	2.34	2.21	2.07	1.94	1.80	1.67	1.54	1.40	1.27	1.13	1.00	0.86	0.73	0.60	0.46	0.33	0.19
300	2.46	2.33	2.19	2.06	1.92	1.79	1.65	1.52	1.39	1.25	1.12	0.98	0.85	0.71	0.58	0.44	0.31

Results – Minimum PV System Capacities for 50% Export

Table 48: 50% PV export calculations for C5OL with an archetype area of 12250 m^2

Climate Zone	Capacity (kW)	Consumption (kWh)	Production (kWh)	Export	W/m2
CZ 1	1,090	1,270,500	1,784,800	50%	89
CZ 2	776	970,600	1,281,600	50%	63
CZ 3	715	959,100	1,289,100	50%	58
CZ 4	715	856,300	1,101,400	50%	58
CZ 5	883	922,300	1,208,400	50%	72
CZ 6	763	801,500	991,000	50%	62
CZ 7	694	809,300	1,024,700	50%	57
CZ 8	670	783,400	910,500	50%	55

Table 49: 50% PV export calculations for C5OM with an archetype area of 2304 m^2

Climate Zone	Capacity (kW)	Consumption (kWh)	Production (kWh)	Export	W/m2
CZ 1	225	254,500	368,400	50%	98
CZ 2	155	185,100	256,000	51%	67
CZ 3	150	196,400	270,400	51%	65
CZ 4	140	172,900	215,700	50%	61
CZ 5	160	167,300	219,000	50%	69
CZ 6	150	155,700	194,800	51%	65
CZ 7	135	167,200	199,300	50%	59
CZ 8	130	187,200	176,700	50%	56

Table 50: 50% PV export calculations for C9A with an archetype area of 10368 m^2

Climate Zone	Capacity (kW)	Consumption (kWh)	Production (kWh)	Export	W/m2
CZ 1	570	1,063,300	933,300	50%	55
CZ 2	330	605,600	545,000	50%	32
CZ 3	330	674,100	595,000	50%	32
CZ 4	320	582,900	493,000	50%	31
CZ 5	365	582,600	499,500	50%	35
CZ 6	330	522,200	428,600	50%	32
CZ 7	300	535,400	442,900	50%	29
CZ 8	295	511,600	400,900	50%	28

Table 51: 50% PV export calculations for C9AS with an archetype area of 2048 m^2

Climate Zone	Capacity (kW)	Consumption (kWh)	Production (kWh)	Export	W/m2
CZ 1	165	305,900	270,200	51%	81
CZ 2	100	186,400	165,200	51%	49
CZ 3	100	218,400	180,300	51%	49
CZ 4	90	188,900	138,600	51%	44
CZ 5	100	162,400	136,900	52%	49
CZ 6	90	156,100	116,900	50%	44
CZ 7	95	196,000	140,300	51%	46
CZ 8	95	232,100	129,100	52%	46

Appendix B: Lighting Control

Equipment Tables

- **LCS -01 – Manual Control**

This system contains a very basic local light switch, it is a normal lighting switch most used to control the light circuit for ON/OFF operation only. Manual control also includes 1-10V and Phase dimming to control the voltage at a luminaire and thus its output.

Figure 33: LCS-01 - Local Switching zones arrangement

- **LCS -02 – Time Control**

This system contains a digital timer that can be installed in an electrical distribution board to allow for controlling the light circuits operation in specific areas for a certain period. This time switch must be programmed and adjusted to suit the ON/OFF period timing. Most advanced models can be controlled through Bluetooth facility. Timer controls can be utilized to provide an override of manual controls in suitable applications.

