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Future energy storage trends

An assessment of the economic viability, potential uptake and impacts of electrical energy storage on the NEM 2015–2035

Report prepared for the Australian Energy Market Commission

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Executive summary

The appeal of energy storage in the Australian context is its ability to solve multiple challenges. These challenges include smoothing out intermittency, mitigating peak demand, maximising the value of on-site generation, integrating renewables into the grid through voltage and frequency support, and increasing the reliability of use of renewables off the grid. However, the growing integration of energy storage into Australia's National Electricity Market (NEM) could present additional economic, regulatory and technical challenges.

The Australian Energy Market Commission (AEMC), in conjunction with the Commonwealth Scientific and Industrial Research Organisation (CSIRO), has scoped a comprehensive program of work – the Integration of Storage Study – that will attempt to identify some of the challenges in integration of energy storage.

The companion report, *Electrical energy storage: Technology overview and applications* [1], reviewed the diverse range of available energy storage technologies that are relevant to the NEM. The review considered four energy storage technologies that are likely to see increased market uptake in the next two decades: advanced lead acid, lithium-ion (Li-ion), zinc bromide flow and sodium nickel chloride molten salt batteries.

This report analyses future energy storage trends over the period 2015–2035 for the shortlisted technologies, based on their comparative economics for different grid and customer-side applications. It identifies several key findings that will help in understanding the economic viability, potential uptake and impacts of storage on different parts of the electricity sector. These key findings are listed below.

Key finding 1: The costs of energy storage technologies will decline significantly in the future	• The future cost of energy storage technologies is subject to considerable uncertainty. • The battery cost is the largest component of a stationary energy storage system, but installation, inverter and maintenance costs must also be taken into account. For vehicles, efficient scale manufacturing is an important additional cost determinant. • Baseline costs of the more mature technologies (advanced lead acid and Li-ion batteries) are projected to decline by 53% by 2025 and by 68% by 2035. • Baseline costs of emerging technologies (zinc bromide and molten salt) are projected to decline rapidly: by 79% by 2025 and by 85% by 2035. • The projected battery costs in this study fall within the range estimated by other sources.

Key finding 2: The economic viability of storage in networks is plausible but case specific	• Discharging battery storage to reduce peaks in electricity demand across the grid may defer capital expenditure in the distribution or transmission grid. • Co-location of storage with solar photovoltaics (PV) could defer upgrades in existing voltage control or protection schemes and improve the power quality provided to customers. • Charging energy storage systems in preparation for peak load reduction potentially leads to decreases in cyclic thermal ratings of network infrastructure. • Battery storage is a potentially viable demand management strategy for transmission or subtransmission network operators under certain assumptions.
Key finding 3: Energy storage can reduce connection costs for large customers	• Battery storage co-located with a large load or small renewable generation site (< 30 MW) could potentially reduce the cost to connect to the grid. • Potential savings are likely to vary dependent on the diversity of loads or the generation profiles of commercial customers.
Key finding 4: The economic case for applying energy storage to reduce commercial electricity bills is sensitive to tariff structure	• This analysis was limited by the public availability of commercial electricity consumption profiles: • The economic viability of storage is sensitive to region, tariff structure and whether PV is already installed. Different views on what may constitute a reasonable payback period for a commercial customer are also relevant. • Installation of an integrated battery storage system with solar PV (IPSS) to commercial premises has the shortest payback period of the applications considered. • For baseline battery costs and large-size commercial customers in all NEM states, the payback periods for newly installed integrated storage and solar PV systems on a standard tariff (including a peak capacity demand charge as well as time of use energy charges) decline over the projection period from 7–9 years in 2015 to 4–5 years by 2035. • For baseline battery costs and large-size commercial customers in all NEM states, the payback periods for newly installed integrated storage and solar PV systems on a time-of-use only (TOU) tariff decline over the projection period from 17–29 years in 2015 to 7–11 years by 2035.

	• For commercial entities without solar PV, the retrofit of battery storage is more attractive in Queensland and Tasmania under standard tariff structures, and in New South Wales and South Australia under TOU tariff structures. • For commercial customers with PV, the retrofit of battery storage is attractive in Queensland and to a lesser extent Tasmania under standard tariff structures. • For commercial customers with PV under TOU tariff structures, the retrofit of battery storage is not economically viable. • Lower battery costs in the future will reduce the payback period most markedly for large commercial premises if they are adding storage to an existing PV system under a standard tariff.
Key finding 5: Energy storage could be viable for households in 7 years under current tariff structures	• The economic viability of storage is sensitive to region, tariff structure and whether PV is already installed. Different views on what may constitute a reasonable payback period for a residential customer are also relevant. • Storage is of greater value to households when it is installed in an integrated system with solar PV. • For baseline battery costs and large-size residential customers in most NEM states, the payback periods for newly installed storage and solar PV systems on a TOU tariff decline from 11–35 years in 2015 to 6–12 years by 2035. • For baseline battery costs and large-size residential customers in most NEM states, the payback periods for newly installed storage and solar PV systems on a flat tariff decline from 9–12 years in 2015 to 4–6 years by 2035. • For households without solar PV, battery storage provides the most value to households under TOU tariff pricing, particularly in New South Wales. • For baseline battery costs and large-size customers in most NEM states, the payback periods for battery storage for households without PV on a TOU tariff decline from 17–35 years in 2015 to 8–11 years by 2035. • For households with small capacity solar PV systems already installed, retrofitting battery storage does not provide significant additional benefits under flat tariff or TOU pricing.

	• Households with large loads will benefit more from storage than those with smaller loads. • Battery storage under capacity pricing appears to be unviable for households, based on the tariff structure with the minimum chargeable demand that has been assumed. • Lower battery costs in the future will reduce the payback period by 4–5 years for most time periods if battery systems are installed under TOU pricing.
Key finding 6: Energy storage in the NEM could compete against gas in 20 years	• Batteries are unlikely to be needed for load-following services in the NEM in the near term due to high existing capacity of gas and hydro peaking plant relative to demand. • If a gap in peaking capacity were to emerge, batteries could be cost competitive with gas peaking plant to provide load-following services in some NEM States by 2035. • Confidence in the results of this economic analysis could be improved with more temporally disaggregated, time-sequential review of battery and peaking plant applications.
Key finding 7: Electric vehicle uptake is likely to be subdued in the next decade	• The uptake of electric vehicles (EVs) is sensitive to future vehicle costs, projected oil prices and vehicle usage (kilometres per year) patterns. • In circumstances favourable to EVs, they will reach payback periods of 5–10 years between 2021 and 2028. In medium-case assumptions, this is delayed by a further 3–5 years.
Key finding 8: We should expect significant adoption of stationary and vehicle battery storage by 2035	• Under our assumptions about the relationship between payback period and adoption results in projected adoption of stationary and vehicle battery storage applications with GW capacity in the range of 5–30% of NEM generation capacity by 2035. • Under our TOU tariff case with solar PV, adoption of residential stationary battery storage reaches a maximum of 4.5% of households with solar by 2035. With no PV under a TOU tariff, residential PV reaches a maximum of 8% of households without solar under medium battery costs, or 18% under low battery costs. • Under our standard tariff case without solar PV, adoption of commercial stationary battery storage reaches 3–22% of commercial customers without solar by 2035. If battery costs decline faster, this penetration may increase to 5–30%.

	• Across the passenger and light commercial vehicle fleet, based on the economics of a medium-size vehicle, under our medium oil price and average kilometres travelled, adoption of battery EVs and plug-in hybrid EVs) reaches 17% and 13% of passenger vehicles by 2035.
Key finding 9: The deployment of stationary battery storage could have a significant impact on peak demand growth, but this impact could be greater with more coordination of price signals	• Under current tariff structures, battery storage tends to reduce peak demand during periods of higher charges. In particular, this applies during the highest TOU cost period for customers subject to that tariff. However, it is possible that peak demand times will shift in the future relative to those defined by current tariff structures. • Assuming that battery storage is discharged at system peak, a reduction in NEM maximum demand of 2.1–3.4 GW is possible by 2035. In percentage reduction terms, the most significant opportunities are in New South Wales and South Australia.

Abbreviations

Abbreviation	Meaning
AC	alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AS	Australian standard
BEV	battery electric vehicle
BNEF	Bloomberg New Energy Finance
CBD	central business district
CCS	carbon capture and storage
CHP	combined heat and power
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	concentrating solar power
DC	direct current
DG	distributed generation
DNSP	distribution network service provider
DoD	depth of discharge
DOE	US Department of Energy
DSM	demand side management
EGS	enhanced geothermal system
ECC	emergency cycling capacity
EIA	Energy Information Administration

EPRI	Electric Power Research Institute
ES	energy storage
ESS	energy storage system
EV	electric vehicle
FCAS	Frequency Control and Ancillary Services
FiT	feed-in tariff
GALLM	Global And Local Learning Model
GW	gigawatt
GWh	gigawatt-hour
ha	hectare
HV	high voltage
ICE	internal combustion engine
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IGCC	integrated gasification combined cycle
IPSS	integrated photovoltaic storage system
km	kilometres
kV	kilovolt
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt-hour
LFE	lithium iron phosphate
Li	lithium
LV	low voltage

MRL	manufacturing readiness level
MV	medium voltage
MVA	megavolt ampere
MW	megawatt
MWh	megawatt-hour
NEM	National Electricity Market
NMC	nickel manganese cobalt oxide
O&M	operations and maintenance
OLTC	on-load tap changers
p.a.	per annum
pf	pulverised fuel
PHEV	plug-in hybrid electric vehicle
ppm	parts per million
PV	photovoltaic
R&D	research and development
RMI	Rocky Mountain Institute
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SOD	stage of discharge
SWER	single wire earth return
T&D	transmission and distribution
TOU	time of use
TRL	technology readiness levels
V	volt

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1 Introduction

A key assumption of electricity system design has been that electricity is too costly to store but must be available when needed by the load. Recent reductions in the cost of battery storage mean that it is timely to revisit this assumption. This report provides projections of the potential future costs of battery storage and examines whether, under those projections, battery storage is viable across a range of possible customer cases. Based on the outcome of the analysis of economic viability, it provides projections for the adoption of battery storage in the Australian electricity grid and calculates the impact of that adoption on the profile of electricity demand.

The report considers only battery storage technologies, and covers four battery chemistries described in the companion report, *Electrical energy storage: Technology overview and applications* [1].

The economics of each application is considered from the point of view of the investor, whether that be a network business, commercial or residential customer, or vehicle owner. This is important because we assume that battery adoption will take place only if there is a benefit to an investor, whatever the broader benefits or costs to other parties may be. We explore multiple tariff structures and, on the end-user side, take into account whether a customer has solar panels. Results are generally presented by each of the states that are included in Australia's National Electricity Market (NEM).

A major innovation is that this report provides one of the first battery cost projections derived using a consistent, robust, transparent and peer-reviewed methodology. Generally, the methodology and assumptions applied to arrive at other projections available in the literature are not disclosed in sufficient detailed to be understood. The battery cost projections are an important foundation for all of the proceeding analysis of economic viability and adoption of battery storage.

Figure 1 indicates the approach used in this report.

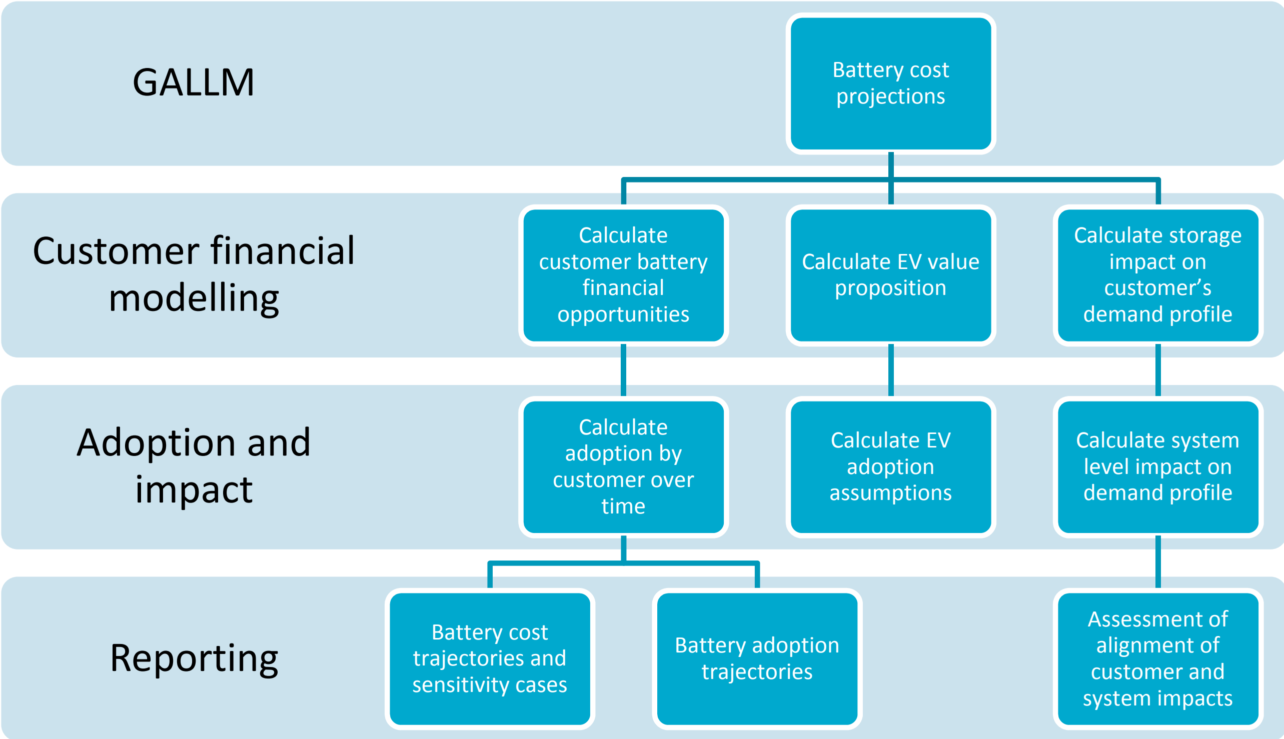

Figure 1: Overview of report method and structure

EV, electric vehicle; GALLM, Global and Local Learning Model

Part I of the report outlines the assumptions, method and results of applying the Global and Local Learning Model (GALLM) developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) to project battery costs to 2035. Part II uses the battery cost projections to examine each of the customer cases to determine the economic viability of battery storage, in many case calculating payback periods as the main reporting variable. That information is then used to develop adoption profiles over time to 2035. The impact of battery storage on load profiles at the customer and system level are calculated based on these adoption projections. The final section summarises the results of the analysis and draws conclusions on the potential role of storage in the electricity system.

Part I Future cost of battery storage technologies

2 Energy storage cost components

Batteries are frequently sold as a standalone item. However, for a battery to function as an energy storage (ES) device, it requires other components, which interact to form an ES system (ESS). This section describes the components of an ESS, and their current and future capital cost projections; it also discusses the methodology used to project the future costs.

2.1 Battery capital cost

The CSIRO companion report [1] examined the technical potential, level of deployment and applications of a wide range of ES technologies, and identified five battery chemistries with the most potential. These chemistries are advanced lead acid, lithium iron phosphate (LFP), lithium nickel manganese cobalt oxide (NMC), zinc bromide and molten salt. The technical readiness level (TRL), manufacturing readiness level (MRL)[1] and current cost ranges of these chemistries are shown in Table 1. This report treats LFP and NMC as a single technology, because they both fall under the umbrella of 'lithium-ion' (Li-ion) batteries, and have similar cost and technical performance.

The cost data in Table 1 were compiled from various sources, including company websites, local distributors, company presentations, reports and journal papers. Not included are costs of packaged systems (e.g. those manufactured by Bosch, in which consumers buy an integrated system that contains the batteries, inverter, battery management system and other power electronics as a packaged system), because it is not possible to separate out the cost components to extract the battery cost.

Table 1: Maturity level characteristics and current cost range of energy storage technologies

Technology	TRL	MRL	Minimum cost ($/kWh)	Average cost ($/kWh)	Maximum cost ($/kWh)
Advanced lead acid	8	7	750	875	1000
Li-ion (LFP and NMC)	9	9	443	543	562
Zinc bromide	9	8	1101	1188	1276
Molten salt*	8	7	1500	1500	1500

LFP, lithium iron phosphate; Li, lithium; MRL, manufacturing readiness level; NMC, nickel manganese cobalt oxide; TRL, technical readiness level

Sources: [2–16]

*only a single reference source available

[1] See the CSIRO companion report [1] for definitions

2.1.1 Methodology for determining battery cost projections – GALLM

For this study, we used GALLM to project the future cost of batteries [17]. GALLM is solved as a mixed integer linear program in which total costs of electricity supply are minimised to reach a given level of electricity demand over time. The model features endogenous technological learning at both the global and local scale. Endogenous technological learning means that the electricity technology mix and the cost of each electricity generation technology are solved simultaneously as outputs from the model, based on the learning curves (also known as experience curves) provided as inputs.

Learning curves refer to the observed phenomenon that the costs of new technologies tend to reduce with the cumulative production of the technology (i.e. 'learning by doing'). Also, costs tend to reduce by an approximately constant factor for each doubling of cumulative production [18–20]. This observation makes it possible to create cost projections based on projections of the future uptake of a technology. Projections are created from a mathematical equation as follows:

$$IC_t = IC_0 \times CC_t^{-b}$$

where IC is the investment cost of a technology at CC cumulative capacity at a given future point in time t, IC_0 is the investment cost at a given starting period or capacity, and b is the learning index. This index is related to the learning rate as follows:

$$LR = 100 - 2^{-b}$$

where LR is the learning rate, represented as a percentage.

Any mathematical equation or model is only as useful as the data it applies. For technologies that have already been deployed, the learning rate can be observed. For very new technologies, not yet deployed, no historical learning rate can be calculated. Instead, assumed values based on learning rates of similar previously emerging technologies are often applied. Component learning can be used where technologies are broken down into their components; where components are shared between different technologies (e.g. steam turbines), the cost reductions are shared among all the technologies that use a particular shared component [21, 22].

Projections of the global and local uptake of a technology need to be generated to project costs. However, uptake itself depends on projected costs. To resolve this interdependency, models such as GALLM are applied to project cost and uptake simultaneously.

The main advantage of the learning curve approach is that it provides an objective and transparent methodology for assigning a timeline to technology cost improvements. Simultaneously, it provides a projection of the global technology mix at any point in time. A disadvantage of the learning curve approach is that it cannot provide any guidance about exactly what processes or material components changed to arrive at the future cost level. Also, it cannot identify breakthroughs in technological development or bottlenecks that need to be addressed. Thus, if not constrained in some way, the learning curve approach can lead to unrealistically low costs. These issues are addressed by implementing a lower limit (informed by engineering and science estimates of the maximum potential of a technology) or by reducing the learning rate over time as the technology matures, based on observed cost outcomes of other technologies.

Factors that can affect the learning curve

The price of a technology does not always decrease at a steady rate with an increase in the number of units produced. Various factors can affect the price and thus the actual slope of a learning curve:

1. *Technology structural changes*, which result in a dramatic improvement in the technology, accompanied by a sharp increase in the learning rate and decrease in cost. This may happen, for example, if the promise of new liquid metal battery chemistries are realised [23].
2. *Market forces*, which can have a large influence when learning curves are constructed using price rather than cost data. When there is high demand for a product and few suppliers, the price can remain high or even increase, leading to a perceived decrease in the learning rate. This was the case in the mid to late 2000s, for example, for wind turbines and photovoltaic (PV) panels.
3. *Government policy and research and development (R&D) spending*, which can help push some technologies down the learning curve when they are given government support for demonstration projects and so on. This type of support is especially important for emerging and early stage technologies that need to move beyond the demonstration phase.
4. *Compound or component learning*, where technologies are a combination of different parts, each of which has a different rate of learning. For example, if learning is saturated in one component (i.e. all low-cost opportunities have been used), the learning rate for the technology as a whole reduces.
5. *Country or regions in which the learning has occurred*, given that local rates of learning differ from global rates, since uptake of the technology is on a different scale.

In GALLM, we have dealt with each of the issues listed above by doing the following:

- *Issue 1*: Examining various technology development scenarios based on expert knowledge.
- *Issue 2*: Including the 'penalty constraint' [17], which increases the price of a technology when demand for that technology is greater than an estimate of the historical production capacity.
- *Issue 3*: Forcing GALLM to construct small capacities of early learning and emerging technologies, to represent government R&D support for demonstration projects.
- *Issue 4*: Splitting technologies into their components, with separate learning rates for different components, and sharing components between different technologies when those technologies comprise the same component; for example, carbon capture and storage (CCS) is shared between four different electricity generation technologies.
- *Issue 5*: Including local (regional level) and global learning rates, which depend on the particular technological component, and where it is manufactured or installed.

The different stages of technology learning

As technologies progress through different levels of technical and commercial maturity, their learning rate reduces [20]. This is shown schematically in Figure 2, where the slope of the curve represents the learning rate.

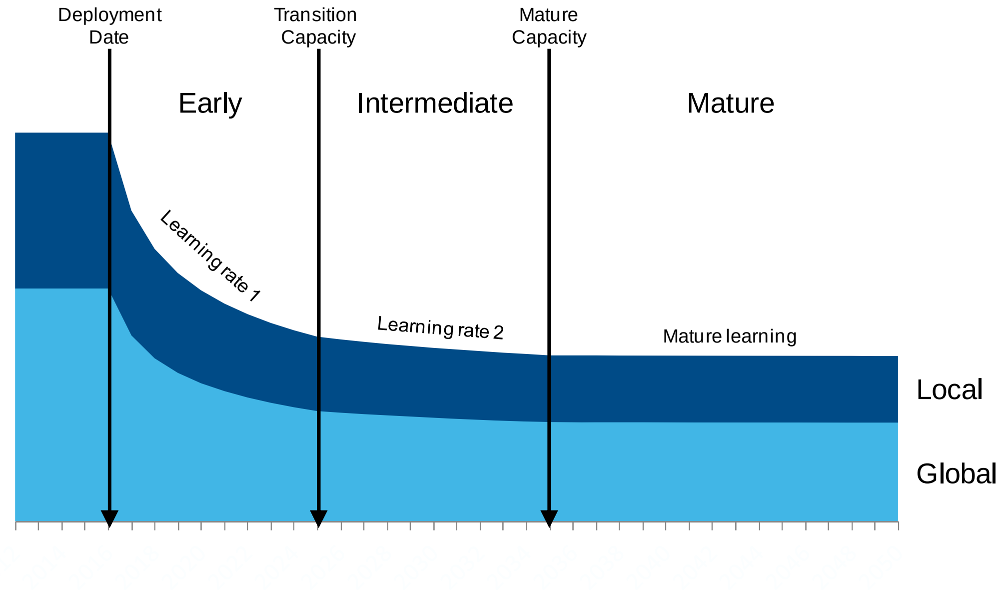

Figure 2: Schematic of changes in the learning rate as a technology progresses through its development stages after commercialisation

During the early commercialisation stages, learning rates may be around 20%. During the pervasive diffusion stage or intermediate stage, they may fall to around 10%. Finally, when the technology is mature, little or no learning may be observed [20].