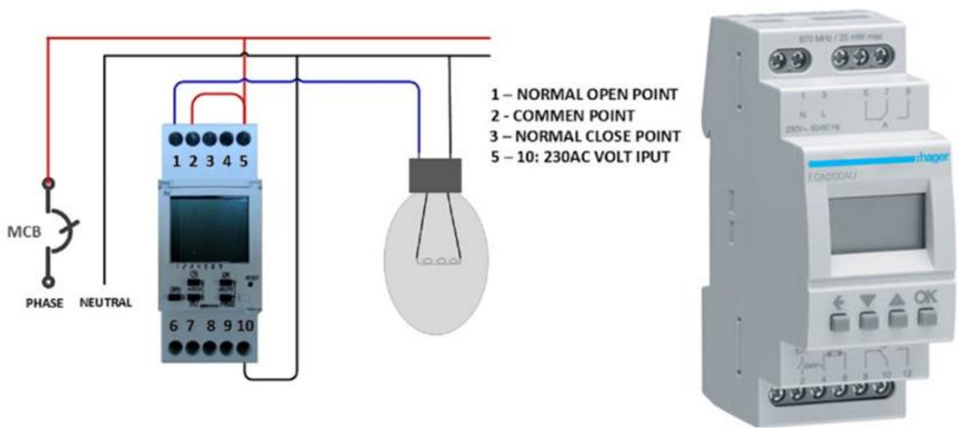


Figure 34: LCS-02 - Time switch operation

- **LCS -03 – Daylight linked sensor.**

This system contains a special type of sensor that measures and detects the amount of natural light and controls the exterior luminaires accordingly. The photocell sensor (PE) will be used for external lighting/Façade lighting and has to be positioned in an outdoor location that captured the lowest natural lighting level through the day, so that it has a fast response to control the outdoor lighting. These sensors are also utilized in buildings where a high level of natural light is available, specifically office and commercial premises with perimeter windows.

There is a lux sensor for indoor application which has to be positioned in the natural light area (adjacent to the windows) to control the interior artificial lighting according to the amount of natural lighting received in the area.

Figure 35: LCS-03 - Daylight sensors & PE sensors

- **LCS -04 – Presence/motion control**

This system relies on indoor sensors that can control the lights through people's motion/presence, the sensors technology can be ultrasonic, infra-red, microwave and Dynamic infra-red. These sensors have different cover ranges which must be considered in the design to make full coverage for all users and lighting switching zones.

Figure 36: LCS-04 – Motion/Presence sensors

- **LCS -05 – Digital Addressable Lighting Interface (DALI)**

This system is the most advanced and costly lighting control system. It is a networked-based system utilizing communications cabling between control points and luminaires. Networks are typically scalable based on the technology and the head-end software and hardware, functioning as a local (and in some cases, wireless) network looped back to main controllers. These devices are IP-based and require compatible drivers to operate on the network. Some systems can utilize electrical relays to provide low-level interfaces to non-IP electrical devices and circuits where it is not feasible to replace existing systems.

There are 4 common different categories of DALI system; Rapix, Dynalte, KNX and C-Bus. Each type has specific capabilities and benefits in the market; however each can accommodate the same baseline functions of intelligent control.

All the system components (i.e., light fittings, sensors, touch screen control panels, switches, …etc.) that are connected to DALI system, have to be specified as DALI compatible devices which can interface with the various points of the network. This system requires supervisory commissioning and training on site for the facility management staff. In some instances (C-Bus) specific certifications are required to conduct work on the proprietary system.

In addition to lighting, many of the protocols and systems are able to provide low-level interface and control to non-lighting systems (i.e. HVAC, ceiling fans, louvres etc).

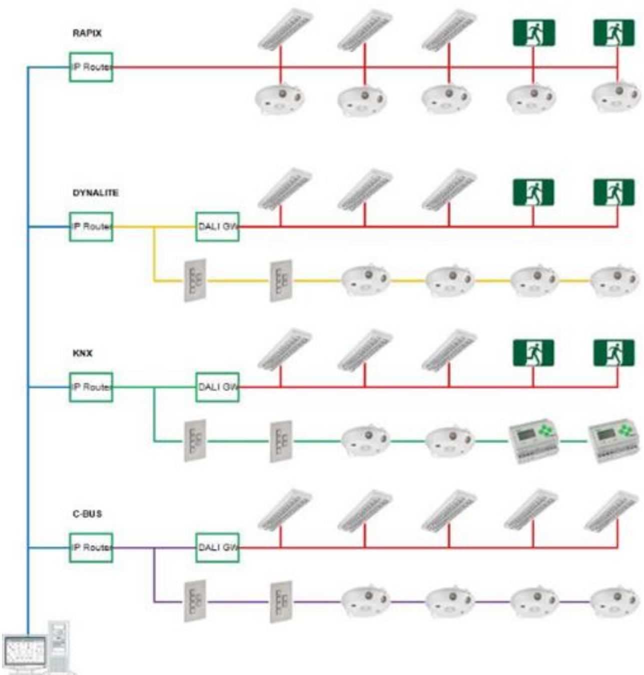


Figure 37: LCS-05 – Digital Addressable Lighting Interface (DALI)

Pricing

Table 52. Pricing information on different lighting controls

Lighting control system Type	Controlled lighting Load / Space area / Light fitting	Used Electrical Devices	Description/Photo	Cost per unit	Estimate commissioning Cost	Total cost
LCS-01 - Manual Control	- Not more than 100 m2 - Maximum controlled load 10 A per light switch, one gang.	- Light Switch one gang.	Supplier 1 250VAC,10A switch 1 gang. 	$16	$100	$116
LCS-02 - Automatic Control –Time Control	- <250m² if Overall area < 2000 m² - <1000 m² if overall area > 2000 m²	- Digital Time switch to be installed in DB Din Rail	Supplier 2 Electric Digital Time switch 	$1000	$250	$1250
LCS-03 - Automatic Control – Day light linked	<250 m² if Overall area < 2000 m² - <1000 m² if overall area > 2000 m² - Maximum controlled load 10A per unit.	- PE (cell) switch, to be installed to control outdoor lights or installed in the natural zone area for controlling indoor lights	Supplier 1 PE switch 	$120	$100	$220

LCS-04 - Automatic Control – Presence/motion control	- <250 m² if Overall area < 2000 m² - <1000 m² if overall area > 2000 m². - Detection zones Presence: 4 x 4 m max Radial: 5 x 5 m max Tangential: 7 x 7m max - Average controlled load for the sensors is 1500 Watt, 7A.	- Supplier 3 infrared presence detector for indoor application to control the indoor light fittings.	Supplier 3 infrared presence detectors 	\$300 standard / \$350 waterproof	\$100	\$400 standard / \$450 waterproof
LCS-05 - Automatic Control – Digital Addressable Lighting Interface (DALI)	Up to 160 light fittings per relay (500m²) Typically designed at 85%, with spare capacity - 425m² or 136 devices	Supplier 4's system contains the below devices: - Control Gateway and relay module - Interface devices including Panel switches, Touch screens and display. - Motion detectors. - Time switch and Power supply unit.	   	- 1 Ethernet Gateway & relay per floor \$2000. - 1 Panel switch \$300 - Touch Screens \$3000 - Time switch and power supply \$2500	\$2,000 per floor + 6/m² (or \$18.75/device) Usually \$5,000 per floor	Subject to number of motion detectors, over all cost will be around \$10,000 to \$ 15,000 for a simple system

Appendix C: EV Charging

Equipment Tables

Table 53: Example Installation Scenario 1

Class Building	EV Car parking spaces	Energy Metering	No. of EV Equipment (e.g., charger)	No. of Electrical board per store	Cost of EV Supply and install per charger	Cost of ancillary equipment/ Software
Class 2 Apartment building –10 storey 55 Apt. <u>Note:</u> Assuming 3 Basement Car Park storeys	100% of Car park spaces, assuming 2 car spaces per apartment, total 110 car parking spaces	Yes	110 EV Chargers, 37 chargers each Basement Storey	So based on NCC 2022, each storey will have 2 dedicated EV distribution boards (6 DBs in total)	Supply, installation and commissioning = $2988.00/unit, including $250 LMS. Supply, install Data cable =$586.00/unit Billing platform = $275/charge point Total = $3849/charger, this doesn't include any infrastructure fees (i.e., cable tray, cables, etc.)	$500/Unit Maintenance/ year
Class 3 hotel/motel, 2 storeys**, 1,000m2.**	Assuming total 35 car spaces, 20% (7) of car park spaces will be dedicated to EVs	Yes	7 EV Chargers	So based on NCC 2022, 2 dedicated EV distribution boards are required	Supply, installation and commissioning = $2988.00/unit, including $250 LMS. Supply, install Data cable =$586.00/unit Billing platform = $275/charge point Total = $3849/charger, this doesn't include any infrastructure fees (i.e., cable tray, cables, etc.)	$500/Unit Maintenance/ year
Class 5 office, 10 storeys**, 10,000m2.**	Assuming total 50 car spaces, 10% (5) of car park spaces will be dedicated to EVs	Yes	5 EV Chargers	So based on NCC 2022, 4 dedicated EV distribution boards are required, assuming 2 basement car parking levels	Supply, installation and commissioning = $2988.00/unit, including $250 LMS. Supply, install Data cable =$586.00/unit Billing platform = $275/charge point Total = $3849/charger, this doesn't include any infrastructure fees (i.e., cable tray, cables, etc.)	$500/Unit Maintenance/ year