Accordingly, in GALLM, the learning rates for technologies and their components differ, depending on the maturity of the technology. For the emerging and early learning technologies, two learning rates are applied, with the second, lower learning rate beginning when the technology reaches the diffusion or intermediate stage (or 'transition capacity'), as shown in Figure 2. In the case of electricity generation technologies, this tends to occur once a technology has been around for at least 50 years [24, 25]. This study used the GALLM methodology to determine appropriate learning rates for batteries.

More detail on GALLM can be found in Section 9 and [17]. However, batteries are a new addition to GALLM for this study; hence, they are not discussed in [17].

2.1.2 The learning rate of batteries

To include batteries in GALLM for this study, it was necessary to determine a learning rate for each battery type. The rates were based on an understanding of the technical characteristics of the batteries, as described in the CSIRO technical report [1], and on estimates from the literature.

Advanced lead acid batteries

Advanced lead acid batteries are a new technology and they differ from the common lead acid batteries seen in vehicles. The advanced batteries have features similar to a super capacitor, which contributes to their unique ES performance [1]. They are used in hybrid electric vehicles (EVs) and as an ES device on a demonstration or early commercial scale. Advanced lead acid batteries are at a high TRL and MRL; also, they are relatively low cost compared to other ES devices [1. Because of these characteristics, they have a lower potential for cost reduction than other battery types examined in this report. They have been assigned a learning rate of 9%, which is the same as that for EV and Li-based batteries [14]. This learning rate is consistent with technologies reaching the intermediate stage of development (see Figure 2); for example, 9% is the learning rate used for offshore wind.

Li-ion batteries

LFP and NMC batteries both fall under the broad category of Li-ion batteries, which have been used for many years in consumer electronics [26]. As such, their level of maturity is high. The construction of the Tesla Gigafactory, which will increase the supply of these types of batteries, is expected to bring costs down significantly [27]. A recent *Nature Climate Change* paper examined historical cost reductions in battery packs for EVs, including these types of chemistries [14]. The learning rate calculated by the authors of that study was 9% for the whole industry. Therefore, we used that learning rate in our modelling.

Zinc bromide batteries

Zinc bromide batteries are a type of flow battery that (along with vanadium redox) have been used on the demonstration or early commercial scale for some time for utility-scale projects. Their technical maturity is high; also, their cost is quite high [1]. Given these characteristics, in particular the fact that these batteries have yet to benefit from economies of scale in manufacturing, they were assigned a higher learning rate of 15%. This rate is consistent with other technologies at the same level of overall maturity; that is, early learning or emerging (see Figure 2). For example, concentrating solar power (CSP) has the same learning rate, as do Li-ion batteries in their early stages of commercial application [26].

Molten salt batteries

The chemistry used in molten salt batteries has been around for many years. However, it has not been deployed commercially on a large scale; these batteries have mainly been used in niche applications. Given the high technical complexity of these batteries [1], they were assigned a learning rate of 15%.

2.1.3 Batteries in GALLM

If two or more technologies have similar learning rates and applications, but one is lower cost than the other, GALLM will always choose the lowest cost option (unless that option triggers the penalty constraint and thus is no longer the lowest cost option), because the objective function in GALLM is to minimise total cost. This is called technology 'lock-in'. Given that advanced lead acid and Li-ion batteries have similar characteristics and the same learning rate, GALLM would only choose to construct one of each type of battery; that is, it would choose either advanced lead acid or Li-ion. The same applies to zinc bromide or molten salt, which again have similar characteristics and the same learning rate. Also, GALLM is a large and complex model; hence, it can take more than a day to produce an optimal solution. Each additional learning curve increases the complexity and solve time substantially. Therefore, only two battery chemistries were included in GALLM. The battery chemistry that was not modelled was given the same annual percentage cost reduction as the battery chemistry that was modelled and that has the same learning rate. The battery chemistries modelled were Li-ion and zinc bromide. Therefore, the annual percentage cost reduction of Li-ion batteries was applied to advanced lead acid batteries, and that of zinc bromide batteries was applied to molten salt batteries. Li-ion and zinc bromide were chosen because, given current market and technology dynamics, they are the most likely to have substantial market share.

To ensure that GALLM took into account uptake of batteries along with the electricity generation technologies, batteries were required to contribute to meeting electricity demand in several ways:

- reducing demand at the end user
- reducing peak demand across the network
- providing peaking capacity across the network.

Each of these methods is discussed below.

Reducing demand at the end user

Reducing demand at the end user (household and commercial scale) involves combining storage with PV into one technology comprising several components. The components are PV modules, and PV balance of plant, inverters and batteries. Each component has a separate learning rate. Only battery types that are considered to be suitable for this type of application (e.g. Li-ion) are allowed to contribute to this application in GALLM. The model includes a financial incentive for this application of ES: the avoided cost of retail electricity from self-consumption of electricity generated from PV by storing it in batteries. Such incentives are found in various countries in Europe that have large amounts of installed PV capacity and high retail prices, such as Germany and Italy, and they came about with the reduction or elimination of feed-in tariffs (FiT) for PV. The incentive in 2015 is assumed to be the Organisation for Economic Co-operation and Development (OECD) average retail price of $0.30/kWh (converted to 2015 AUD) [28, 29]. Thus, in GALLM, every kWh of electricity generated by PV plus storage in the developed world has a value of –$0.30/kWh, which is the avoided cost of retail electricity. The developed world includes Australia, Canada, Europe, Japan, the United States (US), and so on. Because batteries are sold on a global market and have a global learning rate, uptake of batteries in any region reduces the cost via learning in all regions. Some regions have incentives for installing batteries, such as upfront payments. However, due to the diverse nature of these incentives and the fact that this version of GALLM only has three regions (Australia, rest of developed world and developing world), it was not possible to include the full diversity of country-specific incentives available.

Reducing peak demand

Reducing peak demand across the network due to customer load (i.e. the traditional summer and winter peaks) is another way to meet demand. In this application, batteries compete with other peaking technologies, such as gas peaking plant. Because this is an energy application, only zinc bromide batteries were allowed to contribute to it. In the case of batteries, they were assumed to be charged during off-peak periods and discharged during peak periods. Gas peaking plant was assumed to run during peak demand periods only.

Providing peaking capacity across the network

Providing peaking capacity across the network to fill supply gaps is a further way to meet demand. With increasing amounts of intermittent technologies expected to be deployed, combined with reductions in base load plant in wholesale markets, increasing amounts of back-up capacity are required in case any technology cannot produce electricity [30]. Peaking capacity technologies may not actually need to produce any electricity but they were included as they form part of the approach to network system reliability management. Because this is a power application at the utility scale, only Li-ion batteries were allowed to contribute to this application, competing against gas peaking plant.

Other considerations

The technical characteristics of the batteries, such as depth of discharge (DoD) and lifetime, were included in GALLM, along with the cost of the batteries. Li-ion batteries were considered as a component in GALLM; these batteries are installed either in the deployment of PV plus batteries or to reduce peak electricity demand. This potentially higher level of uptake, due to co-learning across two applications, should result in greater cost reductions because it helps to push Li-ion batteries down the learning curve at a faster rate.

2.1.4 EVs in GALLM

To understand the global change in costs of various battery types through learning, ideally both the stationary and transport applications would be modelled. To this end, we developed a model of the global transport market (GALLM-T) that includes several major technology components within vehicles and along selected fuel supply chains (to study learning by deployment in supply chain components such as refining plant). In this study, we were interested in learning only in relation to battery applications in electric road vehicles.

EV uptake was generated in GALLM-T under the same carbon price and oil price scenarios as in GALLM. Under these scenarios, by the year 2035 some 30% of demand for passenger travel in cars is projected to occur in EVs. The 2035 demand for transport of goods using light commercial vehicles (LCV) is projected to be even higher: 90% in EVs. LCVs suit electrification more than most other modes of road transport because they tend to travel short distances from a base where they can be recharged. These applications result in a high level of battery uptake in GALLM-T; the cumulative capacity of all batteries reaches 33 TWh by 2035.

The level of uptake of batteries is projected to be significant and is thus expected to affect the cost, as calculated using learning by doing. Therefore, the capital cost of Li-ion batteries was adjusted to take this additional application into account.

2.1.5 Rooftop PV in GALLM

The inclusion of PV in GALLM has been covered extensively elsewhere [17], so only a summary is provided here. GALLM includes three different PV technologies: large-scale PV, rooftop PV and rooftop PV+storage. PV has been split into its components – modules and balance of plant (BOP) – and the learning of each component is shared among the different PV technologies. The modules have global learning and the BOP has local learning. In addition, these components are common to all types of PV. Thus, when a large-scale PV plant is constructed in the model, the cost of modules is reduced for all PV technologies. Although the component costs are the same for all PV technologies, there are differences in their treatment in GALLM:

- because of economies of scale in construction, large-scale PV is about 30% lower cost than rooftop PV; therefore, an additional cost reduction factor has been applied to large-scale PV
- rooftop PV and rooftop PV+storage do not have any transmission losses included (since energy use is at site)
- large-scale PV has a higher capacity factor to take into account tracking technology, the absence of shading and the expectation that any large-scale PV installations will be in sunnier locations than rooftop PV.

The learning rate of modules is assumed to be 20%.

2.1.6 Sensitivity of GALLM

GALLM relies on a wide range of input data (e.g. capital costs, operations and maintenance [O&M] costs, fuel efficiency, emissions, fuel costs, capacity factor and existing capacity) for 21 different electricity generation technologies and, in this study, two different battery types. However, the values of these parameters are well understood and thus do not affect the model's sensitivity. The parameters that can affect the results are those that are less well understood, such as future schemes for reducing emissions, future oil and gas prices, the learning rates assumed and the level of the penalty constraint. The sensitivity of GALLM to the level of the penalty constraint and the learning rates were explored in [17] and are summarised below.

In the form used in this study, the penalty constraint leads to smoother capacity additions through the imposition of higher costs for employing a high share of any technology. The constraint is not so rigid that it blocks emerging technologies from entering the marketplace. The sensitivity analysis showed that, without the penalty constraint or with a lower financial penalty, technologies could be installed in large chunks, or in a boom and bust cycle, which is not realistic. A higher financial penalty allows for the addition of more emerging technologies.

To explore the sensitivity of the model to the learning rates of the ES technologies taken into account, we altered the learning rates by ±25% to provide a range of battery capital costs. All the learning rates that were used are shown in Table 2. These values are within the range of learning rates that have been observed for many different technologies [31].

Table 2: Learning rates (%) assumed for battery technologies

Technology pair	Minimum LR	Base level LR	Maximum LR
Li-ion and advanced lead acid	6.75	9	11.25
Zinc bromide and molten salt	11.25	15	18.75

Li, lithium; LR, learning rate

Three different carbon price and matching oil price scenarios produced by the IEA (current policies, new policies and 450 ppm) were modelled in GALLM for this study [32]. Carbon price scenarios affect the cost of fossil fuel generation, which in turn affects the competitiveness of renewable technologies. Oil price scenarios are less important because there is only one oil-based technology in GALLM: oil thermal generation. The variation in battery capital cost trajectories between the different carbon price and oil price scenarios was negligible. Therefore, only the results of the new policies scenario are shown in later sections. To deal with gas price uncertainty, instead of assuming a gas price trajectory, a cost curve was used in which the price of gas increases depending on gas consumption [17].

2.2 Inverter and installation costs

Inverters that can both transmit and receive electricity (more correctly referred to as inverter–chargers) are required for batteries. These are more complex than the usual PV inverters that only transmit electricity; however, some high-end PV inverters have this two-way capability. Off-grid inverters are more complex again. The level of complexity, manufacturing quality and reliability is reflected in the cost of an inverter. A wide range of current costs was found for battery inverters, as shown in Table 3 [11, 33–37].

Installation costs at scales larger than residential were calculated based on the formulas given below. Costs for medium-scale (> 7 kWh to < 1 MWh of batteries installed) installations were calculated on a pro-rata basis, based on the residential installation costs:

$$Installation\ cost\ (\$) = 400 + \frac{400}{7} \times 0.5 \times (Cap - 7)$$

where 400 refers to the residential installation costs in AUD, 7 is the average kWh capacity of residential battery storage, and Cap is the capacity of the installed batteries in kWh.

On scales of greater than 1 MWh of battery installed capacity, the following equation was used to calculate combined inverter and installation costs [37]:

$$Installation\ and\ inverter\ cost\ (\$) = 1.7 \times battery\ cost\ (\$)$$

In the case of the bundled residential PV+storage systems, the installation and inverter costs of the battery system were halved, to adjust for expected economies of scale involved in installing a bundled system.

Table 3: Assumed current inverter and installation costs

Min cost ($/kW)	Average cost ($/kW)	Maximum cost ($/kW)	Installation cost residential ($)
514	813	1410	400

The lifetime of an inverter is similar to that of a battery; thus, in the modelling it was assumed that when the batteries are replaced, the inverters are also replaced.

Inverters were found to have a 10% learning rate [38]. This figure was applied to all inverters in GALLM. Installation costs were assumed to reduce at the same rate as mature technologies in GALLM (i.e. at 0.05% per year) [17].

2.3 Energy storage maintenance costs

There is little information in the literature on ES O&M costs. This situation may reflect the fact that few ESS incorporating batteries have been installed; hence, these costs are largely unknown. This study used the O&M costs determined in a 2015 review of ESS O&M cost estimates [39]. The

O&M costs are low compared to the capital cost, and thus should have a negligible impact on the potential uptake of ESS in any application (Table 4).

Table 4: Assumed operations and maintenance costs for batteries

Technology	Application related to cost	Fixed O&M cost	Variable O&M cost ($/MWh)
Advanced lead acid	Large scale (> 1 MW)	$5/kW-year	0.5
Li-ion	Residential and Medium Scale	$300 every 5 years	
Li-ion	Large scale (> 1 MW)	$10/kW-year	3.1
Zinc bromide	Large scale (> 1 MW)	$6/kW-year	0.9
Molten salt	Large scale (> 1 MW)	$5/kW-year	2.6

Li, lithium; O&M, operations and maintenance

Because of the lack of information and the low O&M cost relative to the capital cost, we have assumed that no cost reduction will occur in O&M.

3 Battery performance

Battery performance parameters were required in order to perform the modelling and to calculate the levelised cost of batteries. The battery performance parameters assumed in the modelling are shown in Table 5. These values are a distillation of a range of values presented in Table 14 of the CSIRO ES technical report [1]. The values are indicative only and do not represent the performance of any individual commercial battery but rather represent the technology as a whole. The two Li-ion chemistry types described in the CSIRO ES technical report, LFP and NMC, have been combined into one type called Li-ion in this study. This is because there is a strong degree of overlap in the performance and cost of these batteries which would have resulted in similar future cost trajectories.

Table 5: Performance characteristics of batteries used in the economic assessment

Technology	Advanced lead acid	Lithium-ion	Zinc bromide flow battery	Molten salt
DoD (%)	40	90	100	80
Cycle life (No. cycles)	4000	4000	1500	4000
Lifetime (years)	10	10	10	10
Round-trip efficiency (%)	90	90	75	85
Suitable application (E, P or both)	E	Both	E	E
Typical charge time (hours)	1	1	6.5	5
Typical discharge time (hours)	1	1	6.5	5
Modelling temperature (ºC)	25	25 ±2		270 to 350 battery internal with 25 ambient temperature

DoD, depth of discharge; E, energy; NMC, nickel manganese cobalt oxide; P, power; SoNick, sodium nickel

Calculated for 80% of initial capacity for all batteries.
Charging and discharging times given for the cycle life number determination test.
Data calculated from manufacturers’ data sheets.

All of the parameters shown in Table 5 affect the performance and application of batteries. However, only the DoD, cycle life, lifetime and round-trip efficiency are used to calculate the levelised cost:

- The *DoD* refers to the amount of energy that is actually usable in a battery. The DoD is not a hard limit, but if a battery is used beyond its DoD its performance tends to degrade. Therefore, we assumed that batteries would not be discharged beyond their DoD.

- The value of the *cycle life* represents the number of cycles of complete discharge (down to the DoD) that a battery can go through before its performance degrades substantially. Therefore, we assumed that once a battery has reached its cycle life it would be replaced.
- The *lifetime* has a similar purpose to the cycle life, in that it represents the number of years for which a battery's performance is warranted. Although a battery may last beyond its lifetime, its performance will be degraded. Therefore, we assumed that once a battery has reached its lifetime it would be replaced.
- The *round-trip efficiency* is the percentage of energy a battery releases, relative to the energy provided. The round-trip efficiency is used in the modelling to represent loss of energy of ES.

4 Energy storage cost trajectories

This section presents the cost projections of batteries, inverters, installation and rooftop PV. It does not present the whole system costs, because those costs depend on the actual ESS configuration (i.e. the number of kWh of batteries and the number of kW of inverter), which in turn depends on the application.

4.1 Battery cost projections

The projected battery cost trajectories under each of the learning rate sensitivities are shown in Figure 3, Figure 4, Figure 5 and Figure 6 for advanced lead acid, Li-ion, zinc bromide and molten salt batteries, respectively. The *minimum trajectory* in each figure refers to the GALLM cost trajectories developed using the highest learning rate, the *base trajectories* refer to the GALLM cost trajectories developed using the medium learning rate and the *maximum trajectories* refer to the GALLM cost trajectories developed using the lowest learning rate. Table 2 shows the learning rates assumed.

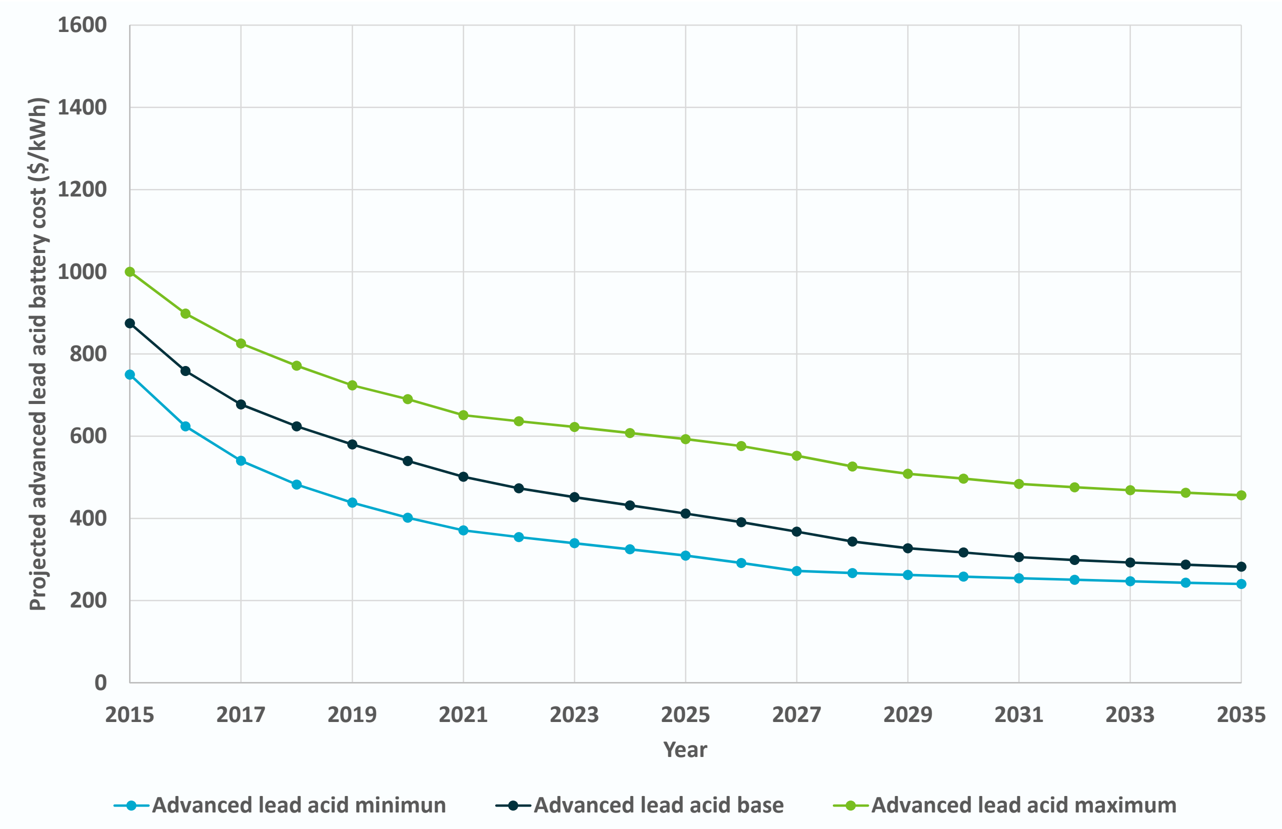

Figure 3: Projected capital cost trajectories of advanced lead acid batteries

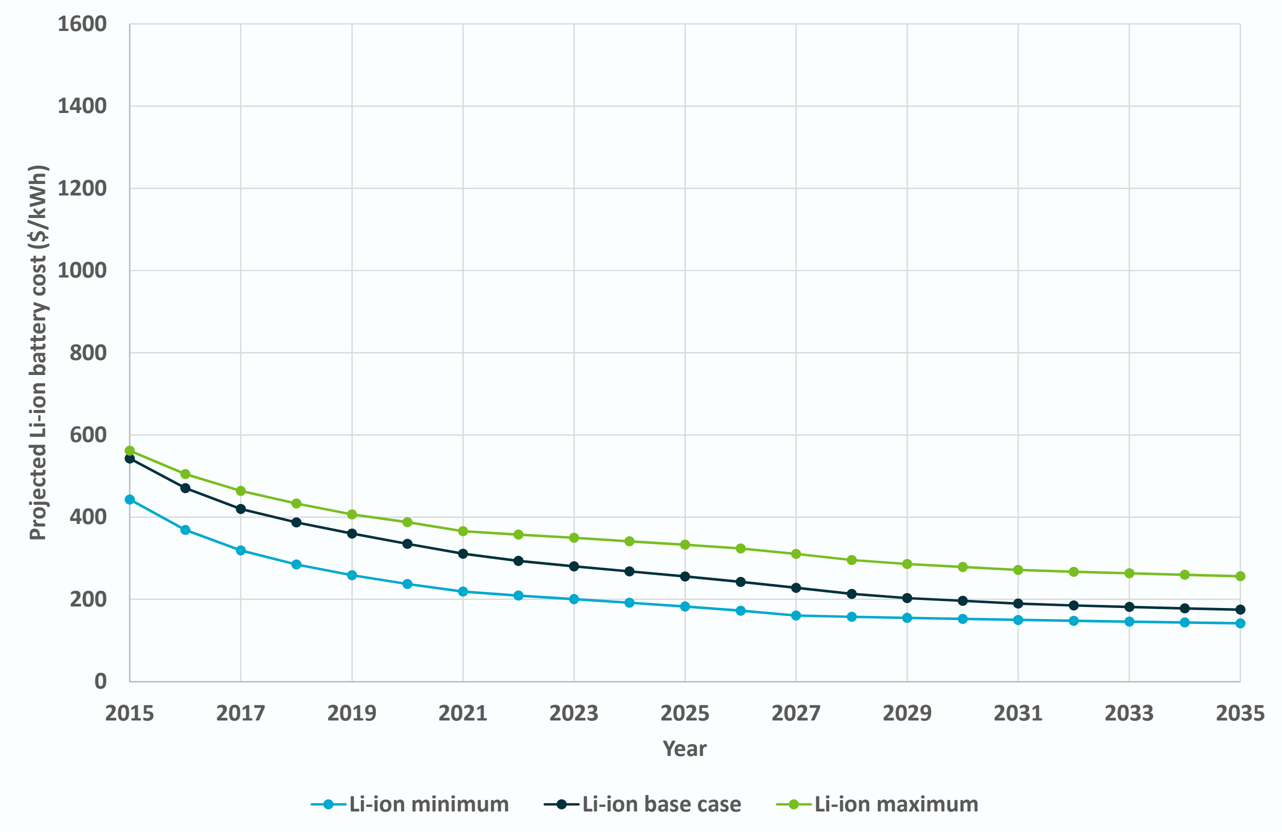

Figure 4: Projected capital cost trajectories of Li-ion batteries

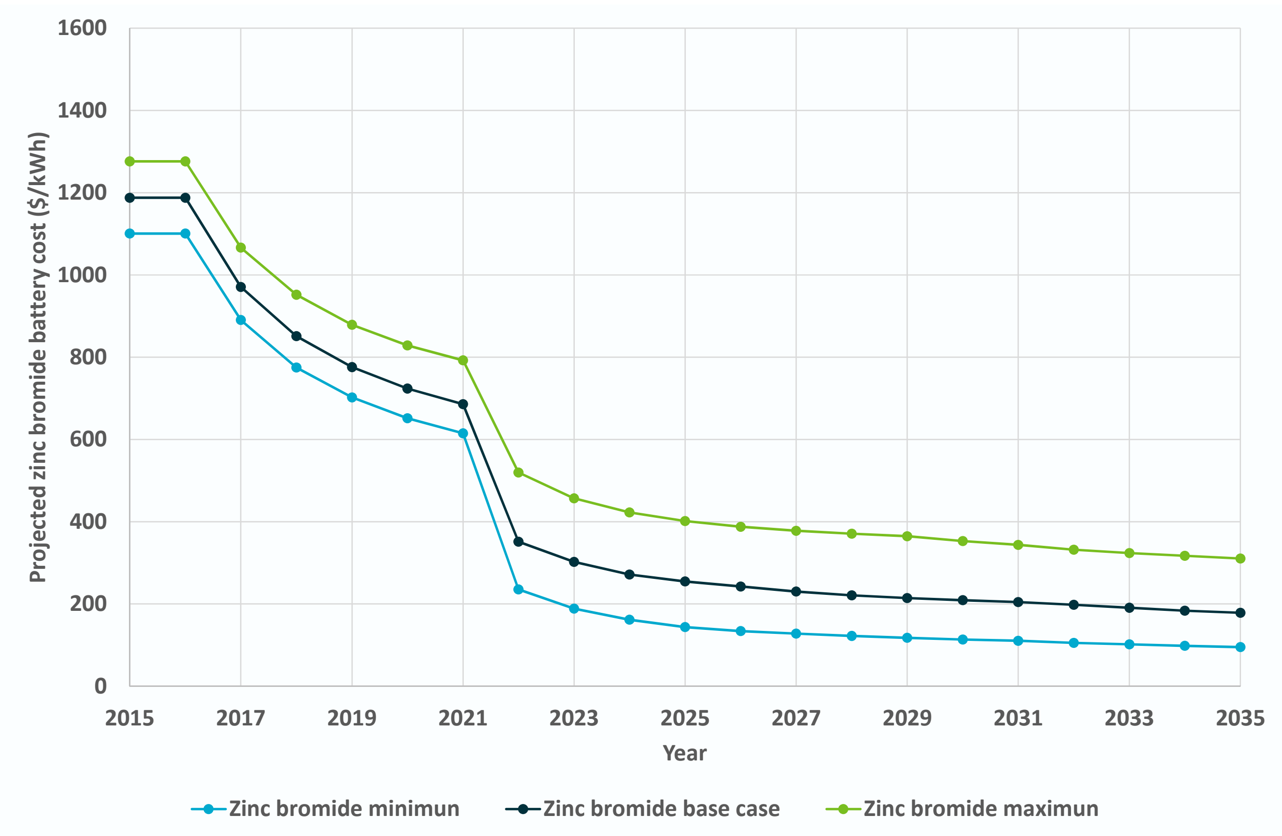

Figure 5: Projected capital cost trajectories of zinc bromide batteries

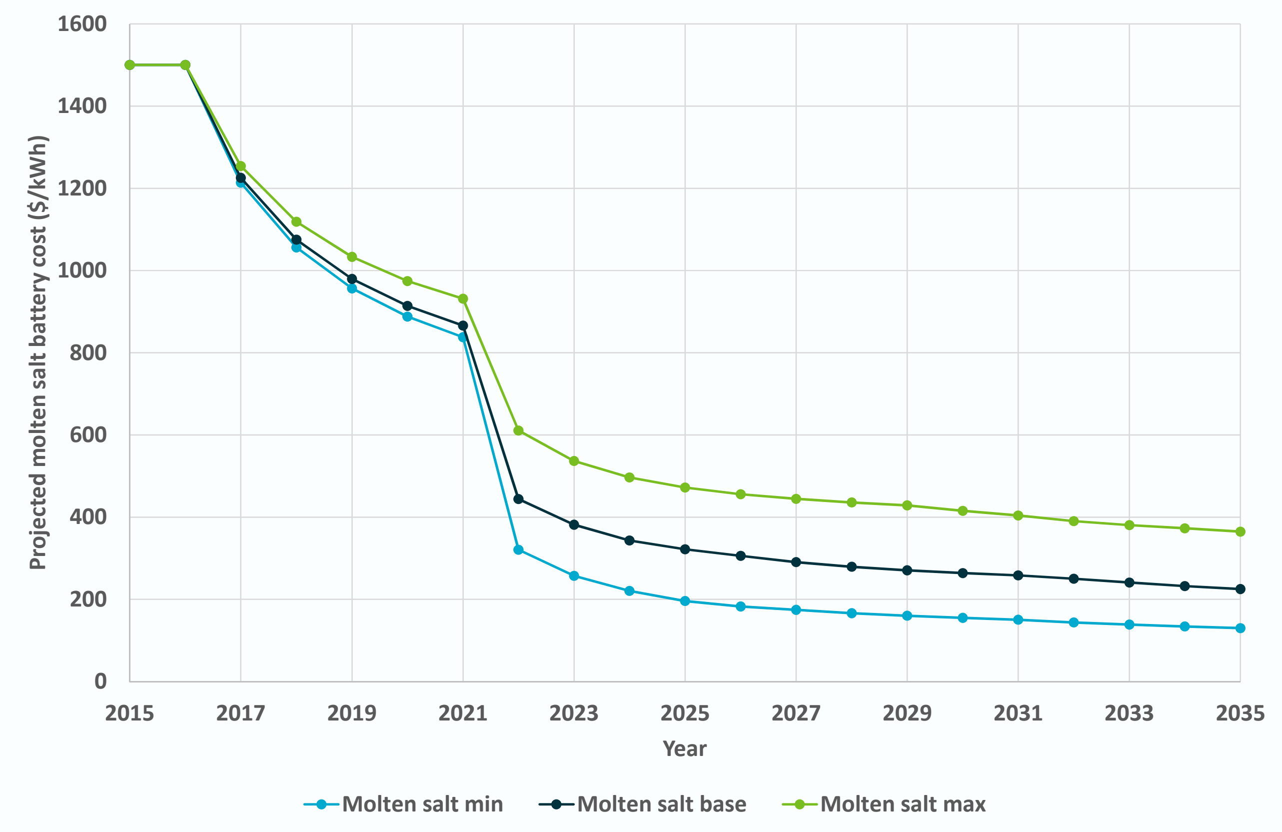

Figure 6: Projected capital cost trajectories of molten salt batteries

The shape of the trajectories differs markedly between the more mature technologies (Li-ion and advanced lead acid) and the less mature technologies (zinc bromide and molten salt). The less mature technologies have a higher learning rate, and therefore a steeper decline in capital cost after the year 2016, which then levels out in the year 2022. The decline from 2021 to 2022 is particularly steep. This reflects the fact that the initial cumulative installed capacity of these technologies is low; thus, when batteries are installed in the model, the cumulative capacity quickly builds up. This results in rapid cost reductions: 15% for every doubling of cumulative capacity. However, as more capacity is accumulated, even more capacity needs to be installed for further cost reductions to occur. Eventually, all low-cost opportunities for these batteries to be installed in the model have been used, and the learning saturates. After this point, the cost reduces slowly, and the technology could be considered mature.

The more mature technologies have a much flatter cost trajectory. The costs are already low and there is more cumulative capacity to begin with, because there is also the inclusion of EV battery capacity; when coupled with the lower learning rate (9%), this means that a lot more capacity needs to be installed in order for significant cost reductions to occur. A lot of capacity is installed, however, and the learning has saturated by 2025. The general difference in the slope of all trajectories between Figure 3 and Figure 4 is due to the difference in initial capital costs; although both technologies share the same annual percentage cost reductions per sensitivity case, a higher initial capital cost will result in a bigger annual change in capital cost.

The sensitivity of the model to the learning rate can also be seen in these figures. Changing the learning rate by ±25% alters the cost trajectory more for the less mature technologies than for the mature ones. In fact, the annual percentage cost reductions are similar for all of the more mature technology trajectories; the only difference is the starting point. In this case, the model is not sensitive to the learning rate for the more mature batteries but it is sensitive to the rate for the less mature batteries.

The installed global capacity of all technologies in GALLM is shown in Figure 7 for the case where the batteries have the base-case learning rate.

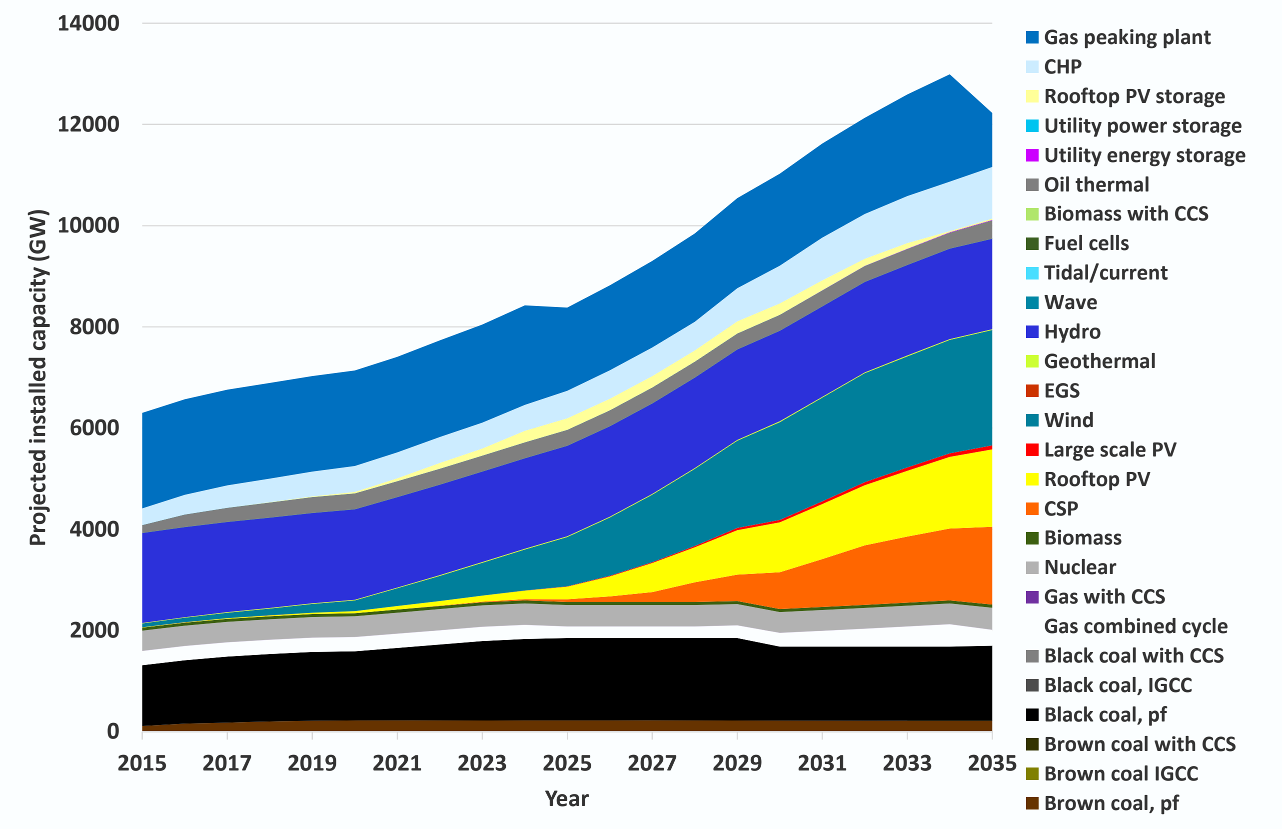

Figure 7: Projected installed capacity of all technologies in GALLM under the base learning rate scenario for batteries

CCS, carbon capture and storage; CHP, combined heat and power; CSP, concentrating solar power; EGS, enhanced geothermal systems; GALLM, Global And Local Learning Model; IGCC, integrated gasification combined cycle; pf, pulverised fuel; PV, photovoltaic

Table 6 shows the projected installed capacity in 2025 of technologies related to ES in GALLM. Of the ES technologies in Table 6, rooftop PV storage has more installations by 2025 than do utility energy storage and utility power storage. This means that the installed capacity of competing technologies (e.g. gas peaking plant, hydro and CSP) is sufficient to meet peak energy and peak capacity demand. Rooftop PV alone dominates the PV market in GALLM; therefore, the incentives, performance and cost of storage with PV are not sufficient to ensure uptake of this technology globally. Li-ion batteries are used in the rooftop PV storage market, so the uptake of rooftop PV batteries is driving cost reductions in Li-ion batteries. Zinc bromide batteries are used in the utility peak energy demand market; thus, this application is driving cost reductions of this battery type. By 2035, 25 GWh of zinc bromide batteries are projected to have been installed.

Table 6: Projected installed capacity of selected technologies by 2025

Technology	Installed capacity by 2035
Rooftop PV storage	230 GWh
Utility power storage	0 GWh
Utility energy storage	0.01 GWh
Rooftop PV	250 GW
Gas peaking plant	1650 GW
CSP	50 GW
Hydro	1790 GW

CSP, concentrating solar power; PV, photovoltaic

4.2 Inverter and installation cost trajectories

The inverter cost trajectories are shown in Figure 8. Inverters are a mature technology and they have a high cumulative capacity at the start of the modelling run because of their application in rooftop PV systems. Therefore, as with Li-ion and advanced lead acid batteries, they require large increases in installations in order for significant cost reductions to occur. In the base case, by 2035 the capital cost has reduced by $300/kW, which is a reduction to about two-thirds of the initial cost.

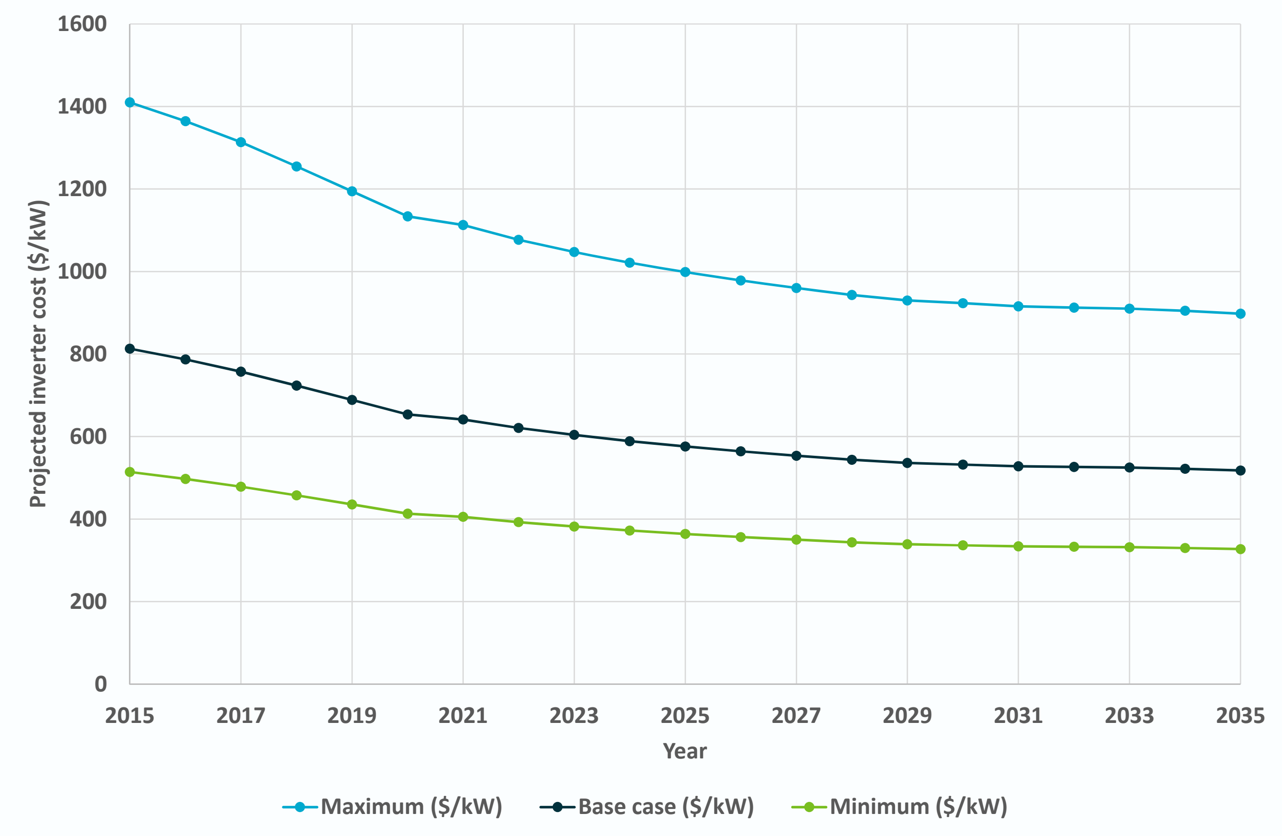

Figure 8: Projected inverter cost trajectories

As the installation of batteries can be undertaken by a licensed electrician, it has been suggested that they are no more difficult to install than any other electrical appliance. Therefore, it has been assumed that the cost of installation only falls by a constant 0.05% per year. This is the same as other mature technologies in GALLM.

4.3 Rooftop PV cost projections

The projected costs of rooftop PV are shown in Figure 9. These costs are for a standalone system with inverter replacement, without storage and without any government incentives. The range is based on the range of prices available in the market today for rooftop-size systems [40]. The minimum, maximum and base cases refer to the battery learning rate cases shown in Table 2, where the PV cost trajectories were determined from these scenarios. The PV learning rate was the same in each scenario. Therefore, the minimum trajectory in Figure 9 was generated from the same model run as the minimum battery trajectories.

The results show a slight increase in PV prices in 2016, which then reduces (the rate of reduction depends on the case). The increase in price is due to projected extremely high levels of PV installations, where supply cannot keep up with demand.

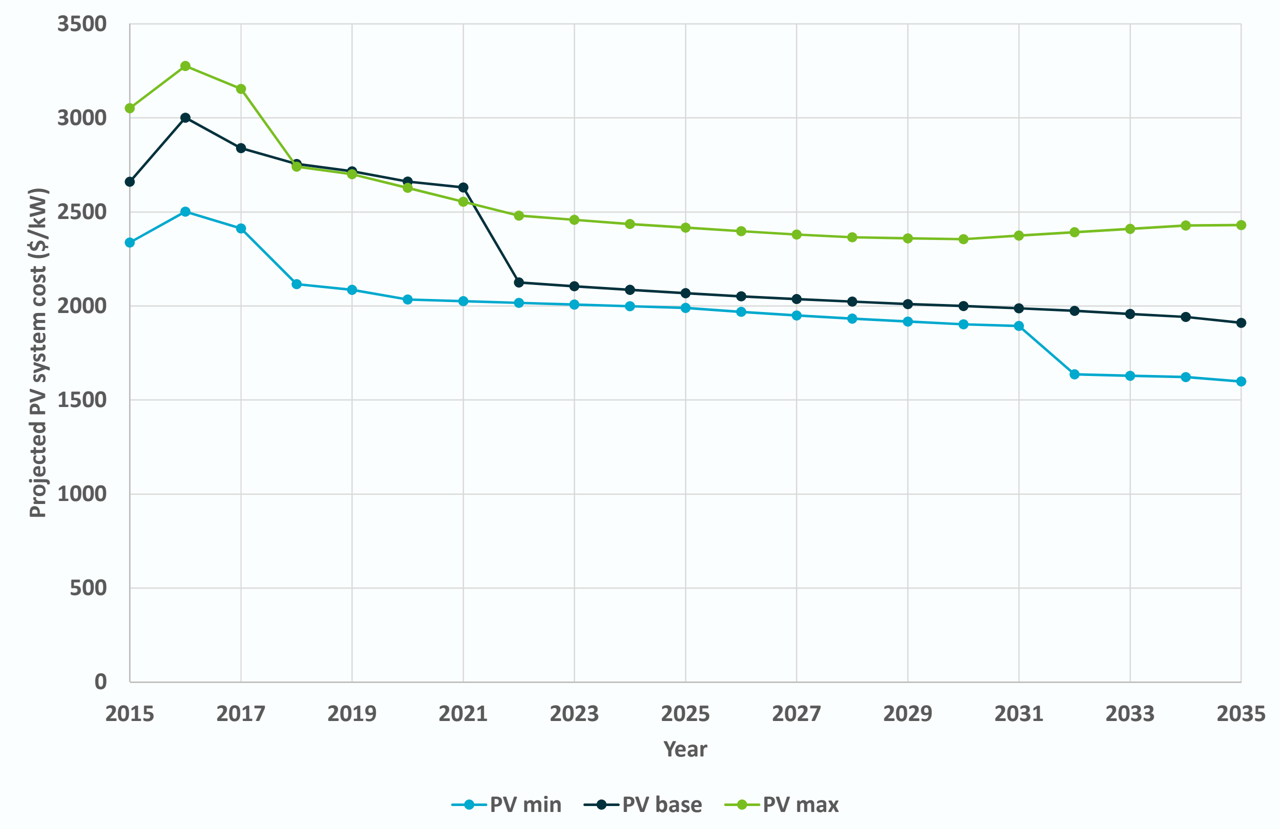

Figure 9: Projected rooftop PV system cost trajectories

max, maximum; min, minimum; PV, photovoltaic

4.4 Comparison with other cost projections

There has been much hype in the media about batteries, and various institutions have publicised future projections of battery costs (Li-ion in particular). The Rocky Mountain Institute (RMI) in the US [41] has compiled Li-ion battery cost projections; these are compared with the cost projections from this study and an average of all projections in Figure 10. The CSIRO minimum and maximum cost projections are shown as a range, to make comparison easier. Bloomberg New Energy Finance (BNEF) and Navigant both start with higher costs than the CSIRO minimum trajectory, but their costs then fall further, reaching about $137/kWh by 2035. At that point, the difference between BNEF/Navigant and the CSIRO minimum is only $5/kWh. The US Energy Information Administration (EIA) has consistently higher costs across the whole timeframe examined. The CSIRO base case is lower than the average by $29/kWh by 2035.