Class Building	EV Car parking spaces	Energy Metering	No. of EV Equipment (e.g., charger)	No. of Electrical board per store	Cost of EV Supply and install per charger	Cost of ancillary equipment/ Software
Class 9 a/c, 2 storeys, 2000m2. <u>**Note:**</u> **Assuming 2 Basement Car Park storey**	Assuming total 150 car spaces, 20% of Car park spaces will be 30 car spaces should be EV car Spaces	Yes	30 EV Chargers	So based on NCC 2022, each storey will have 1 dedicated EV distribution board, (2 DBs in total)	Supply, installation and commissioning = \$2988.00/unit, including \$250 LMS. Supply, install Data cable =\$586.00/unit Billing platform = \$275/charge point Total = \$3849/charger, this doesn't include any infrastructure fees (i.e., cable tray, cables, etc.)	\$500/Unit Maintenance/ year

Table 54: Installation Scenario 2

Class Building	EV Car parking spaces	Energy Metering	No. of EV Equipment (e.g., charger)	No. of Electrical board per store	Cost of EV Supply and install per charger	Cost of ancillary equipment/ Software
Class 2 Apartment building –10 storey 55 Apt. Note: Assuming 3 Basement Car Park stores	100% of Car park spaces, assuming 2 car spaces per apartment, total 110 car parking spaces	Yes	110 EV Chargers, 37 chargers each Basement Storey	So based on NCC 2022, each storey will have 2 dedicated EV distribution boards (6 DBs in total)	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, this doesn't include any infrastructure fees (i.e. cable tray, cables, etc)	$500/Unit Maintenance /year
Class 3 hotel/motel, 2 storey, 1,000m2.	Assuming total 35 car spaces, 20% of Car park spaces will be 7 car spaces should be EV car Spaces	Yes	7 EV Chargers	So based on NCC 2022, 2 dedicated EV distribution boards are required	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, this doesn't include any infrastructure fees (i.e. cable tray, cable, etc)	$500/Unit Maintenance /year

Class Building	EV Car parking spaces	Energy Metering	No. of EV Equipment (e.g., charger)	No. of Electrical board per store	Cost of EV Supply and install per charger	Cost of ancillary equipment/ Software
Class 5 office, 10 storey, 10,000m2.	Assuming total 50 car spaces, 10% of Car park spaces will be 5 car spaces should be EV car Spaces	Yes	5 EV Chargers	So based on NCC 2022, 4 dedicated EV distribution boards are required, assuming 2 basement car parking levels	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, this doesn't include any infrastructure fees (i.e. cable tray, cables, etc)	$252.5/Unit for LMS $500/Unit Maintenance /year
Class 9 a/c, 2 storey, 2000m2. Note: Assuming 2 Basement Car Park storey	Assuming total 150 car spaces, 20% of Car park spaces will be 30 car spaces should be EV car Spaces	Yes	30 EV Chargers	So based on NCC 2022, each storey will have 1 dedicated EV distribution board, (2 DBs in total)	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, this doesn't include any infrastructure fees (i.e. cable tray, cables, etc)	$252.5/Unit for LMS $500/Unit Maintenance /year

Table 55: Detailed Supply and Cost/Number of EV Chargers for all Selected Archetypes by 2030

Scenarios	Class Building (Class 2)	EV Car parking spaces	No. of EV Equipment (e.g., charger)	Cost of EV Supply and install per charger	Cost of ancillary equipment/Software
Progressive Change	**Class 2** Apartment building –10 storey 55 Apt. **Note:** Assuming 3 Basement Car Park stores	100% of Car park spaces, assuming 2 car spaces per apartment, total 110 car parking spaces	110 EV Chargers, 37 chargers each Basement Storey **6.7% only will be projected to be used= 8 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger. Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 8 chargers = $21,592** **Cost of infrastructure for 164 m = $28,700**	$500/Unit Maintenance/year **Cost of 8 chargers = $4000**
Exploring Alternatives	**Class 2** Apartment building –10 storey 55 Apt. **Note:** Assuming 3 Basement Car Park stores	100% of Car park spaces, assuming 2 car spaces per apartment, total 110 car parking spaces	110 EV Chargers, 37 chargers each Basement Storey **11.1% only will be projected to be used= 13 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger. Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 13 chargers = $35,087** **Cost of infrastructure for 364 m = $63,700**	$500/Unit Maintenance/year **Cost of 13 chargers = $6500**

Scenarios	Class Building (Class 2)	EV Car parking spaces	No. of EV Equipment (e.g., charger)	Cost of EV Supply and install per charger	Cost of ancillary equipment/Software
Step Change	**Class 2** Apartment building –10 storey 55 Apt. **Note:** Assuming 3 Basement Car Park stores	100% of Car park spaces, assuming 2 car spaces per apartment, total 110 car parking spaces	110 EV Chargers, 37 chargers each Basement Storey **15.3% only will be projected to be used= 17 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 17 chargers = $45,883** **Cost of infrastructure for 578 m = $101,150**	$500/Unit Maintenance/year **Cost of 17 chargers = $8,500**
Hydrogen Export	**Class 2** Apartment building –10 storey 55 Apt. **Note:** Assuming 3 Basement Car Park stores	100% of Car park spaces, assuming 2 car spaces per apartment, total 110 car parking spaces	110 EV Chargers, 37 chargers each Basement Storey **20.8% only will be projected to be used= 23 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 23 chargers = $62,077** **Cost of infrastructure for 989 m = $173,075**	$500/Unit Maintenance/year **Cost of 4 chargers = $11,500**

Scenarios	Class Building (Class 2)	EV Car parking spaces	No. of EV Equipment (e.g., charger)	Cost of EV Supply and install per charger	Cost of ancillary equipment/Software
Progressive Change	**Class 3** hotel/motel, 2 storey, 1,000m2	Assuming total 35 car spaces, 20% of Car park spaces will be 7 car spaces should be EV car Spaces	7 EV Chargers **6.7% only will be projected to be used= 3 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 3 charger = $8,097** **Cost of infrastructure for 39 m = $6,825**	$500/Unit Maintenance/year **Cost of 3 chargers = $1,500**
Exploring Alternatives	**Class 3** hotel/motel, 2 storey, 1,000m2	Assuming total 35 car spaces, 20% of Car park spaces will be 7 car spaces should be EV car Spaces	4 EV Chargers **11.1% only will be projected to be used= 4 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 4 charger = $10,796** **Cost of infrastructure for 58 m = $10,150**	$500/Unit Maintenance/year **Cost of 4 chargers = $2,000**
Step Change	**Class 3** hotel/motel, 2 storey, 1,000m2	Assuming total 35 car spaces, 20% of Car park spaces will be 7 car spaces should be EV car Spaces	6 EV Chargers **15.3% only will be projected to be used= 6 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 6 charger = $116,194** **Cost of infrastructure for 105 m = $18,375**	$500/Unit Maintenance/year **Cost of 6 chargers = $3,000**