The CSIRO costs are neither the highest nor the lowest, but fall within the range of other studies. The advantage of the CSIRO costs is that the projections are based on a consistent, robust, transparent and peer-reviewed methodology. In contrast, the methodology and assumptions used to arrive at other projections is generally not disclosed in sufficient detail to be understood.

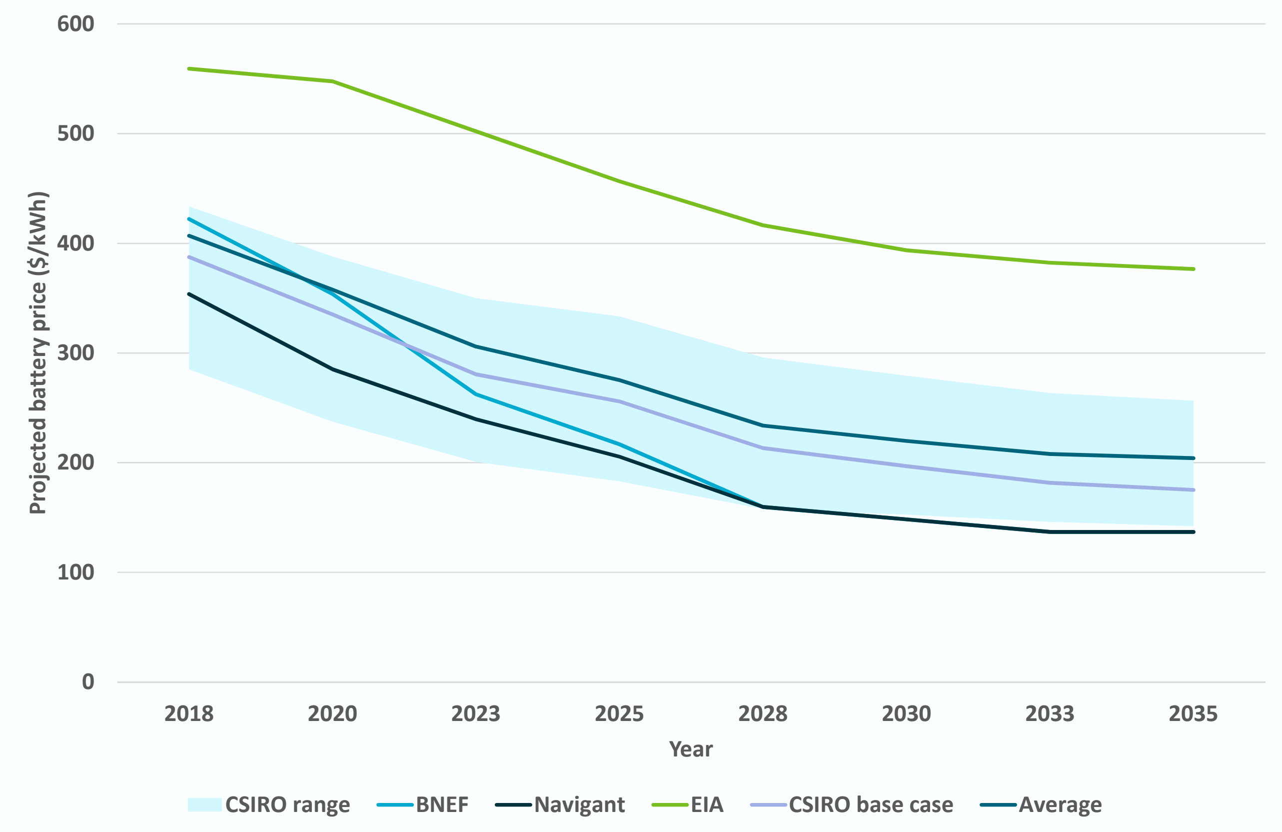

Figure 10: Comparison of Li-ion battery cost projections

BNEF, Bloomberg New Energy Finance; CSIRO, Commonwealth Scientific and Industrial Research Organisation; EIA, Energy Information Administration; Li, lithium; RMI, Rocky Mountain Institute

Source: Non-CSIRO data from RMI [41]

Part II Potential uptake and impacts

5 Economic viability of storage

This section analyses the economic viability of storage when considered from the point of view of an investor, whether that be a network business, commercial or residential customer, or vehicle owner. This is important because we assume that battery adoption will only take place if there is a benefit to an investor, whatever the broader benefits or costs to other parties.

This section:

- explores the costs associated with the design and operation of electrical networks to assess the economic viability of ES for distribution or transmission operators, or both
- evaluates the economic viability of on-site battery storage for commercial customers for different tariff structures and end-use cases
- provides a case study of how storage can reduce the cost of a new connection for an industrial-sized customer
- analyses the economic viability of storage for residential customers for different application cases
- analyses the economic viability of using batteries to participate in the NEM when competing against gas peaking plant to provide similar services
- examines whether EVs may become an economically viable vehicle choice and, if so, under what circumstances.

5.1 Distribution and transmission networks

Various factors affect the economic viability of ES for power system operators responsible for the design, operation and maintenance of electrical networks that supply the essential service of electricity to homes, businesses and industry. These factors include:

- annual consumption and electricity demand profiles in the distribution or transmission networks
- generation profiles of grid-connected renewables (e.g. solar PV)
- capacity limits and reliability indices as prescribed in the licence conditions for electrical operators
- the upfront and ongoing costs of ESS
- expected life and operational performance of ESS.

This section considers costs associated with the design and operation of electrical networks to assess the economic viability of ES for distribution or transmission operators.

5.1.1 Background

In the transmission of electricity, the role of the network is to deliver electrical energy from large-scale generators to a bulk supply point. The subtransmission network then delivers this electricity to zone substations and large industrial customers. The distribution network subsequently delivers this electricity directly to the end user via a point of common coupling. In more detail, distribution 'feeders' operate at medium voltages (MV), for example, at a nominal 11 kV. From these feeders, MV loads are supplied, or small distribution transformers step the voltage down to a more practical low nominal voltage from which a number of low voltage (LV) loads are supplied, as shown in Figure 11.

Australia has thousands of kilometres of MV distribution network. Most of the distribution feeders consist of overhead lines, since overhead construction costs are significantly less then underground ones [42]. Moreover, in the Australian context, it is typical for rural distribution networks to incorporate single wire earth return (SWER) feeders. SWER systems use the earth as a return path for the current drawn by loads, and are typically cheaper than more traditional feeder topologies of similar capacity.

Distribution networks typically incorporate active network components such as on-load tap changing transformers, voltage-regulating transformers and shunt capacitors. Transformers that supply distribution feeders (e.g. 33 kV/11 kV transformers) are often fitted with voltage regulation capabilities, such as control schemes that operate on-load tap changers (OLTC). Transformers that step down MV to LV typically have fixed tap setting that can be changed by a distribution network service provider (DNSP) if required. Rural MV distribution feeders often incorporate one or more voltage-regulating transformers along a feeder to ensure that the nominal LV delivered to customers is within the +10% to –6% tolerance required [43, 44]. Moreover, shunt capacitors on MV feeders or within zone substations are often fitted with controls to provide voltage regulation or power factor correction (or both), in order to improve the quality of the electricity supplied to customers.

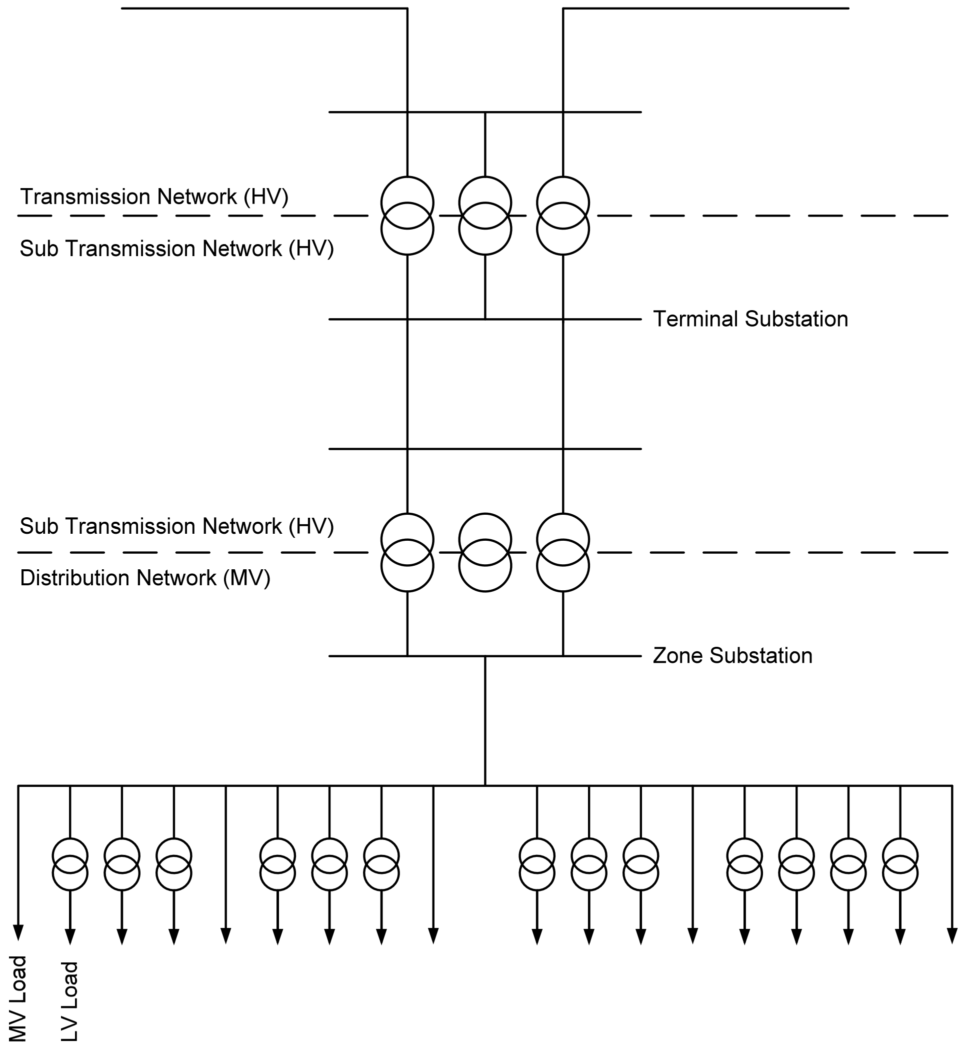

Figure 11: Indicative single-line diagram of the electrical network as a whole, showing where MV and LV distribution networks are placed

HV, high voltage; LV, low voltage; MV medium voltage

Note that the distribution networks effectively begin at the secondary side of zone substation transformers and end at MV and LV loads.

DNSPs are responsible for design, operation and maintenance of distribution networks that supply the essential service of electricity to homes, businesses and industry. The reliability of a distribution network is measured by a number of indices [45, 46]. These indices are prescribed in the licence conditions for electricity distributors [47, 48] and they comprise:

- the average minutes off supply per customer due to planned and unplanned outages (the system average interruption duration index, SAIDI)
- the average number of unplanned interruptions per customer, excluding momentary interruptions (the system average interruption frequency index, SAIFI).

These indices are used to calculate penalty payments owing to customers when DNSPs fail to meet guaranteed service levels set by the Australian Energy Regulator [47].

In what follows we define LV phase-to-neutral by a nominal 230 V, with a tolerance of +10% to –6%, as defined in the Australian Standard AS 60038 [43]. MV are defined by a range of phase-to-phase values, from a nominal 1 kV to a nominal 22 kV. Any phase-to-phase voltage from a nominal

33 kV up to 132 kV is recognised as a subtransmission voltage. Voltages above and including 220 kV phase-to-phase are recognised as a nominal transmission voltage.

5.1.2 What are grid infrastructure costs?

To meet guaranteed services levels set by the Australian Energy Regulator [47], a DNSP might seek to use battery storage. For example, if peak demand in a distribution grid is expected to exceed network capacity, then battery storage may provide a cost-effective solution if the alternative is to increase the capacity of the distribution grid. Before considering the potential of battery storage to reduce capital costs that would otherwise be incurred by electric power system operators, we first define some generic costs associated with transmission and distribution infrastructure. A number of sources have been identified that provide estimates of the costs associated with installing and connecting distribution or transmission infrastructure to the electricity grid in Australia [49–63]. In what follows we have collated and adjusted these estimates in order to estimate present-day costs for installing and connecting such infrastructure. The generic estimates presented in what follows have an uncertainty of approximately ±50%. Table 7 shows the assumed overhead and underground construction costs to a feeder or substation.

Table 7: Assumed overhead and underground construction and connection costs (to a feeder or substation) for the period 2015–2020, by voltage

Voltage	UG construction costs	OH construction cost	Connection costs
415 V	$0.6 m/km	$0.010 m/km	$450–$40,000
11 kV	$0.7 m/km	$0.014 m/km	$0.1 m–$1 m (connection in a substation or an OH/UG teed[a] connection, including protection and control infrastructure)
66 kV	$5 m/km	$0.55 m/km	$6 m (connection in a substation or an OH teed connection, including protection and control infrastructure)
132 kV	$6 m/km	$0.75 m/km	$10 m (connection in a substation or an OH teed connection, including protection and control infrastructure)
220 kV	10 m/km	$1 m/km	$20 m (connection in a substation or an OH teed connection, including protection and control infrastructure)
330 kV	15 m/km	$1.8 m/km	$30 m (connection in a substation or an OH teed connection, including protection and control infrastructure)

OH, overhead; UG, underground

Costs are in AUD, where 'm' denotes a factor of $1 000 000

[a] A teed connection is one that is parallel to an existing UG or OH line.

5.1.3 What are grid capacity limits?

When infrastructure in the electricity grid reaches a capacity limit, distributors or transmission operators typically incur costs associated with re-enforcing the electricity grid. Capacity limits are often described in terms of thermal limits (with current or power ratings) or voltage limits, for particular network configurations [48].

Because overhead conductors are exposed to the elements, differences in ambient air temperature and wind speed affect the current carrying capacity of a conductor. To reflect temperature extremes, two ambient air temperatures are often assumed: summer noon, 35 °C, and winter night, 10 °C. These operating conditions, together with an assumed wind speed, are used to derive maximum and minimum thermal capabilities for overhead lines on a summer day and a winter night, respectively [64]. To determine the maximum steady-state current carrying capacity of overhead conductors at specific ambient temperature conditions, the installation characteristics such as height and span between supports are also required, to ensure that a conductor has adequate safety and structural clearances [65, 66].

The design and construction of underground cables varies significantly. For example, single-core and three-core cables are available with aluminium or copper conducting materials, which are constructed for various fault levels [67]. Underground cables are often directly buried (with or without thermal backfill); they may also be placed in conduits. The method in which specific types of underground cables are buried, together with preceding load variations, informs calculations that determine the maximum current carrying capacity of specific underground cables, which is described in more detail in IEC standards 60853-1 and 60287-1-1 [68, 69].

The current carrying capacity of transformers connected to the electrical grid depends on preceding load variations as well as the cooling systems implemented [70]. In determining the current carrying capacity of distribution transformers connected to MV feeders, daily load profiles (Figure 12) are often considered by distribution operators. Figure 12 illustrates eight normalised daily load cycles commonly seen at distribution transformers. The load cycle or cycles illustrate:

- an industrial or commercial load cycle (top left)
- mixed industrial or residential load cycles (bottom left to middle)
- domestic load cycles with or without water heating (top middle to right)
- a continuous load cycle (bottom right).

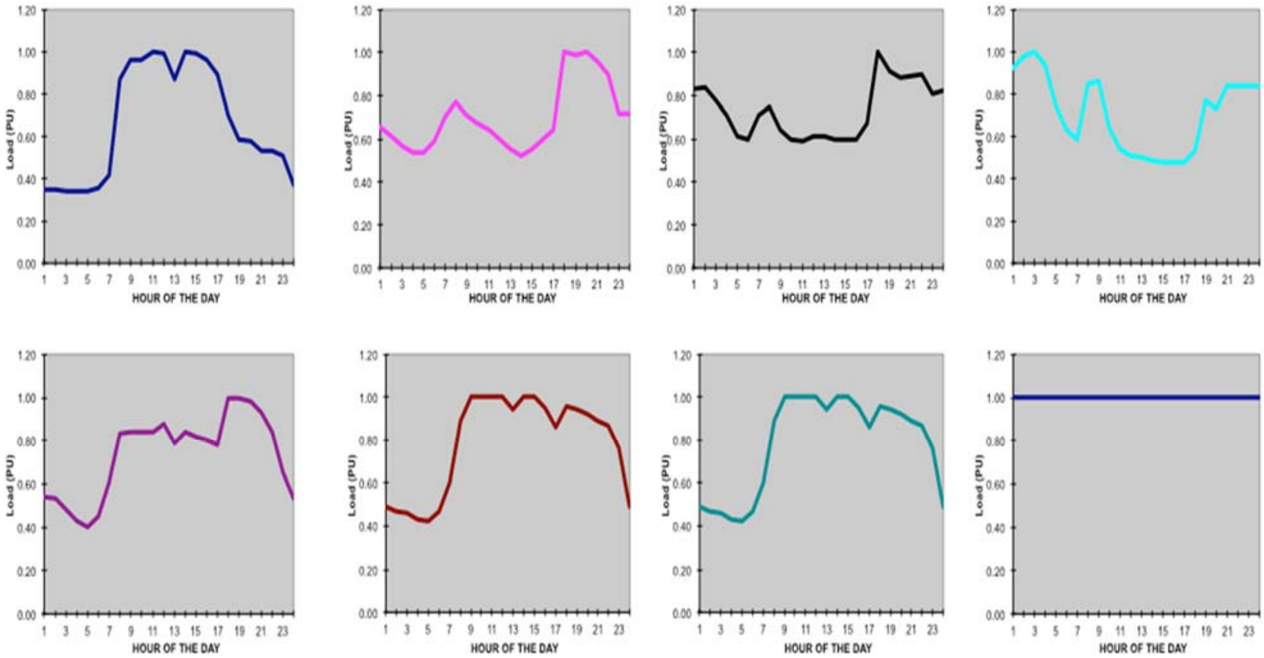

Figure 12: Typical daily load profiles as seen by a distribution transformer

The x-axis of each graph denotes the hours in a day, and the y-axis denotes the normalised load
Source: Personal communication with Ausgrid

In Figure 12**,** the continuous load cycle has a continuous rating; however, the remaining load cycles in the figure permit a higher cyclic rating to be applied to a transformer. That is, a daily load cycle that leads to a transformer cooling for a period of time results in a higher short-term (cyclic) rating.

In Table 8, continuous ratings are represented by a factor of 1; the table also presents higher cyclic rating factors that are often applied to distribution transformers. For example, if a distribution transformer has a continuous rating of 400 kVA, then a cyclic rating of 588 kVA may be applied to the transformer in cases where the daily load cycle is defined by the domestic case presented in Figure 12**.**

Table 8: Indicative cyclic rating factors for a single distribution transformer substation

Load cycle	Cyclic rating factor for a single transformer	Description
Industrial	1.14	Industrial Mixed predominantly industrial Commercial
Mixed	1.38	Mixed predominantly domestic
Domestic	1.47	Domestic little hot water load Domestic much hot water load
Continuous	1	Mixed predominantly domestic

Source: [71]

Residential load cycles as seen by distribution transformers may also vary from summer to winter. Figure 13(a), which was generated from residential data provided in [71], shows that in summer the residential load profile increases throughout the day, peaking in the early evening. Figure 13(b) shows that in winter there is a morning and an evening peak. Consequently, residential cyclic rating factors applied in the electrical grid potentially vary from summer to winter.