Scenarios	Class Building (Class 2)	EV Car parking spaces	No. of EV Equipment (e.g., charger)	Cost of EV Supply and install per charger	Cost of ancillary equipment/Software
Hydrogen Export	**Class 3** hotel/motel, 2 storeys, 1,000m2	Assuming total 35 car spaces, 20% of Car park spaces will be 7 car spaces should be EV car Spaces	7 EV Chargers **20% only will be projected to be used= 7 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 7 charger = $18,893** **Cost of infrastructure for 133 m = $23,275**	$500/Unit Maintenance/year **Cost of 7 chargers = $3,500**
Progressive Change	**Class 5** office, 10 storeys, 10,000m2	Assuming total 50 car spaces, 10% of Car park spaces will be 5 car spaces should be EV car Spaces	4 EV Chargers **6.7% only will be projected to be used= 4 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 4 charger = $10,796** **Cost of infrastructure for 58 m = $10,150**	$500/Unit Maintenance/year **Cost of 4 charger = $2,000**
Exploring Alternatives , Step Change and Hydrogen Export	**Class 5** office, 10 storeys, 10,000m2	Assuming total 50 car spaces, 10% of Car park spaces will be 5 car spaces should be EV car Spaces	5 EV Chargers **10% only will be projected to be used= 5 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 5 charger = $13,495** **Cost of infrastructure for 80 m = $14,000**	$500/Unit Maintenance/year **Cost of 5 charger = $2,500**

Scenarios	Class Building (Class 2)	EV Car parking spaces	No. of EV Equipment (e.g., charger)	Cost of EV Supply and install per charger	Cost of ancillary equipment/Software
Progressive Change	**Class 9 a/c**, 2 storeys, 2000m2. **Note:** Assuming 2 Basement Car Park storey	Assuming total 150 car spaces, 20% of Car park spaces will be 30 car spaces should be EV car Spaces	**6.7% only will be projected to be used=10 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 10 charger = $26,990** **Cost of infrastructure for 23 m = $4,025**	$500/Unit Maintenance/year **Cost of 10 charger = $5,000**
Exploring Alternatives	**Class 9 a/c**, 2 storeys, 2000m2. **Note:** Assuming 2 Basement Car Park storey	Assuming total 150 car spaces, 20% of Car park spaces will be 30 car spaces should be EV car Spaces	4 EV Chargers **11.1% only will be projected to be used= 4 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 4 charger = $10,796** **Cost of infrastructure for 58 m = $10,150**	$500/Unit Maintenance/year **Cost of 4 charger = $2,000**
Step Change	**Class 9 a/c**, 2 storeys, 2000m2. **Note:** Assuming 2 Basement Car Park storey	Assuming total 150 car spaces, 20% of Car park spaces will be 30 car spaces should be EV car Spaces	23 EV Chargers **15.3% only will be projected to be used= 23 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 23 chargers = $62,077** **Cost of infrastructure for 989 m = $173,075**	$500/Unit Maintenance/year **Cost of 23 charger = $11,500**

Scenarios	Class Building (Class 2)	EV Car parking spaces	No. of EV Equipment (e.g., charger)	Cost of EV Supply and install per charger	Cost of ancillary equipment/Software
Hydrogen Export	**Class 9 a/c**, 2 storeys, 2000m2. **Note:** Assuming 2 Basement Car Park storey	Assuming total 150 car spaces, 20% of Car park spaces will be 30 car spaces should be EV car Spaces	30 EV Chargers **20% only will be projected to be used= 30 chargers**	Supply, install and commissioning = $1865/unit, including $150 LMS. Supply, install Data cable =$586.00/unit Billing platform = $250/charge point Total = $2699/charger, Allow for $175/m for any infrastructure fees (i.e., cable tray, cables, etc.) **Cost of 30 chargers = $80,970** **Cost of infrastructure for 1650 m = $280,875**	$500/Unit Maintenance/year **Cost of 30 charger = $15,000**

Charging Projection Analysis

The demand for EV charging can vary depending on several factors, including user behaviour and preferences, electricity pricing structures, and infrastructure availability. It is universally true that EV charging demand increases specifically at night. Based on Figure 38 which is sourced from the CSIRO projections report, we can conclude that the peak charging time is the evening.

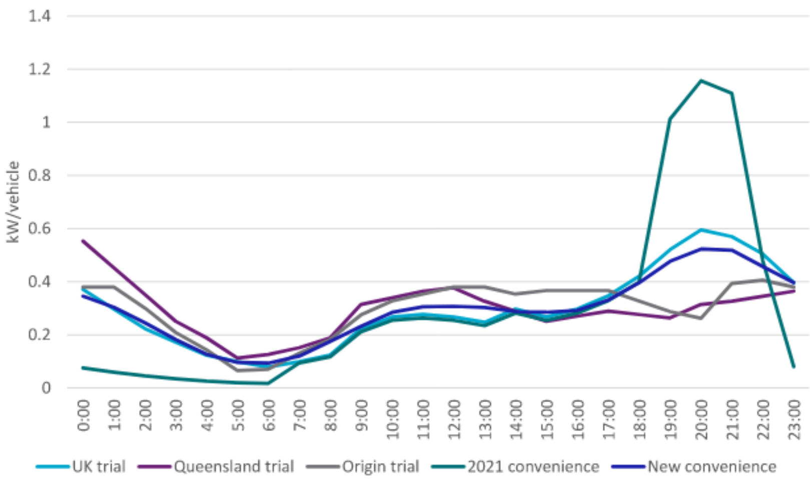


Figure 38: CSIRO Survey - Charging Demand Profile[29]

EV Charging Demand Profile

Class 2 & Class 3 Buildings

- Based on the number of projected EV cars, class 2/3 building charging profile will have a significant required charging demand especially in evening (peak) times. NCC 2025 should consider that EV chargers must deliver a minimum of 12kWh (class2)/48kWh (class 3) per vehicle between 6.00 pm to 7:00 am. This would require the use of an active dynamic load management system to adjust the charger output to the allowable minimum value.
- In weekdays, this charging demand will be reduced significantly in the middle of the day as the majority of EV cars are used out of the building. However, at night, the charging demand will increase.
- The CSIRO report[30] sources show weekend charging profiles are highly dependent on local and specific parameters (for example PV installation and battery storage). Generally, they could be found to have similar charging profiles to weekdays[31].

[29] Graham, P. CSIRO, 2022, Electric Vehicle Projections.
[30] Graham, P. CSIRO, 2022, Electric Vehicle Projections.
[31] “EV smart charge (Queensland) insights Report” (Energex and Ergon Energy Network 2022).

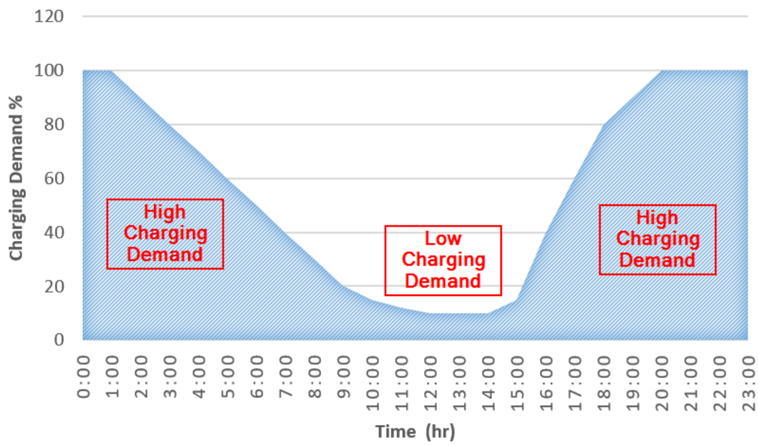


Figure 39: Calculated Weekday Charging Demand Profile for Class 2 and 3 Buildings

Class 5 Buildings

- Based on NCC 2022, an EV charger must provide minimum 12kWh per vehicle between 9.00 am to 5:00 pm. This time should be retained under NCC 2025, as this is the peak time of charging demand for a class 5 building. During this period, the importance of active dynamic load management system is high for reducing the charger output to achieve the required maximum demand.
- On weekdays, the charging demand is significantly increased during standard work hours, as EVs are being charged while the owners are working in their offices. This demand is reflected in the current minimum requirements of NCC 2022.
- On weekends, the required power amount can be reduced significantly as the car park use will be minimal.