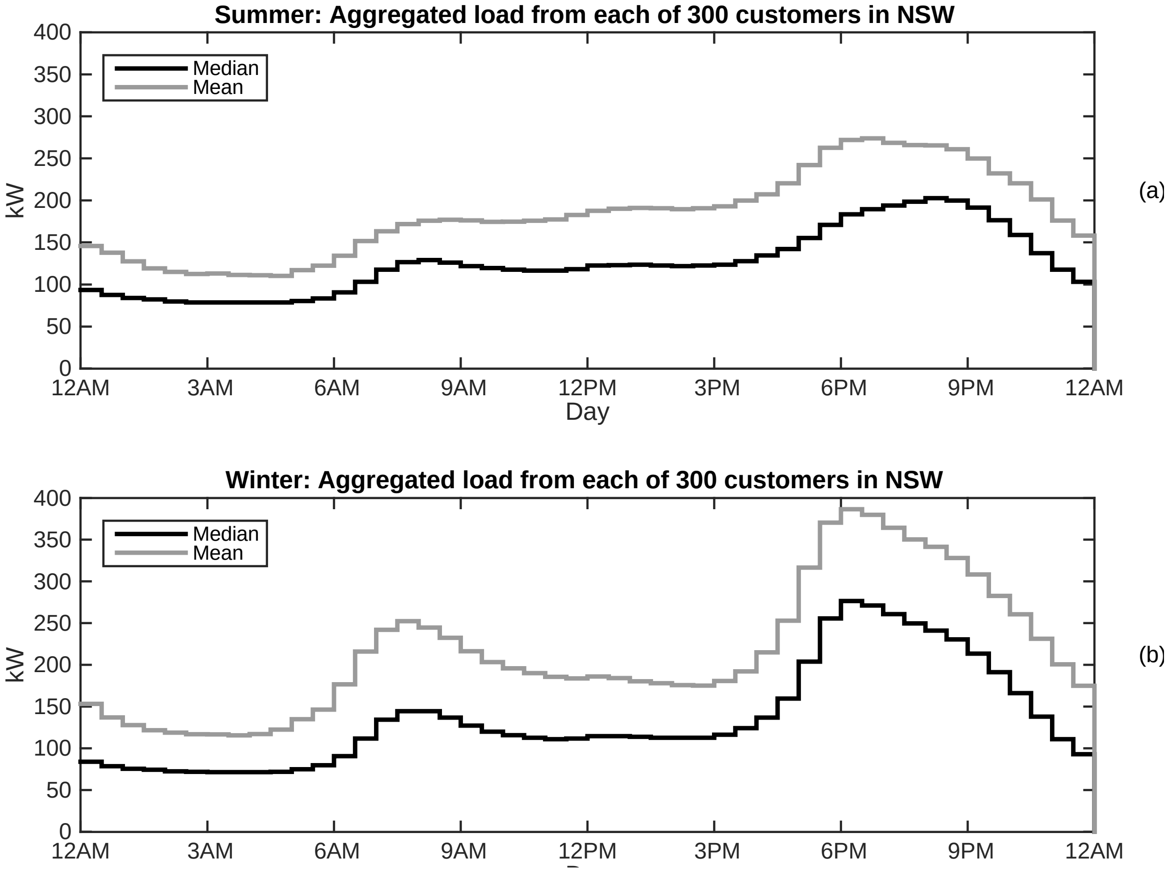

Figure 13: Aggregate residential load from 300 customers in New South Wales

NSW, New South Wales

Sources: [71, 72]

5.1.4 How often do peak loads occur?

Peak loads on MV/LV distribution transformers may or may not align with peak loads in the upstream feeder, zone substation, and the transmission or subtransmission network. A domestic load cycle at an MV/LV transformer potentially leads to a peak load driven by high ambient temperatures on weekdays or weekends. In the upstream feeder, a mixed commercial–domestic load cycle potentially leads to a peak load driven by high ambient temperatures on weekdays rather than weekends. An example is given in Figure 14, wherein residential loads from 300 customers in New South Wales, Australia, are aggregated over the 3-year period from July 2010 to June 2013 [71, 72]. Figure 14(a) shows a single day where the aggregate residential load exceeds 800 kW. This peak load occurred on Sunday 6 February 2011, during a heatwave in Sydney [73]. In contrast, during 2011, the peak demand across New South Wales occurred on Tuesday 1 February 2011 [74]. Peak loads that lead to capacity constraints within the distribution network are investigated by utilities on a case-by-case basis.

The frequency of peak load events varies at different locations in the distribution network. However, ambient temperature is typically a good indication of the potential for a peak load event. In particular, a very low ambient temperature or a very high ambient temperature on a weekday outside of a school holiday or a public holiday commonly coincides with peak load events in parts of the distribution or transmission network. Thus, Figure 14(b) shows that the aggregate residential load exceeds 400 kW approximately 2% of the time, and Figure 14(a) shows that the aggregate residential load exceeds 400 kW in both summer and winter. Cases where the load is zero in Figure 14 correspond to changes in daylight saving time, rather than events where no load is consumed [72].

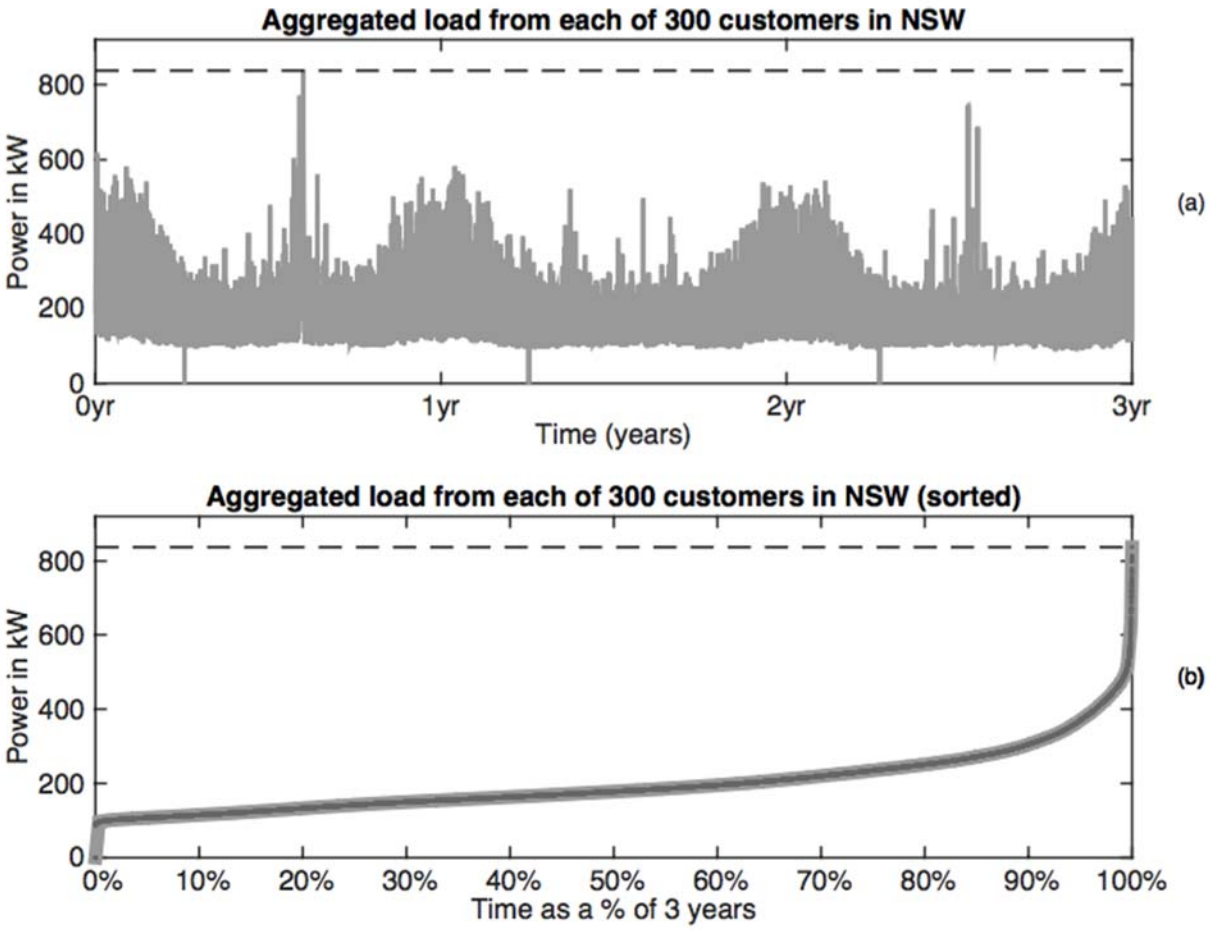

Figure 14: Aggregate residential load from 300 customers in New South Wales from 1 July 2010 to 30 June 2013

NSW, New South Wales
Sources: [71, 72]

The duration of a peak load event – together with ambient or conductor or transformer winding temperatures – assists in calculations of the throughput capacity of infrastructure in the electricity grid. Peak loads that occur in summer rather than winter, over a number of hours, are more likely to lead to capacity constraints requiring remediation in the electricity grid.

5.1.5 What is the effect of significant reverse power flow from residential PV?

Traditionally, distribution networks and their voltage control and protection systems have been designed and constructed in a radial fashion, to facilitate unidirectional power flow. The primary purpose of network protection equipment is to disconnect faulty network components in order to prevent damage to plant and ensure safety to the public and network personnel. In cases with light feeder loading or high distributed generation (DG) penetration, the distribution network may need to be able to accommodate reversed (negative) power flow, which could interfere with traditional voltage and protection system designs [75]. This is particularly important in cases where MV protection systems have been designed with directional relays that may now see power flow in the opposite direction [76, 77].

Figure 15 presents aggregate residential demand from 300 customers located in New South Wales, generated from data proved by the distributor Ausgrid [71]. If these 300 customers were located in close proximity to each other, we would see significant reverse power flow in the distribution grid, as in Figure 15 (a). Figure 15 (b) shows that this reverse power flow would occur about 20% of the time. The reverse power flow would lead to investigation of the effectiveness of existing voltage control protection schemes, with replacement schemes potentially leading to significant costs for an electrical distributor [78].

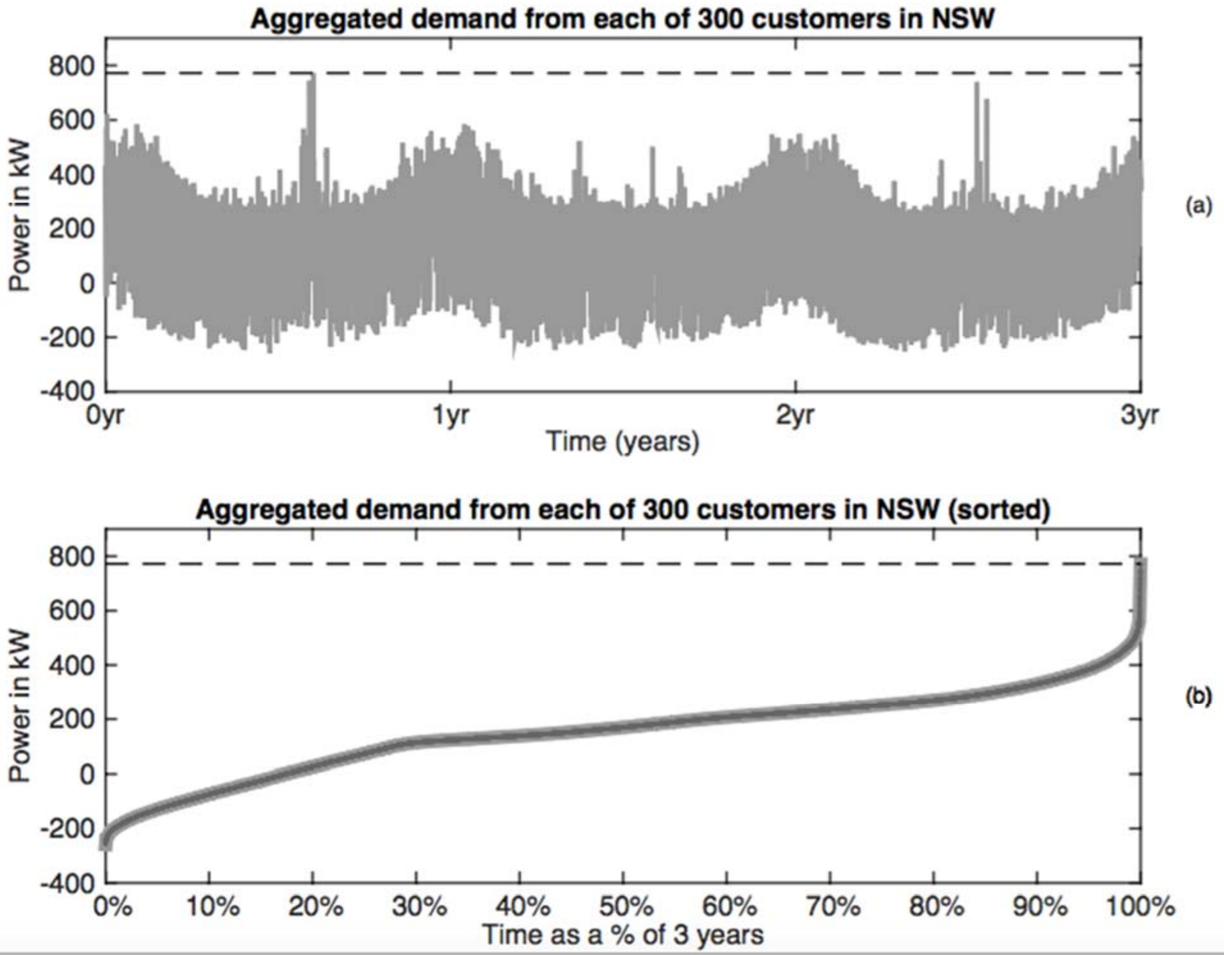

Figure 15: Aggregate residential demand (load minus PV generation) from 1 July 2010 to 30 June 2013 for 300 customers in New South Wales

NSW, New South Wales; PV, photovoltaic

Sources: [71, 72]

5.1.6 Case study: batteries and network cost reduction

The introduction of high DG penetrations together with battery storage brings opportunities to implement more adaptive design techniques (e.g. islanding) to potentially further improve the reliability performance of distribution networks (cf. Section 5.1.1). Moreover, battery storage co-located with DG potentially provides opportunities to improve the quality of the voltage supplied to customers [72, 75, 79–81], together with reducing demand that leads to capacity constraints within the electricity grid (see Sections 5.1.3, 5.1.4) [82].

Charging battery storage co-located with DG when significant reverse power flow presents in the electrical grid may also lead to cost savings for power system operators. For example, existing voltage control or protection schemes may continue to operate as traditionally designed when excess generation from rooftop solar PV is stored in a battery (see Section 5.1.5). In contrast, end-of-line voltage measurements and associated communication infrastructure may be required by distributors when significant reverse power flow is present in the distribution grid in order to detect and mitigate either of the following:

- voltages rise outside Australian Standard AS 60038 [43]
- faults at the end of distribution feeders [78].

DNSPs will typically incur costs associated with these additional measurements, communication infrastructure, and associated control and protection schemes.

Discharging battery storage to reduce peaks in electrical demand across the grid may defer capital expenditure in the distribution or transmission grid. In cases where residential-scale battery storage is charged and discharged in order to smooth load cycle peaks and valleys across the state, steady-state ratings applied in the distribution grid may be reduced from a cyclic to a continuous rating (see Section 5.1.3). Case-by-case assessments of a distribution grid would therefore be required to determine the impact of potential rating reductions. Moreover, it is currently not possible to proscribe the optimal load profile for a distribution grid, because factors such as temperature, wind speed, overhead line construction (including high and span between conductors), cable arrangements (including thermal backfill properties), and transformer top oil temperatures are required to determine the existing capacity of a distribution grid at a point in time (as discussed in Section 5.1.3) [83].

In [82], two approaches to charging and discharging residential battery storage co-located with solar PV are proposed. Each approach seeks to limit peak demand and significant reverse power flow across a point (e.g. a zone substation) in the electricity power grid, in addition to enabling residential customers to accrue savings from battery charge or discharge schedules. Some of the results presented in [82] are considered below.

Figure 16 shows daily peaks and minimums in aggregate residential demand from 112 customers with a gross feed-in meter recording solar PV generation. Each customer is located in New South Wales, and was identified with the data obtained during the Smart Grid Smart City (SGSC) trial [84]. The figure shows 7 days in a year when residential peak demand exceeds 210 kW, a representative continuous rating for the purpose of this case study. It also shows 9 days in a year when reverse power flow exceeds 100 kW in magnitude, which potentially leads to voltage excursions outside power quality standards.

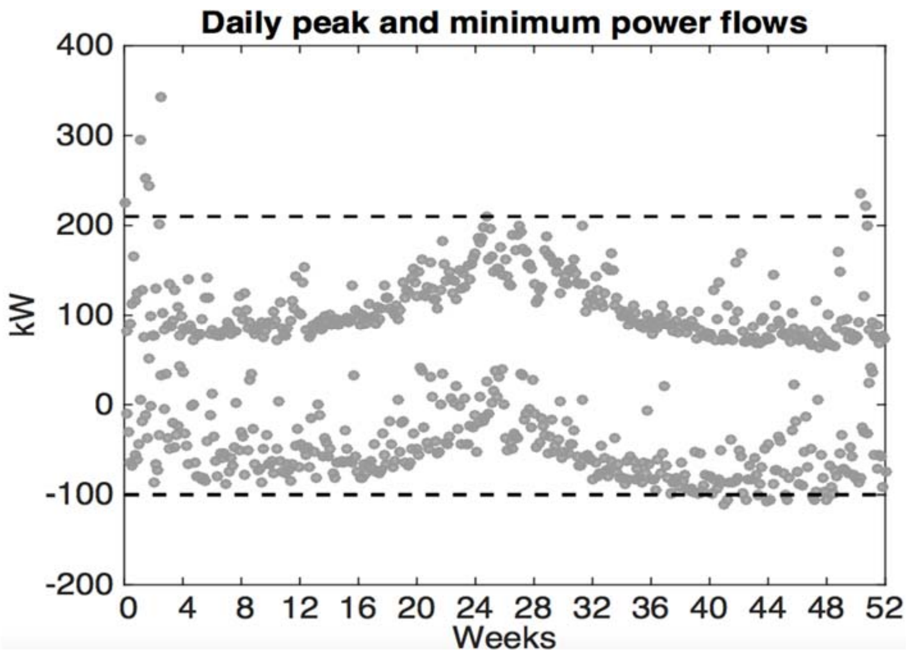

Figure 16: Aggregate residential demand for 112 customers in New South Wales, each with solar PV

PV, photovoltaic; SGSC, Smart Grid Smart City

Source: Residential load and solar PV generation data that was collected from 1 January 2012 to 31 December 2012 as part of the federally funded SGSC [82].

Two approaches to charging and discharging battery storage at each household are proposed [82]. The objective is to reduce the aggregate peak load to 210 kW together with limiting reverse power flow to 100 kW in magnitude (e.g. a reverse power flow constraint of –100 kW is considered), in addition to permitting customers to accrue operational savings as defined in [81, 82]. The results are shown in Figure 17, wherein Figure 17(a) presents the results of the localised approach and Figure 17(b) presents the results of the centralised approach.

In the localised approach, the energy management system of each household incorporates simple directives from the utility (in the form of three weights) together with time-of-use (TOU) pricing signals when determining day-ahead battery charge and discharge schedules. The three weights balance three objectives included in the residential energy management system: increase profits, reduce reverse power flow, and reduce peak load. Using the localised approach, Figure 17(a) shows just 2 days in the year where peak demand exceeds 210 kW, and on all days reverse power flow is less than 100 kW in magnitude. In the centralised approach, the utility directly specifies the charge and discharge schedule of each residential battery, which provides improved performance in peak load reduction across the entire year, as shown in Figure 17(b). Further, in the centralised approach, TOU pricing is included in the objective function, which leads to each customer accruing operational savings from the utility-prescribed battery schedule.

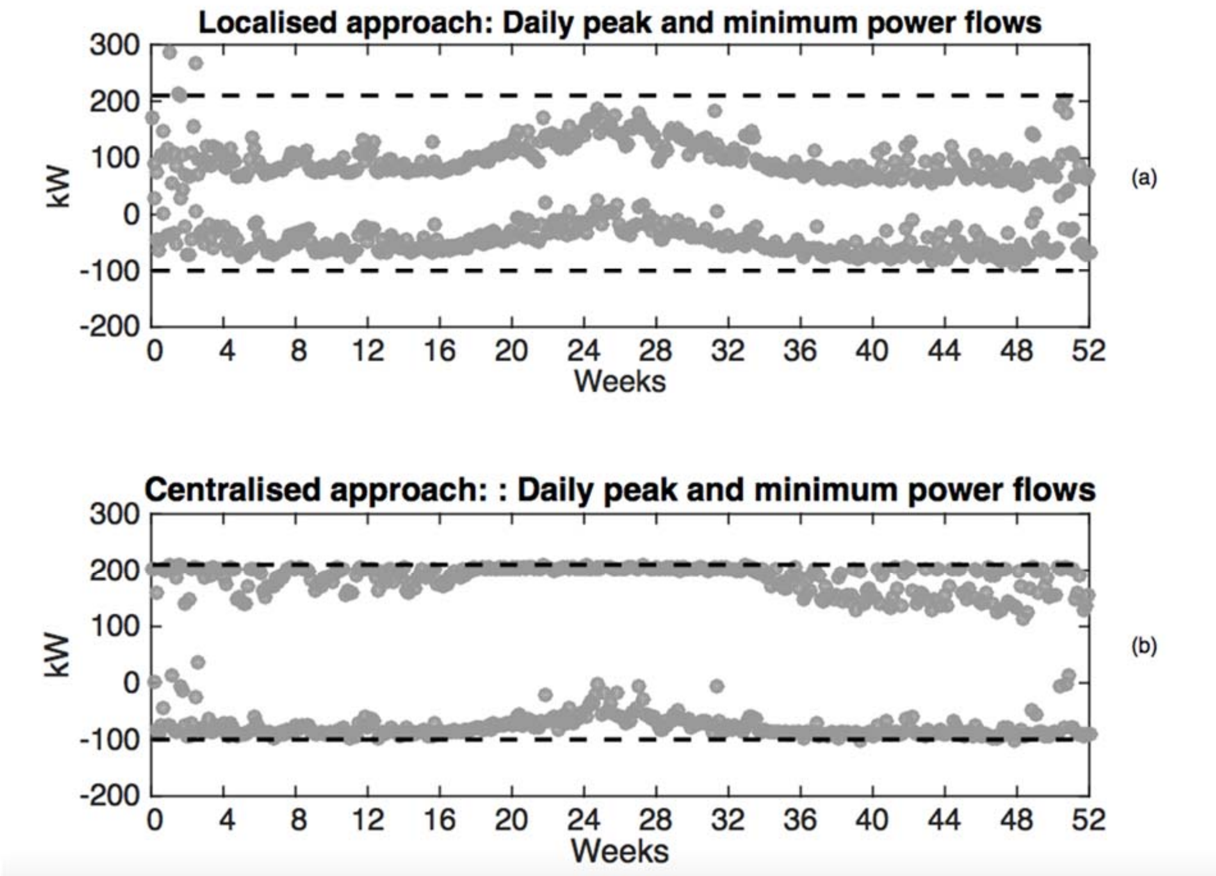

Figure 17: Aggregate residential demand for 112 customers in New South Wales when each customer installs a 10 kWh battery co-located with solar PV

PV, photovoltaic; SGSC, Smart Grid Smart City

Source: Residential load and solar PV generation data for each of the 112 customers was collected from 1 January 2012 to 31 December 2012 as part of the federally funded SGSC, and was used to generate this figure. The centralised and localised approach to scheduling the battery of each customer is described in more detail in [82].