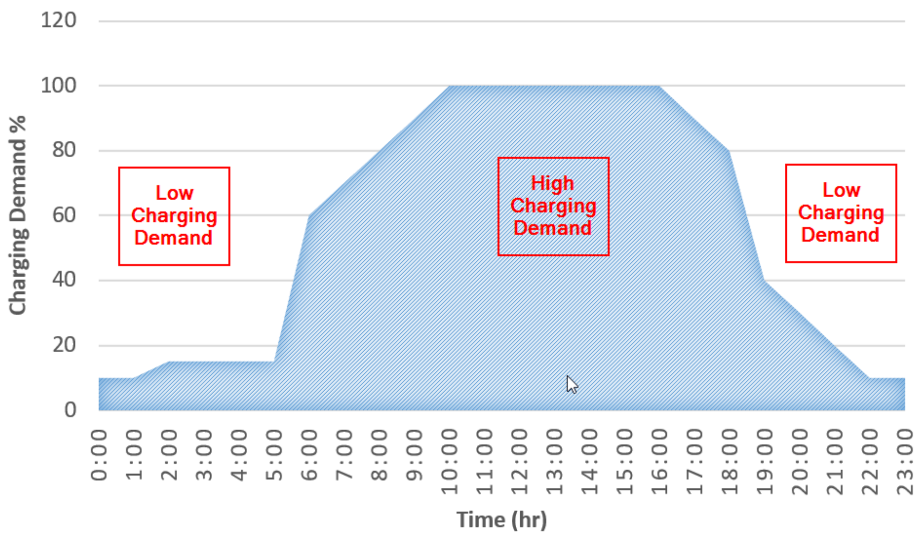


Figure 40: Calculated Weekday Charging Demand Profile for Class 5 Buildings

Class 9 Buildings

Based on above projection scenarios, we can expect the charging demand profile for class 9 buildings as follows:

- Based on NCC2022, EV charger must provide a minimum of 12kWh per vehicle between 9.00 am to 5:00 pm. This time should be retained under NCC 2025, as it is the peak time of charging demand for class 9 building. As a result, the active dynamic load management system is of greater importance during this period of time.
- From 9:00 am to 5:00 pm, the LMS will adjust the charger output to the minimum output power, then the charger power will be reduced from 5:00 pm till 9:00 am which is a nonpeak period.
- On weekdays, the full power amount is required as there are more EVs are being used within this class of buildings in the daytime. At night, the demand power will be reduced significantly as the EV cars will be charged at homes.
- On weekends, the total demand will be the same as the weekdays.
    - Typical visitor periods for seniors living and aged care buildings are Weekdays and weekends 9 am to 5pm

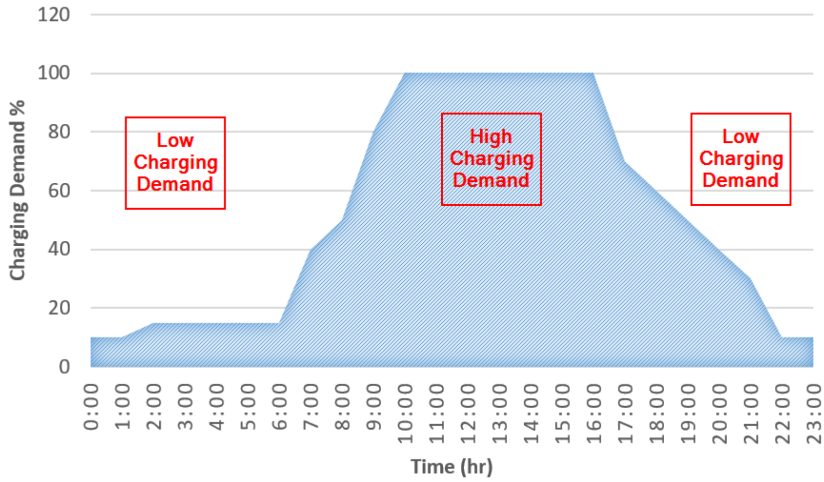


Figure 41: Calculated Weekday Charging Demand Profile for Class 9 Buildings