A centralised approach to charging and discharging residential battery storage co-located with solar PV, similar to that proposed in [82], may potentially be used by distribution and transmission operators when there are capacity constraints in the electrical power grid. Such an approach demonstrates potential in deferring (indefinitely) costly investment in grid re-enforcements driven by peak demand or power quality excursions outside prescribed network limits (see Section 5.1.2). However, we cannot say whether the benefits of centrally controlling battery storage are always economically viable, given that the costs associated with increasing the electrical network capacity are case specific, as are the costs associated with alternative (demand management) approaches to peak demand reduction or power quality improvements, as outlined in [49–63].

5.1.7 Case study: batteries and demand management

This case study examines the viability of battery storage as a demand management strategy for transmission network operators. To better understand the cost-effectiveness of large-scale, grid-connected battery banks we consider three sites in close proximity to both transmission and subtransmission assets. We finally considered a scenario where a peak demand reduction of

25 MW is required in 2020 on the transmission network that passes through Eastern Creek, New South Wales.

For the purpose of this case study, we initially identified cities that are very close to large load centres, in addition to both transmission and subtransmission assets within the NEM [85–88]. We further restrict our search to cities that are not located in central business district (CBD) locations, where the cost of land associated with installing a very large battery bank together with underground construction costs (see Table 7) are presumed to be prohibitive. Figure 18 presents an overview of all cities considered, wherein three cities in close proximity to each other are further considered based on our selection criteria. Based on observations in Google Maps, the case study substation was located in one of the selected cities, namely Eastern Creek in New South Wales.

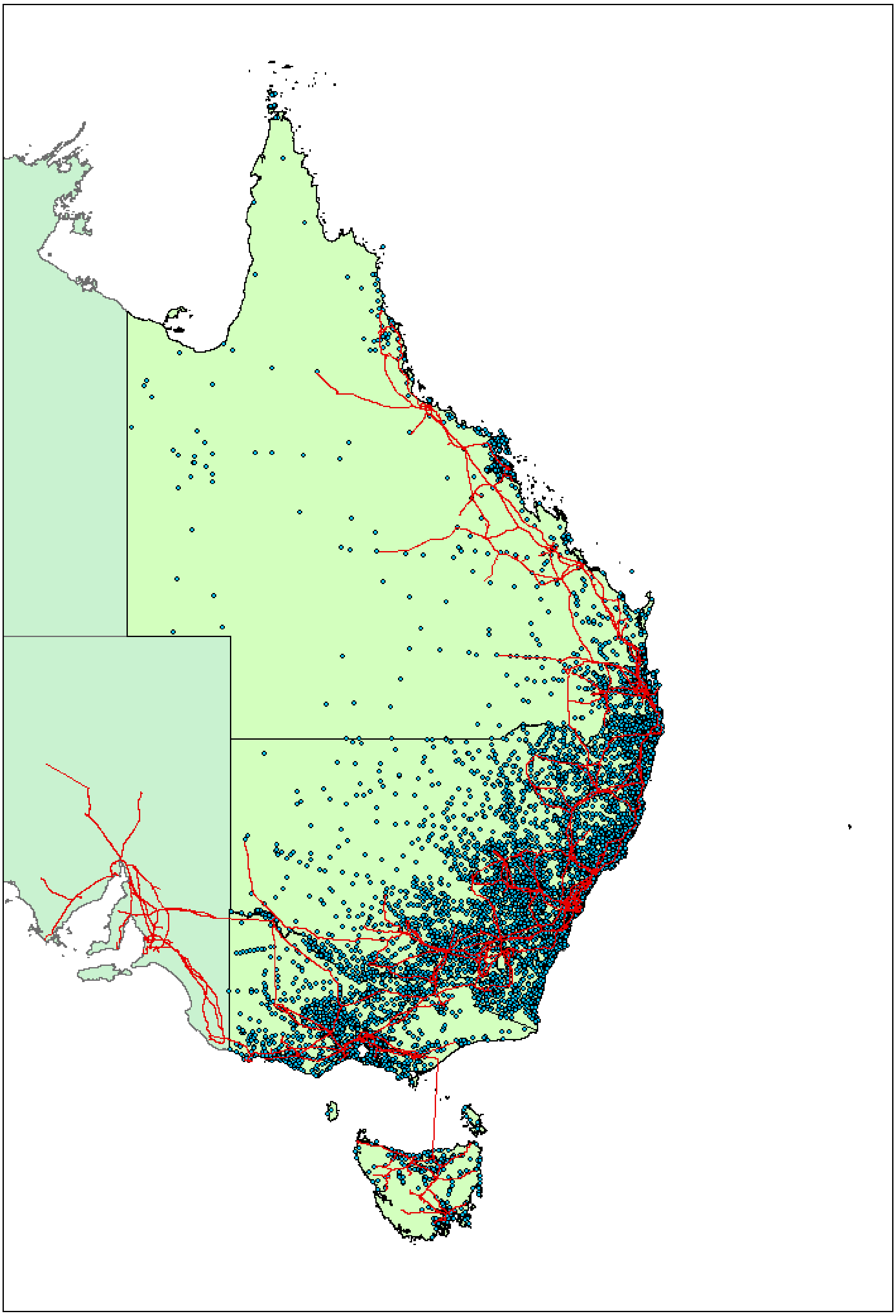

Figure 18: Each blue dot represents a city, town or place considered in this case study. The red lines represent transmission and subtransmission assets within the National Electricity Market

Sources: [85–88]

With the demand management study in [89] considered as background, we propose the following hypothetical demand management case study, where we assume the following:

- a 25 MW reduction in peak demand is required in 2020 on the transmission network in Eastern Creek, New South Wales
- Eastern Creek has a 330 kV/132 kV substation and a 132 kV/66 kV substation, each with a spare bay for connecting 330 kV, 132 kV or 66 kV, respectively
- the peak demand on the Eastern Creek transmission network typically occurs on hot summer weekdays between about 3 pm and 6 pm, on a few days in the year, and has a typical duration of 3 hours
- the expected cost to increase the capacity of the 330 kV network (by 25 MW) in Eastern Creek exceeds $200 million
- three suitable sites for a 50 MW/75 MWh battery bank have been identified close to the Eastern Creek 66 kV, 132 kV and 330 kV networks; each site covers 0.6 ha of land
- the distance from each of the three sites to a respective substation in Eastern Creek is as presented in Table 9; these distances were calculated using data provided in [85–87].

Table 9: Assumed distances (km) from each site to a 330 kW/132 kV or a 132 kV/66 kV substation in Eastern Creek

Site location	66 kV	132 kV	330 kV
Eastern Creek, NSW	1.96	1.83	1.94
Erskine Park, NSW	2.58	0.29	0.19
Horsley Park, NSW	2.82	0.02	2.86

NSW, New South Wales

Table 10 combines the distances in Table 9 with the generic construction and connection costs in Table 7 to show the cost of connecting the 50 MW/75 MWh battery bank to different voltage levels. It shows that a connection to the 66 kV in Eastern Creek costs significantly less than a connection to the 132 kV and 330 kV networks in Eastern Creek.

Table 10: Assumed cost to connect a battery bank from each site to a respective subtransmission or transmission substation in Eastern Creek

Site location	66 kV	132 kV	330 kV
Eastern Creek, NSW	$7.08 m	$11.37 m	$33.49 m
Erskine Park, NSW	$7.42 m	$10.21 m	$30.34 m
Horsley Park, NSW	$7.55 m	$10.02 m	$35.15 m

NSW, New South Wales

Table 11 shows projected minimum and maximum costs of a 50 MW/75 MWh battery bank (including inverter and land costs). Specifically, it shows the costs of an Li-ion–based battery bank and a flow battery bank in the years 2020 and 2035. The table shows a significant reduction in the cost of both battery technologies over the 15-year period, and that the cost of Li-ion technology is significantly less than the cost of flow-based technology in both 2020 and 2035.

Table 11: Assumed cost of a 50 MW/75 MWh battery bank, including inverter and land costs of 0.6 hectares

Year	Li-ion minimum	Li-ion maximum	Flow battery minimum	Flow battery maximum
2020	$35.5 m	$91 m	$100.5 m	$206.5 m
2035	$14.5 m	$46 m	$30.5 m	$74.5 m

Li, lithium

Table 12 shows the projected total cost of a 50 MW/75 MWh battery bank connected to a spare 66 kV feeder bay in an Eastern Creek subtransmission substation for the year 2020. The projected costs include a step-down transformer from 66 kV to 11 kV at each of the three sites. The table shows that a Li-ion 50 MW/75 MWh battery bank would potentially provide cost savings to a transmission operator in cases where a battery bank connection in close proximity to a 66 kV feeder bay was available. However, in 2020, a flow-based battery bank of 50 MW/75 MWh could potentially cost the transmission operator more than $200 m at each of the three site locations, as shown by the maximum costs in Table 12.

Table 12: Assumed total cost of installing and grid-connecting a 50 MW/75 MWh battery bank, including land costs of 0.6 ha, a DC/AC converter and an associated step-up transformer

Site location	Year	Li-ion minimum	Li-ion maximum	Flow battery minimum	Flow battery maximum
Eastern Creek, NSW **66 kV**	2020	$53 m	$108 m	$118 m	$224 m
Erskine Park, NSW **66 kV**	2020	$54 m	$109 m	$119 m	$224 m
Horsley Park, NSW **66 kV**	2020	$53 m	$109 m	$118 m	$224 m

DC/AC, direct current/alternating current; Li, lithium; NSW, New South Wales

The results of this case study confirm that battery storage may become a viable demand management strategy for operators of transmission or subtransmission networks. Also, the costs associated with Li-ion battery technology are rapidly decreasing; hence, managing peak demand in both transmission and distribution networks in the near future will become increasingly cost-effective with battery storage. However, costs associated with land in CBD locations, together with connection costs at transmission or subtransmission voltages, are significant. Therefore, a case-by-case demand management assessment is required to determine the cost-effectiveness of large-scale, grid-connected battery banks at different network locations. This finding is not consistent with the demand management study in [89], since battery costs in 2009 were more than $2000/kVA.

5.2 Commercial and industrial customers

The economic viability of battery storage for commercial customers is evaluated in two parts:

- the deployment of storage systems at commercial premises with or without solar PV for different tariff structures, to reduce their annual electricity costs
- the deployment of storage systems to reduce the cost of a new connection for an industrial-sized customer; in this case, we use a small-scale generation site (< 30 MW wind or solar PV farm) rather than a load, because the data are more easily available but the principle remains the same for connecting a load.

5.2.1 Commercial Customers: Deployment of storage at premises

The economic viability of ES at commercial premises is affected by the:

- annual consumption and load profile
- tariff structure of the commercial customer
- presence of on-site generation (e.g. solar PV)

- upfront and ongoing costs of the ESS
- expected life of the ESS
- operational performance of the ESS (e.g. DoD and round-trip efficiency)
- expectations of future retail electricity prices beyond current contractual terms.

End-use cases

Based on the number of factors that affect the economic viability of storage, a number of end-use cases were formed for commercial customers. These cases consider different ES, solar PV and tariff combinations:

- commercial customer that pays a standard tariff[2] of a usage rate and demand charge for grid-sourced electricity:
    - standard: installs a battery storage system under a standard tariff
    - standard(PV): has solar PV and retrofits a battery storage system under a standard tariff
    - standard(IPSS): installs a new integrated solar PV and battery storage system (IPSS) under a standard tariff.
- commercial customer that pays a three-tier TOU tariff for grid-sourced electricity:
    - TOU: installs a battery storage system under a three-tier TOU tariff
    - TOU(PV): has solar PV and retrofits a battery storage system under a three-tier TOU tariff
    - TOU(IPSS): installs a new IPSS under a three-tier TOU tariff.

These six end-use cases will be examined for three different sizes of customers (small, medium, and large) and for all states in the NEM.

Methodology

For each tariff incentive type, a heuristic battery operational regime was selected. For the case of a TOU tariff without PV, the battery is charged during off-peak hours until its maximum capacity is reached, and discharged during peak hours until its minimum capacity is reached. For the case of a standard tariff, a target annual peak is selected, and the battery charged up to its maximum whenever customer demand is below the target peak, then discharged so that the net demand meets the target peak whenever the customer gross demand exceeds that target. For the case of PV with gross metering and a flat import tariff, the battery is discharged whenever customer consumption exceeds PV production, to the minimum battery capacity, and charged whenever PV production exceeds customer consumption. For the case of a TOU tariff with PV, the operational heuristic is slightly more complicated. The battery is charged when PV production exceeds customer consumption and during off-peak times, then discharged during peak times if customer consumption exceeds PV production. A number of different scales of battery energy and power

[2] Standard tariff refers to the tariff that will be offered to a commercial customer; this may vary by state based on their annual consumption.

capacities were investigated, with size being selected where the amount of energy able to be shifted per unit battery capacity starts to decline significantly.

A broad range of battery sizes results in similar financial benefit to the customer. In general, the relationship between battery scale and financial return slowly declines per unit installed capacity, and the particular scale that maximises financial returns is strongly dependent on the individual customer demand profile, which will vary from year to year. This makes it particularly difficult to forecast the scale of battery uptake to within a small range, even for the case of an individual customer focused solely on financial considerations. In practice, it is likely that both residential and small-scale commercial customers will opt for one of a limited range of standard sizes offered by suppliers.

Load profiles

To estimate the economic viability of storage, a key input is the load profile. Estimates of annual electricity consumption are insufficient to determine the economic viability of storage because discharge of the storage requires that there is load to be served. A temporal load profile is preferred, given that the load at a particular commercial premise can be highly variable due to operating hours, building characteristics and size, use of natural gas, and seasonal and climate effects. However, there is considerable difficulty in obtaining temporal load profiles of individual commercial premises. Although a greater proportion of commercial customers than residential customers have interval metering, these metered data are typically not publicly available. Accordingly, for this study we used a half-hourly profile from a feeder from the National Feeder taxonomy study, as shown in Figure 19. Note that our example small, medium and large customers defined here may not coincide with the customer size classifications for various retailers across the NEM.

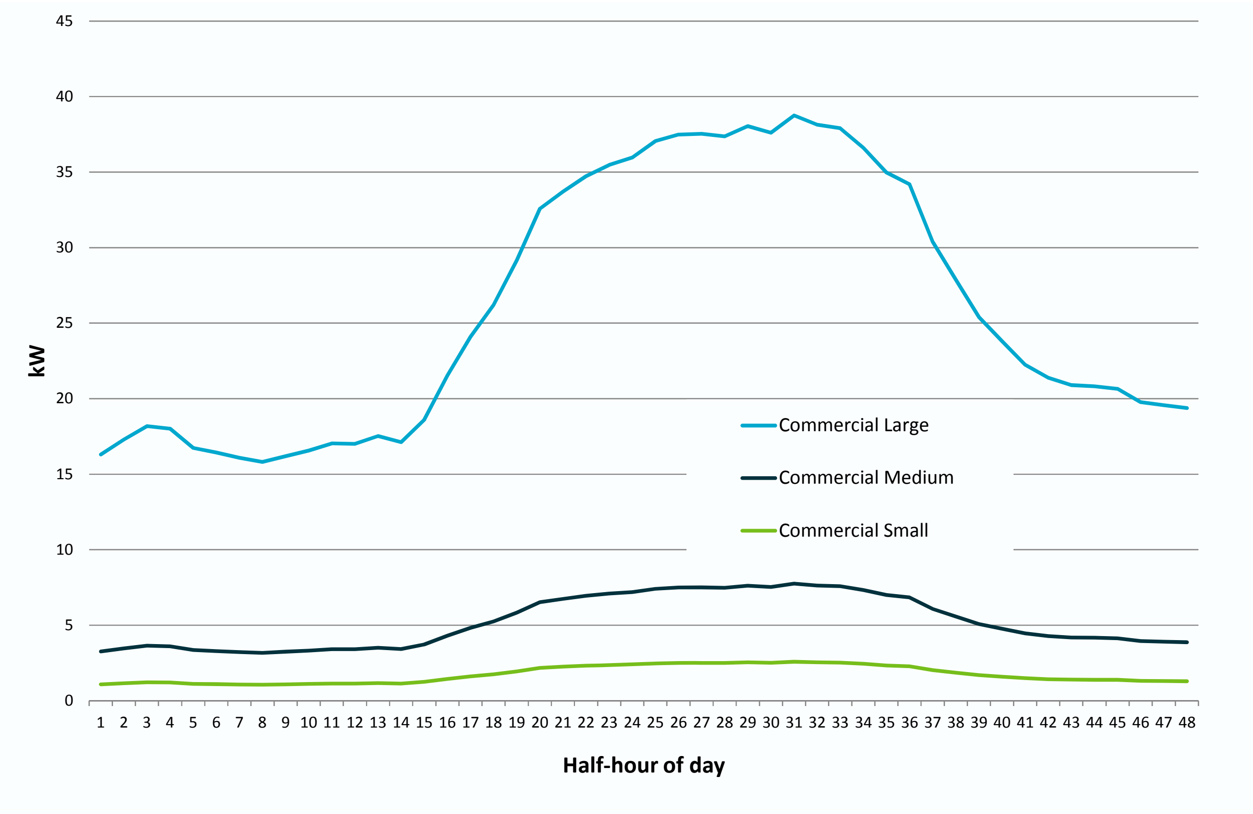

Figure 19: Assumed load profile for commercial customers

As a typical example of a commercial load profile, the maximum consumption occurs during working hours in the middle of the day, mainly reflecting operating hours and requirements for space heating and cooling. A reasonably flat baseload component of consumption occurs during off-peak hours overnight.

Tariff structures

Commercial customers can choose from a number of different tariff structures that are offered by retailers. The actual structure of the tariff that businesses are typically offered (referred to here as the standard tariff) has some variation based on the consumption level and the state in which the enterprise is located. For example, some contracts may have a two-part usage charge (off-peak and peak) and a demand charge that varies by distribution network, and that is set on a c/kVA/day or $/kW/month basis applied to an estimate of peak demand (typically for the preceding month or year).

With regard to TOU only tariffs, smaller commercial users may be offered two-tier (off-peak and peak) or three-tier (off-peak, shoulder and peak) TOU pricing structures. Typically, the simpler tariff structures with a single rate for energy usage tend to be the least costly for smaller customers. More complex tariff structures (e.g. those with two-tier and three-tier rates depending on TOU, or those that include a maximum demand charge) will often have lower variable costs but higher fixed charges, making them the lowest cost option only for larger customers. For this report, we undertook calculations for all commercial tariffs identified, for all three sample customer sizes, irrespective of whether a customer of the specified size is eligible for the corresponding tariff under current offerings from retailers.

Battery storage needs to be charged in order to provide power at a different time; thus, the tariff structure impacts the operation of the battery system. For a commercial customer, reducing the demand charge may be an attractive strategy, given that this is a relatively large portion of the power bill. Alternatively, for a TOU only customer, shifting load out of the ‘peak’ pricing period might be preferred. The end-user case where a PV system is installed can complicate this story, depending on the correlation between the load and output of the solar PV system.

Table 13 shows the tariff rates in 2015 for the standard tariffs, and Table 14 shows the TOU only tariffs that are used in this analysis.

Table 13: Standard tariffs used in this study, commercial customers

State	Peak	Shoulder	Off-peak	Capacity charge	Capacity charge equivalent c/kW/day
NSW	25.355	21.197	13.266	38.137 c/kW/day	38.137
Vic	19.173 16.621	(16.621)	9.812	76.3499 c/kW/day	20.918

State	Peak	Shoulder	Off-peak	Capacity charge	Capacity charge equivalent c/kW/day
Qld	11.9218	(11.9218)	(11.9218)	31.303 $/kVA/month	102.256
SA[a]	8.3	(8.3)	5.2	11.495 $/kVA/month	37.791
Tas	15.256	(15.256)	(15.256)	193.927 $/kVA/year	59.034

NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

[a] Sourced as personal communication for an individual site as no published South Australian equivalent identified.

Sources: Tariff references T3, T6, T7, T9, T11a, T11b, T14 (see Section 10)

Table 14: Time-of-use tariffs used in this study, commercial customers

State	Peak	Shoulder	Off-peak	Peak hours
NSW	47.685	22.385	11.176	2 pm – 8 pm
Vic	24.508	(24.508)	10.087	3 pm – 9 pm
Qld	29.9676	(29.9676)	21.1266	4 pm – 8 pm
SA	45.452	(45.452)	22.088	7 am – 11 pm
Tas	28.106	18.0378	9.8208	7 am – 11 am 4:30 pm – 10 pm

NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Sources: Tariff references T3, T5, T9, T10, T13 (see Section 10)

There is some variation across NEM states regarding the timing of the peak pricing periods: earlier in the more northerly state of Queensland and later in the southern states of Victoria and Tasmania. In New South Wales, we were able to identify published tariffs with three pricing tiers (i.e. off-peak, shoulder and peak). In other states, the tariffs identified had only two TOU tiers.

We assumed that the tariff rates would not remain constant at 2015 levels, but would change over time based on the projected change from the electricity price forecasts developed by Frontier Economics [90] for the 2015 National Electricity Forecasting Report.

Based on [90], retail electricity tariffs in most Australian states are expected to be declining or flat in real terms for the next decade. This near-term expectation is consistent with recent determination decisions in New South Wales. However, over the medium term, retail electricity prices are expected to increase.

Calculation of payback periods

Estimating the economic viability of battery storage for the different technologies and end-use cases for a commercial entity is a three-step procedure:

1. Impose a reasonable battery use set of rules (charge and discharge cycle) that maximises the financial return from the storage device, within operational limits.
2. Calculate the annual monetary benefit to the enterprise.
3. Calculate the payback period based on the cost of the battery system divided by the annual benefit.

The discussion focuses initially on the two battery retrofit end-use cases ('standard' and 'TOU'), followed by the two battery retrofit to PV end-use cases ('standard(PV)' and 'TOU(PV)'), and lastly the integrated solar PV and storage system end-use cases ('standard(IPSS)' and 'TOU(IPSS)').

Battery retrofit end-use cases

The discounted payback period evolution for mid-range battery costs (using the lowest cost Lithium-ion chemistry) for our large-size commercial entity on a standard tariff without PV, assuming that the battery system is purchased in a given year between 2015 and 2035, is shown in Figure 20.

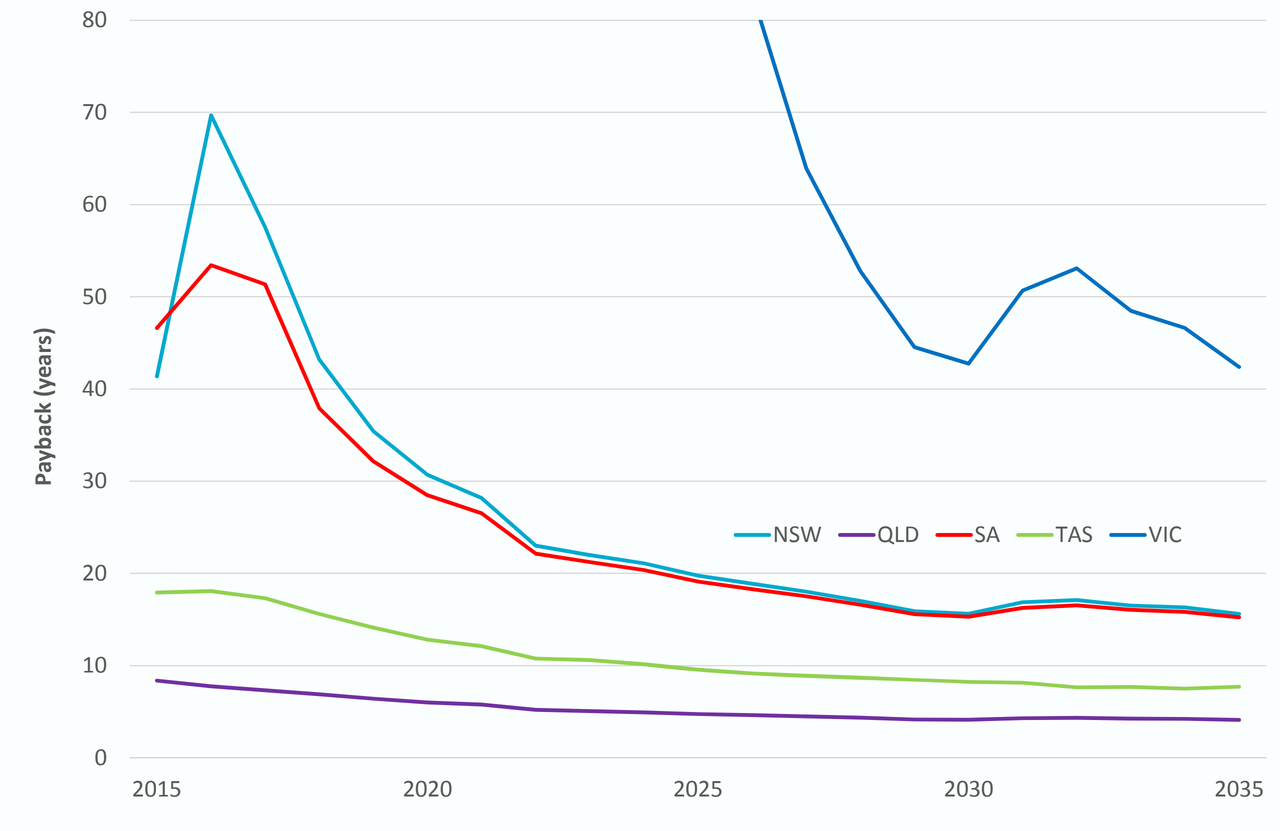

Figure 20: Discounted payback periods for mid-range battery costs, standard end-use case, large-size commercial customer, NEM states

NEM, National Electricity Market; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Figure 20 shows that there is considerable variation across the states in the NEM. For this type of tariff regime (time varying volumetric charge, and a $/kW or c/kVA demand or capacity charge), the installation of storage is most viable when demand charges are significant. Based on the standard tariffs used (see Table 13), Victoria is the least attractive under this tariff regime, given that it has the lowest demand or capacity charge among the NEM states. In contrast, Queensland is the most attractive, given that it has the largest capacity charge among the NEM states, followed by Tasmania. New South Wales and South Australia have similar demand charges, reflected in similar payback periods. The exception is early in the projection period, when New South Wales retail tariffs are expected to decline in real terms. This reduces the attractiveness of storage in the next few years (spike in payback period observed in Figure 20).

Figure 21 shows the discounted payback period evolution for mid-range battery costs for a large-size commercial customer on a TOU tariff without PV, assuming that the battery system is purchased in a given year between 2015 and 2035.

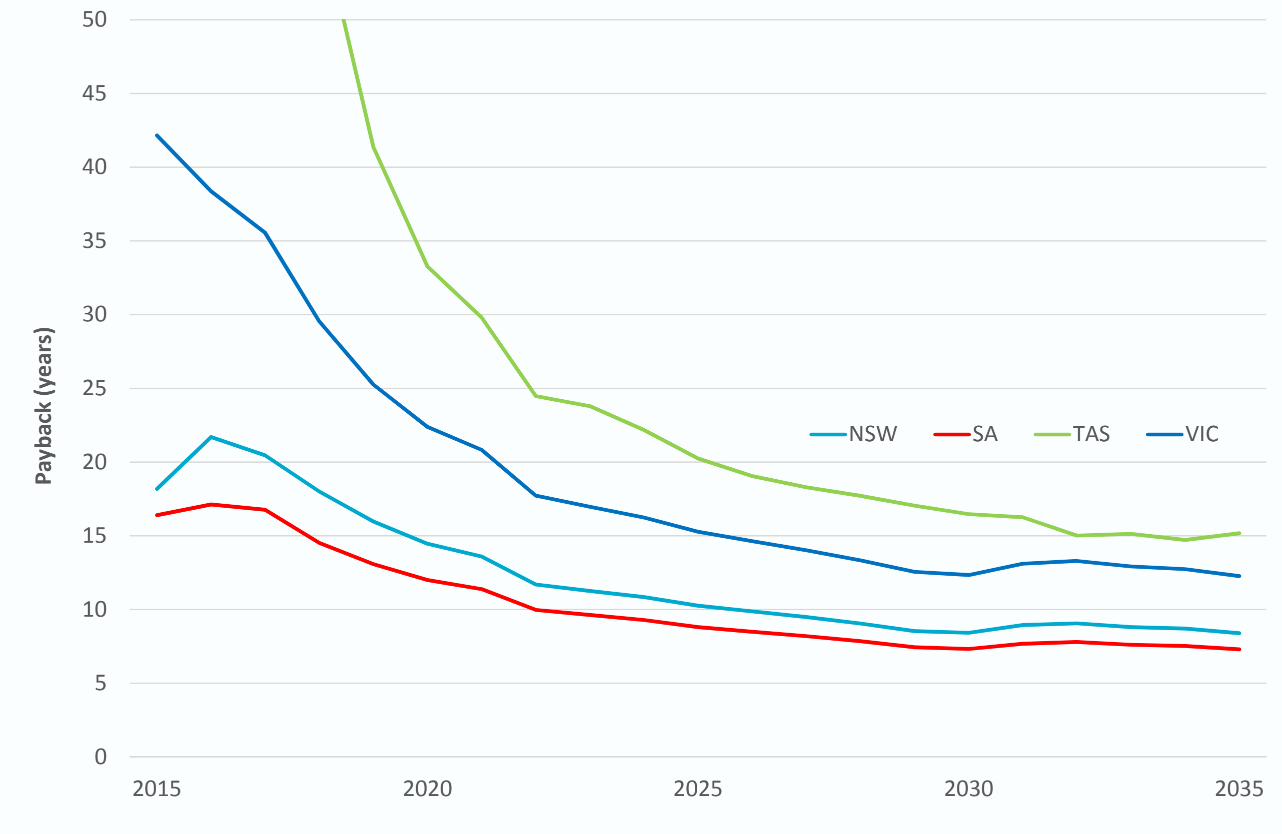

Figure 21: Discounted payback periods for mid-range battery costs, TOU end-use case, large-size commercial customer, NEM states

NEM, National Electricity Market; NSW, New South Wales; SA, South Australia; Tas, Tasmania; TOU, time of use; Vic, Victoria

Similar to the standard tariff case, Figure 21 shows that there is considerable variation across the states in the NEM. The lowest payback periods are experienced by New South Wales and South Australian enterprises, at 16–18 years in 2015 and around 7–8 years by the end of the projection period. This reflects the TOU tariffs assumed for this study. Table 14 shows that New South Wales and South Australia have the greatest differential between peak and off-peak usage rates, which improves the viability of storage (charge in off-peak, discharge during peak) in these states. In contrast, the viability of storage in Victoria, Tasmania and Queensland is much less (longer payback periods), given the TOU tariff rates assumed in this study.

Battery retrofit to PV end-use cases

Figure 22 shows the discounted payback period evolution for mid-range battery costs for a large-size commercial customer on a standard tariff with PV, assuming that the battery system is purchased in a given year between 2015 and 2035.

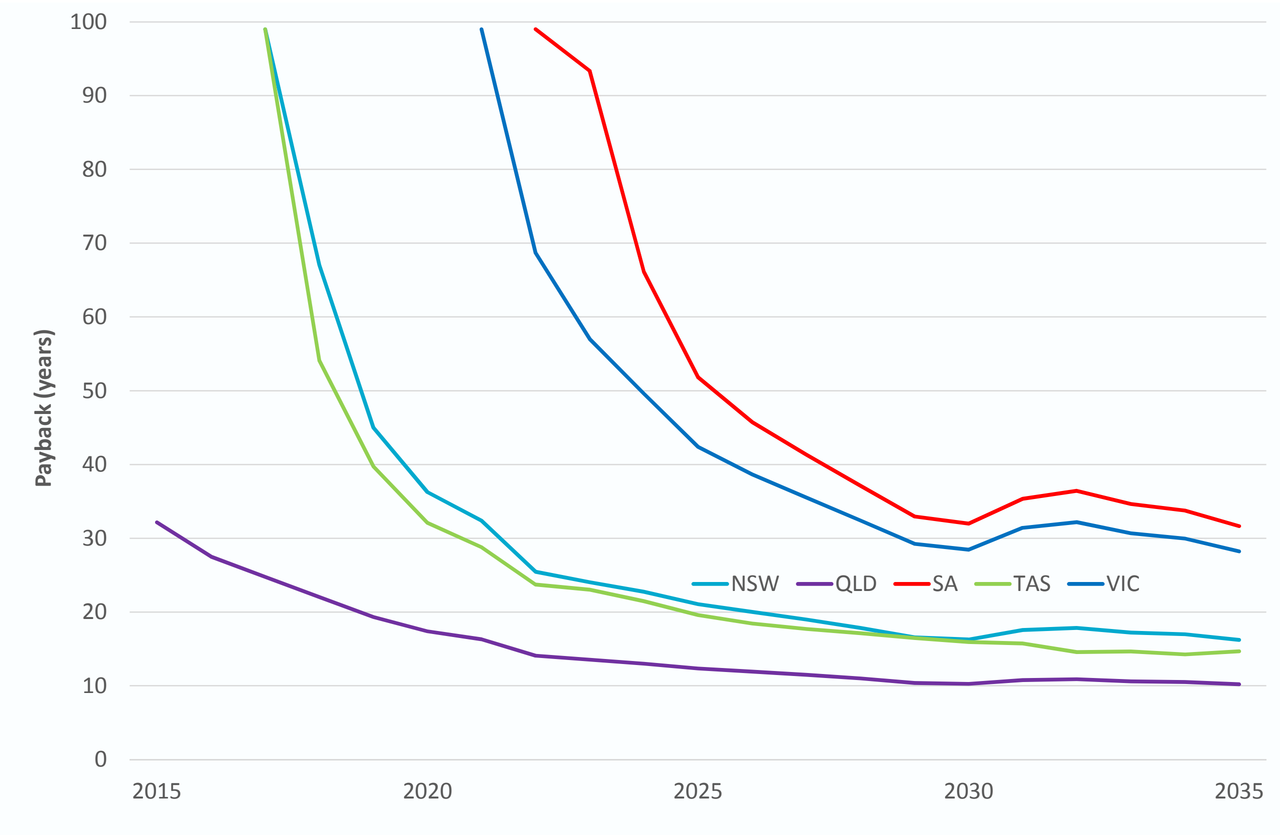

Figure 22: Discounted payback periods for mid-range battery costs, standard(PV) end-use case, large-size commercial customer, NEM states

NEM, National Electricity Market; NSW, New South Wales; PV, photovoltaic; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Figure 22 shows that, under a standard tariff, retrofitting battery storage at commercial premises that already have solar PV does not provide a better return than the no PV case (see Figure 20). Payback periods are long, declining to around 10 years in Queensland and around 15 years in New South Wales and Tasmania by the end of the projection period.

The economic case for installing battery storage for a large-size commercial premise on a TOU tariff with PV cannot be justified for most states in the NEM. For New South Wales, there is some additional value of battery storage when retrofitted to an existing PV system; however, the payback period does not fall below 20 years. This is because the solar PV system has already provided significant value by producing electricity during shoulder and peak-price periods, meaning that there is less value for the battery system to capture. Under a TOU tariff without solar PV, the value that the battery storage system can capture for the assumed operational regime is much greater and the payback periods are therefore much shorter.

Integrated solar PV and storage system end-use cases

Figure 23 shows the discounted payback period evolution for mid-range battery costs for a large-size commercial customer on a standard tariff with PV, assuming that the integrated solar PV and battery system is purchased in a given year between 2015 and 2035.

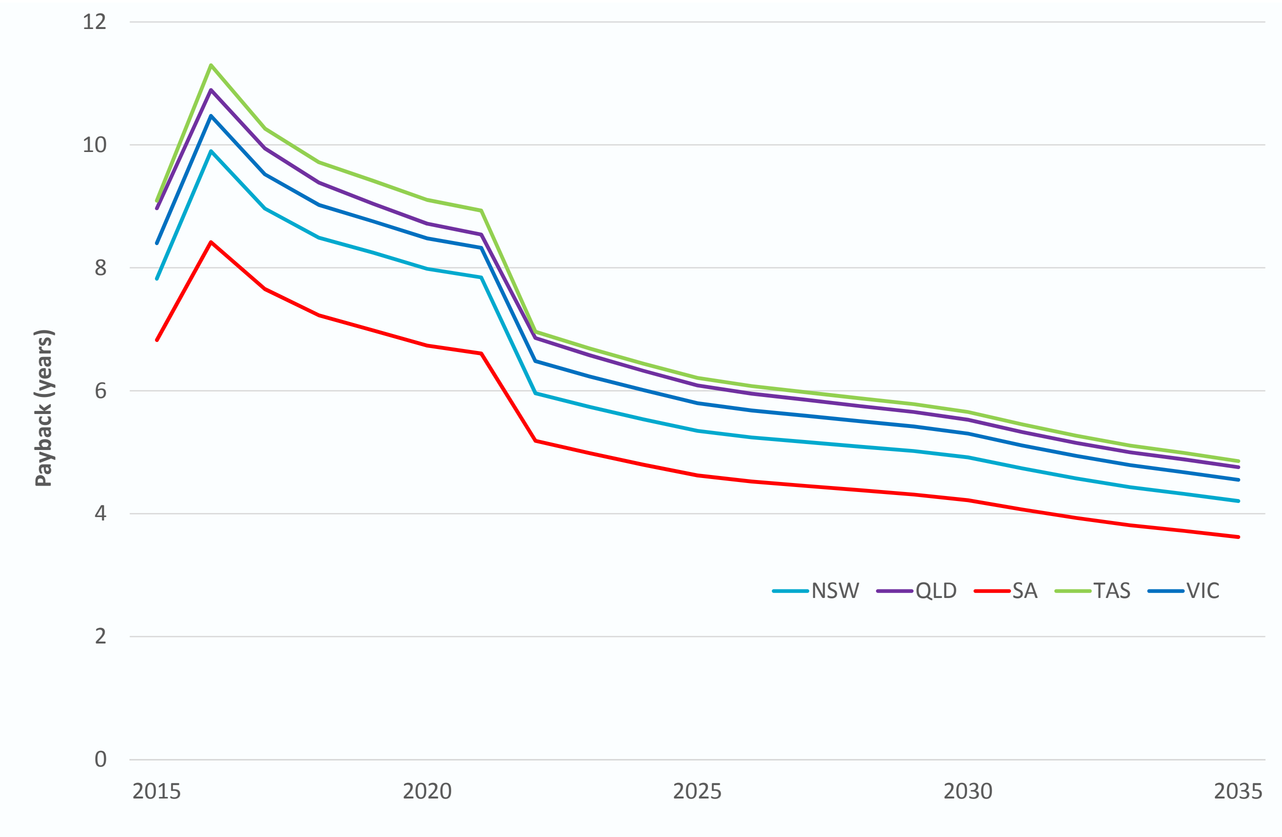

Figure 23: Discounted payback periods for mid-range battery costs, Standard(IPSS) end-use case, large-size commercial customer, NEM states

IPSS, integrated photovoltaic storage system; NEM, National Electricity Market; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Figure 23 shows that the installation of an optimised IPSS has a payback period of less than 10 years in all NEM states within the next decade. This assumes that customised IPSS solutions are available to different customer types based on the assumed load, which may not be the case. Most of the financial benefits to the customer arise from the ability of the battery system to reduce peak demand, thereby significantly reducing the capacity charge. Figure 24 shows the evolution of discounted payback periods under the TOU(IPSS) end-use case.

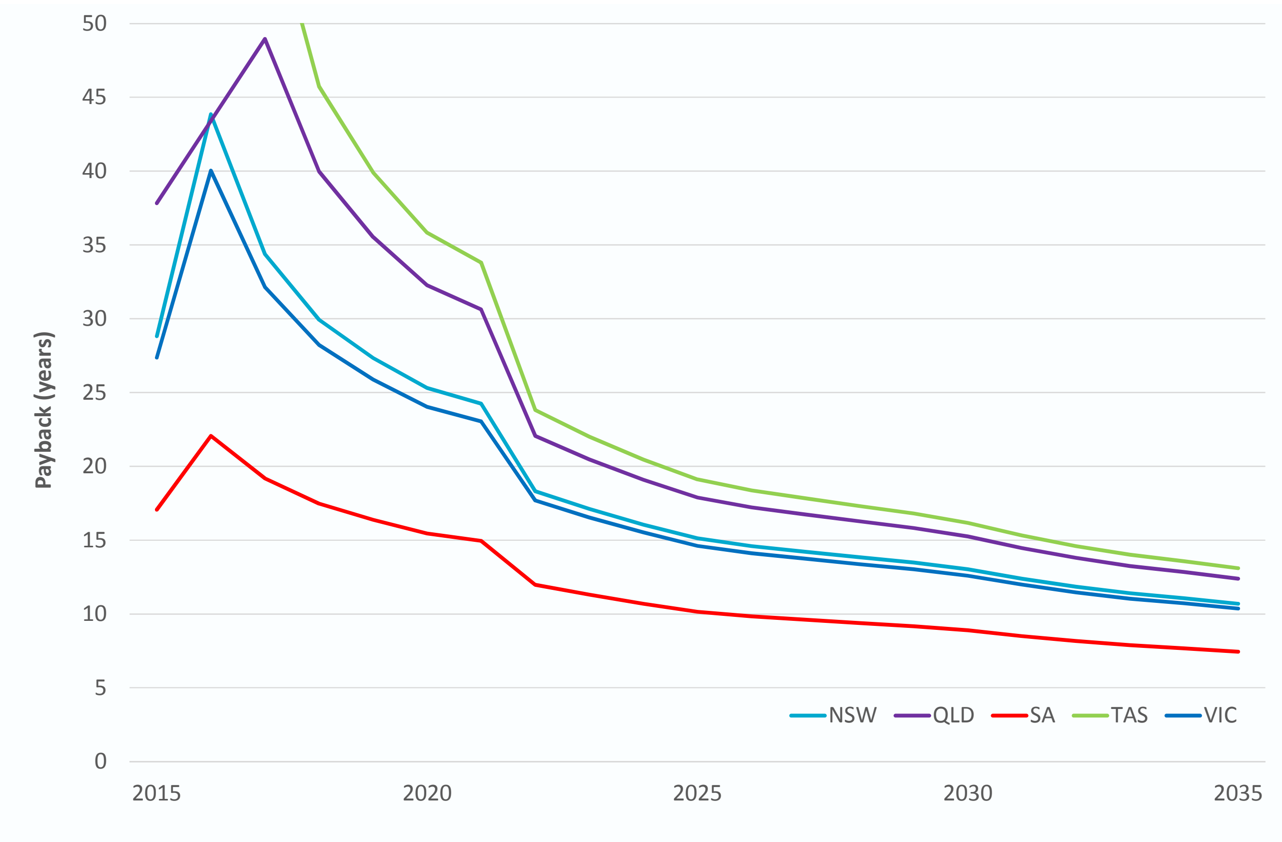

Figure 24: Discounted payback periods for mid-range battery costs, TOU(IPSS) end-use case, large-size commercial customer, NEM states

IPSS, Integrated Photovoltaic Storage System; NEM, National Electricity Market; NSW, New South Wales; SA, South Australia; Tas, Tasmania; TOU, time of use; Qld, Queensland; Vic, Victoria

Figure 24 shows an ordering of the states in the NEM similar to that shown in Figure 23, but in general the payback periods are longer. The longer periods reflect the fact that the financial savings due to shifting net load from peak to off-peak periods under a TOU tariff are not as large as those due to the ability to reduce a peak capacity charge.

Summary

Figure 25 shows the discounted payback period for snapshot years for mid-range battery costs for a large-size customer by end-use case for all NEM states.

Figure 25: Discounted payback periods for mid-range battery costs, large-size commercial customer by end-use case, NEM states

NEM, National Electricity Market; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Figure 25 clearly shows that the type of tariff and the presence of on-site generation has a significant impact on the viability of ES for commercial customers. In all end-use cases, a standard tariff structure provides greater returns on storage than does a TOU tariff. This mainly reflects the benefits of reduced demand or capacity charges. The most attractive case for large customers is the installation of an integrated battery storage and solar PV system. Returns are greatest under a standard tariff because the battery can contribute to a reduction in capacity charges, in addition to maximising the on-site usage of solar generation and potentially taking advantage of low off-peak prices for consumption during peak periods.

Sensitivity analysis

The key sensitivity of lower projected costs of battery storage and solar PV were examined to gauge the impact on economic viability.

Figure 26 shows the impact of battery and solar PV costs on the payback period for a large-size customer in New South Wales for all end-use cases for snapshot years.

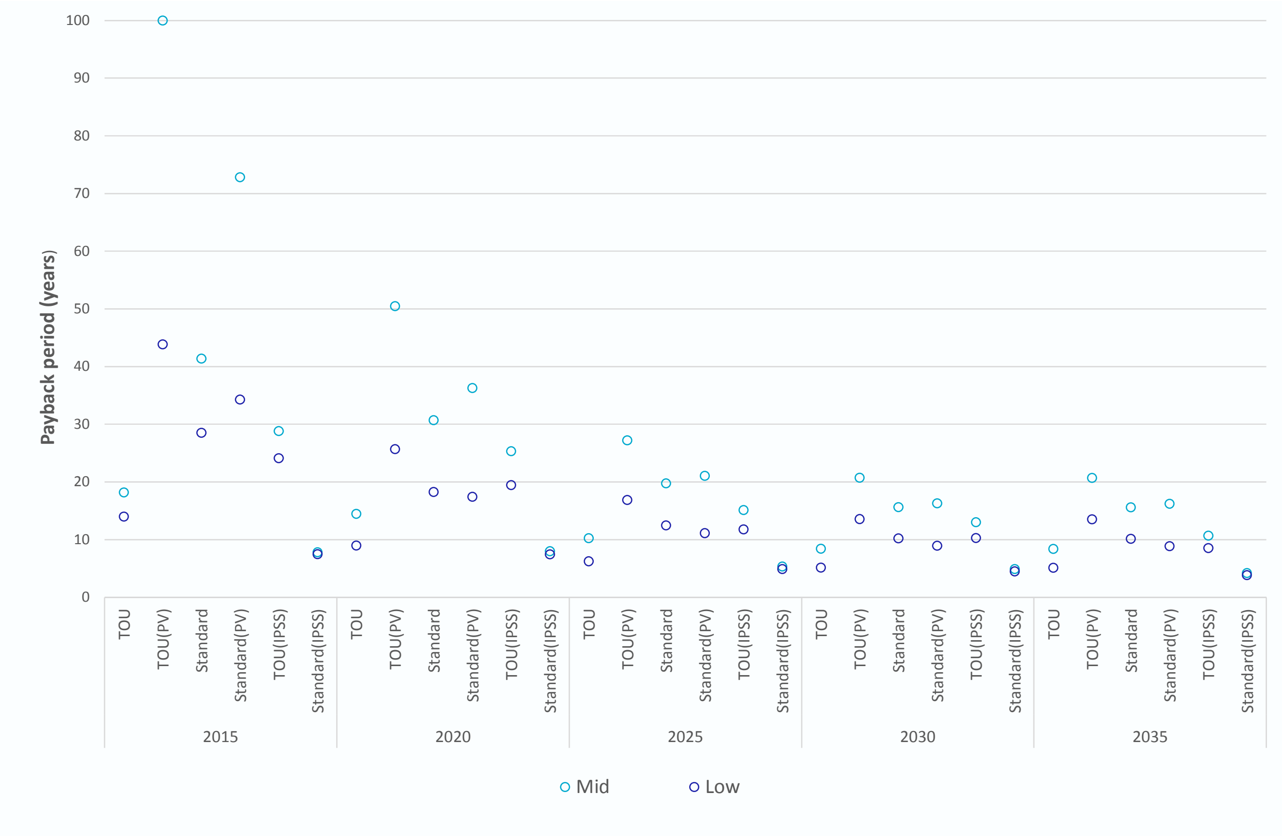

Figure 26: Discounted payback periods for mid-range battery costs, large-size commercial customer by tariff type, with and without solar PV, NEM states

NEM, National Electricity Market; NSW, New South Wales; PV, photovoltaic; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Figure 26 shows that the most significant reductions in payback periods are for the battery retrofit to PV end-use cases if battery costs decline faster than expected. Using the low-range costs from Part I of this report, the payback period for large-size customers in New South Wales is reduced by between 10 and 20 years under both a standard and a TOU tariff. This finding is consistent across all NEM states. Less significant reductions of 3–7 years in the payback period are estimated for the battery retrofit cases. There is less impact on the integrated solar and storage system as the payback periods are already attractive.

Conclusions

The economic viability of battery storage was explored for a number of end-use cases for commercial customers. The results show that:

- installation of an integrated battery storage system with solar PV (IPSS) to commercial premises is the most attractive proposition if the system size can be optimised to the customer's load
- for baseline battery costs and large-size commercial customers in all NEM states, the payback periods for newly installed integrated storage and solar PV systems on a standard tariff decline over the projection period, from 7–9 years in 2015 to 4–5 years by 2035

- for baseline battery costs and large-size commercial customers in all NEM states, the payback periods for newly installed integrated storage and solar PV systems on a TOU tariff decline over the projection period, from 17–29 years in 2015 to 7–11 years by 2035
- for commercial entities without solar PV, the retrofit of battery storage is more attractive in Queensland and Tasmania under standard tariff structures, and in New South Wales and South Australia under TOU tariff structures
- for commercial customers with PV, the retrofit of battery storage is attractive in Queensland and to a lesser extent Tasmania under standard tariff structures
- for commercial customers with PV, the retrofit of battery storage is not viable under TOU tariff structures
- lower battery costs in the future reduce the payback period most markedly for large commercial premises if they are adding storage to an existing PV system
- the results for commercial customers show that the economic viability of storage is highly sensitive to the tariff structure.

5.2.2 Industrial Customers: Reducing the cost of connection

Connection costs for large industrial-sized customers depend on a number of factors, including the distance to nearby transmission or subtransmission assets, the proposed use of those assets, and any capacity constraints requiring remediation to facilitate the proposed connection. Therefore, a large industrial customer may seek to use battery storage to alleviate any capacity constraints restricting or to decrease the cost of the proposed new connection.

This section explores whether it is economically viable to install battery storage to reduce the new connection costs of a large industrial-sized customer. The economic proposition is much the same whether that customer is a load or a small generation source. Given the availability of locational data in [91], we have chosen to assume a small generation source.

We identified cities that are close to both transmission and subtransmission assets within the NEM, with data obtained from [85–88]. We further restricted our search to cities with (or proposals for) a bagasse-fired plant,[3] wind farms or solars farms, as outlined in [91, 92]. See Figure 18 for an overview of all cities considered, with further consideration of three cities in either Queensland or Victoria, based on our selection criteria.

The three cities considered with respect to reducing the cost of connecting a 30 MW wind farm or solar farm to the NEM were Beaconsfield, Queensland; Invermay Park, Victoria; and St Helens Plains, Victoria. We assumed that power quality or capacity constraints in the subtransmission network would restrict the connection of each wind or solar farm, so we further assumed that:

- the maximum output of the wind or solar farm in Queensland would be limited to 20 MW in order to connect to the 132 kV network (we therefore assumed a 30 MW connection to the 330 kV network)

[3] Bagasse is the fibrous material that is left after sugarcane or sorghum stalks are crushed to extract their juice

- the maximum output of the wind or solar farm at each site in Victoria would be limited to 20 MW in order to connect to the 66 kV network (we therefore assumed a 30 MW connection to the 220 kV network for each site).

With the above as background, we investigated the differences in connection costs from the subtransmission to the transmission network. From these cost differences, we considered the break-even cost associated with installing battery storage at each site to limit the maximum output of the wind or solar farm to 20 MW. Table 15 presents assumed costs to connect a solar or wind farm to the electrical grid at a particular voltage. These costs assume a direct (otherwise known as a teed) connection to a nearby overhead conductor, and include protection and control cost. They do not consider customer-specific step-down transformers that would be located on the generator's site. The costs in Table 15 are estimated from the generic overhead construction costs and connection costs assumed in Table 7.

Table 15: Assumed costs to connect a wind or solar farm to a subtransmission or transmission substation

City	66 kV	132 kV	220 kV	330 kV
Beaconsfield, Qld	–	$10.5 m	–	$32 m
Invermay Park, Vic	$6.2 m	–	$23 m	–
St Helens Plains, Vic	$6.2 m	–	$27 m	–

Qld, Queensland; Vic, Victoria

Table 15 shows that a battery storage system that limits the maximum output of the wind or solar farm to 20 MW would need to cost less than:

- $21.5 m to facilitate a connection to the 132 kV network in Beaconsfield, Queensland
- $16.8 m to facilitate a connection to the 66 kV network in Invermay Park, Victoria
- $20.8 m to facilitate a connection to the 66 kV network in St Helens Plains, Victoria.

Therefore, battery storage co-located with large-scale solar PV or wind farms potentially facilitates a reduction in the cost to connect to the electrical power grid. However, realising these potential savings will probably always require a detailed case-by-case assessment given the diversity of loads and generation profiles of each large industrial-sized customer.

5.3 Residential customer

The economic viability of ES placed in residential premises is affected by a number of factors:

- annual consumption and load profile
- tariff structure of the residential customer
- presence of on-site generation (e.g. solar photovoltaic)
- FiT for on-site generation and its terms of payment (i.e. net or gross metering)
- upfront and ongoing costs of the ESS

- expected life of the ESS
- operational performance of the ESS (e.g. DoD and round-trip efficiency)
- expectations of future retail electricity prices.

The methodology for calculating the economic viability for storage sited at residential premises is the same as that outlined for commercial premises in Section 5.2.1.

5.3.1 End-use cases

Based on the number of factors that affect the economic viability of storage, a number of end-use cases were formed for residential customers. These cases assume different ES, solar PV and tariff combinations:

- residential customer that pays a two-tier or three-tier TOU tariff for grid-sourced electricity:
    - TOU: customer installs a battery storage system under a three-tier TOU tariff
    - capacity: customer installs a battery storage system under a two-tier TOU tariff that has a capacity charge
    - TOU(PV): customer has solar PV and retrofits a battery storage system under a three-tier TOU tariff
    - TOU(IPSS): customer installs a new IPSS under a three-tier TOU tariff.
- residential customer that pays a flat tariff for grid-sourced electricity:
    - flat(PV): customer has solar PV and retrofits a battery storage system under a flat tariff
    - flat(IPSS): customer installs a new IPSS under a flat tariff.

These six end-use cases[4] will be examined for three different sizes of customers (small, medium, and large) and for all states in the NEM. The specific tariff rates used will be discussed in the subsequent section on tariff structures.

5.3.2 Load profiles

The load profiles are based on a random sample of available smart meter profiles from each NEM region. The profiles were at half-hourly resolution, but were aggregated up to hourly resolution. For New South Wales (including the Australian Capital Territory), South Australia and Victoria, the distribution of the load profiles was segmented, based on their average daily electricity consumption:

- *large consumers* – households with consumption above the 75th percentile

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[4] The end-use case of installing a battery storage system under a flat tariff was not explored because there is no economic incentive to install a storage system under a flat tariff.

- *medium consumers* – households with consumption between the 25th and 75th percentiles
- *small consumers* – households with consumption below the 25th percentile.

Queensland and Tasmania were treated separately, due to the limited smart meter data available in these regions. For Queensland, demand profiles for large consumers were obtained from smart meters. Small and medium consumers were assumed to follow the same profile, but their total consumption was scaled down accordingly. For Tasmania, the net system load profile was used to represent the demand profiles for all consumers. Total consumption was assumed to vary with the type of consumers.

The household data assumptions are summarised in Table 16.

Table 16: Household data assumptions

		Average annual consumption (kWh)		
State	Number of smart meters sampled	High demand	Medium demand	Low demand
Queensland	300	10,400	4,400	1,700
New South Wales	1000	11,400	4,900	1,900
South Australia	1000	9,700	4,900	2,300
Victoria	1000	8,200	3,800	1,700
Tasmania	N/A	10,000	4,500	1,900

Source: [94]

The average load profile by customer size and season for New South Wales households is shown in Figure 27.

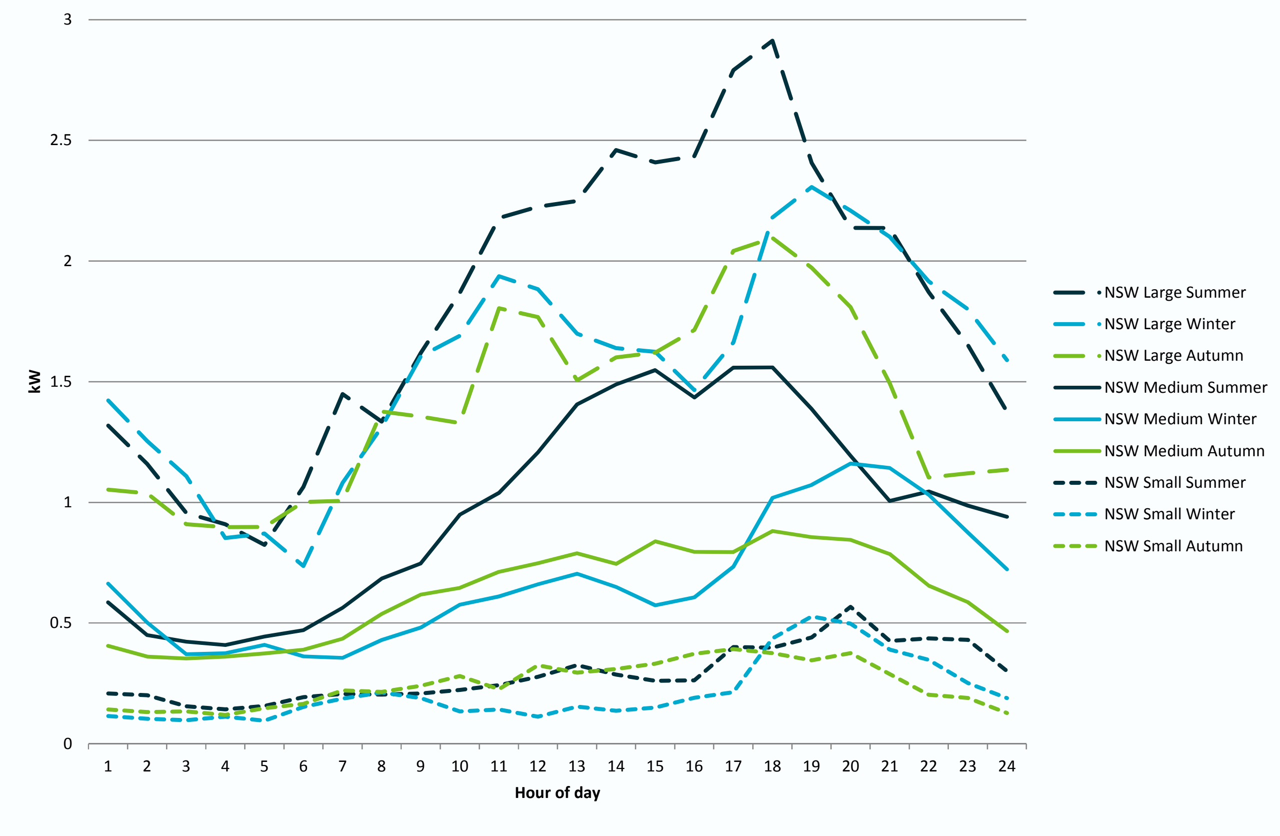

Figure 27: Average load profile by customer size and season, New South Wales households

NSW, New South Wales

Figure 27 shows that there is considerable variation in the loads of different-sized customers, which will affect the sizing and operation of battery storage.

5.3.3 Tariff structures

Residential customers can choose from a number of different tariff structures that are offered by retailers. Most residential customers are on plans that are based either on a flat tariff (with or without controlled load, such as hot water) or an inclining block tariff. Although there has been some adoption of TOU pricing in Victoria, the plans adopted are largely based on a simple peak and off-peak TOU structure. A small number of households in New South Wales, Queensland and Victoria have adopted a tariff structure based on full TOU pricing, typically with three tiers: peak, shoulder and off-peak periods [94]. More recently, some retailers are now offering a capacity tariff to Victorian customers in the United Energy distribution area [95].

Because battery storage needs to be charged in order to provide power at a different time, the tariff structure affects the operation of the battery system. The often used example is the arbitrage case of charging during the low-cost off-peak period and discharging during more expensive peak-price periods. The end-user case where a PV system is installed can complicate this story, depending on the rate and terms of the FiT (i.e. net or gross metering) and the household load profile.

It is expected that, over time, more consumers will be subject to TOU pricing, with or without capacity charges, as part of the general drive towards cost-reflective pricing. Table 17 and Table

18 show the TOU and flat tariff rates in 2015 that are used in this analysis. The ‘capacity’ tariff end-use case is based on the current offering by AGL in the United Energy distribution area [95]. This was the only residential tariff identified with a capacity component, and includes peak and off-peak energy charges of 18.865 and 16.918c/kWh respectively. The capacity charges for Summer and non-Summer periods are 39.369 and 21.032c/kW/day respectively, based on a monthly maximum demand between 3pm and 9pm, with a minimum chargeable capacity of 1.5 kW.

Table 17: Time of use tariffs used for study: Residential (c/kWh)

State	Peak	Shoulder	Off-peak	Peak hours
NSW	51.72827	20.37959	11.21285	2 pm – 8 pm
Vic	35.618	(35.618)	18.106	3 pm – 9 pm
Qld	34.06	24.65	18.92	4 pm – 8 pm
SA	45.452	(45.452)	22.088	7 am – 11 pm
Tas	28.1061	18.0378	9.8208	7 am – 11 am 4:30 pm –10 pm

NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Sources: Tariff references T2, T9, T10, T4, T13 (see Section 10)

Table 18: Flat and PV feed-in tariffs used for study: Residential (c/kWh)

State	Consumption c/kWh	PV feed-in c/kWh
NSW	26.09057	6.0
Vic	29.4	8.0
Qld	27.28	6.53
SA	38.335	6.0
Tas	38.577	5.6

NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Source: [96]

We assumed that the tariff rate changes over time in line with the electricity price forecasts developed by Frontier Economics [90] for the 2015 National Electricity Forecasting Report.

The FiT that were assumed in 2015 are also shown in Table 18. We assumed that the FiT remains constant in nominal terms for the projection period.

5.3.4 Calculation of payback periods

To estimate the economic viability of battery storage for the six end-use cases for a residential customer, we used the same three-step procedure as for commercial customers. The discussion focuses initially on the two battery retrofit end-use cases ('TOU' and 'capacity'), followed by the two battery retrofit to PV end-use cases ('TOU(PV)' and 'flat(PV)'), and lastly the integrated solar PV and storage system end-use cases ('TOU(IPSS)' and 'flat(IPSS)'). All calculations for residential storage options are based on the costs of batteries estimated for Lithium-ion chemistry.

Battery retrofit end-use cases

Figure 28 shows the discounted payback period evolution for mid-range battery costs for a large-size household on a TOU tariff without PV, assuming that the battery system is purchased in a given year between 2015 and 2035.

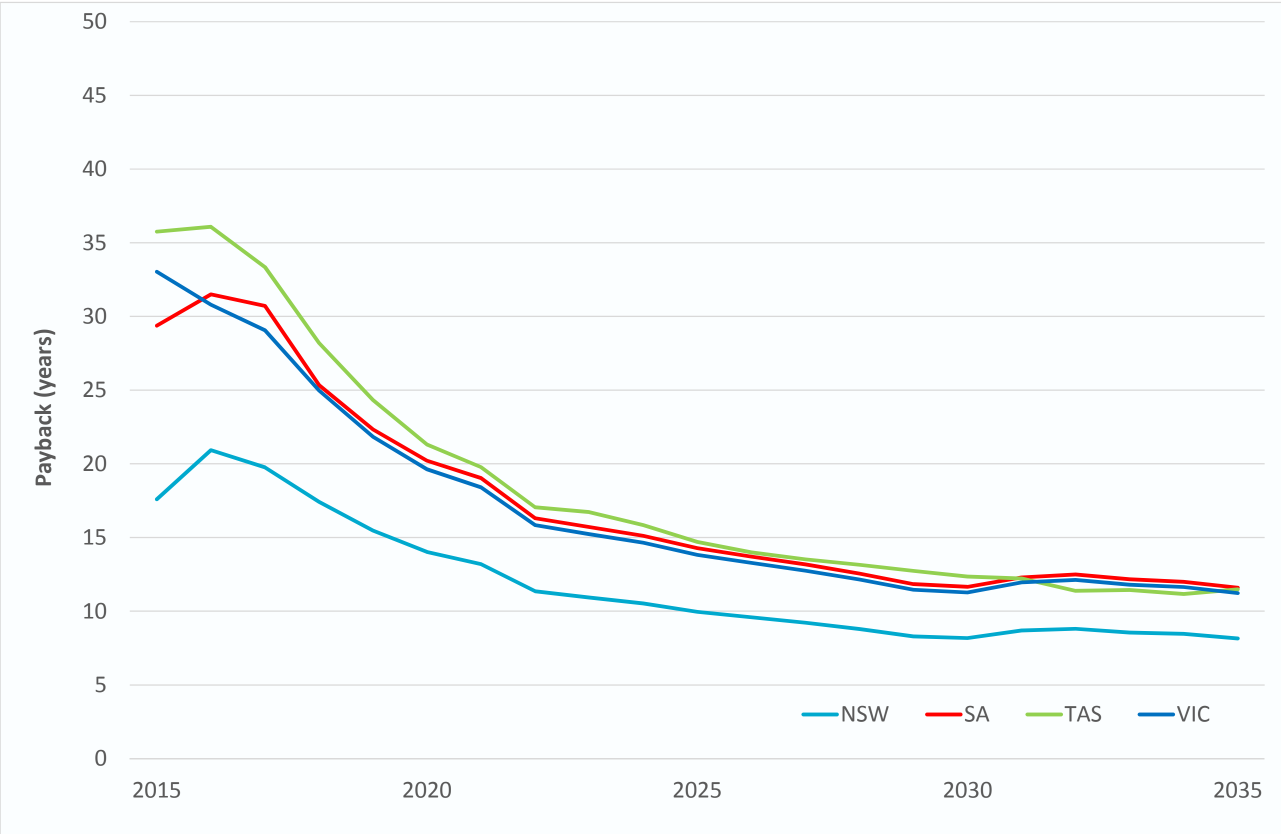

Figure 28: Discounted payback periods for mid-range battery costs, TOU end-use case, large-size residential customer, NEM states

NEM, National Electricity Market; NSW, New South Wales; SA, South Australia; Tas, Tasmania; TOU, time of use: Vic, Victoria

Figure 28 also shows that for the first few years in the projection period, the payback period increases in some states. This reflects falling retail electricity prices that reduce the benefit of battery storage. However, once retail electricity prices stabilise and eventually increase, in combination with declining battery costs, payback periods decline out to 2035.

Additionally, Figure 28 shows that, for most states in the NEM, the discounted payback period for this end-use case is between 17 and 35 years at the start of the projection period. The payback period declines over time, being lowest in New South Wales households by the end of the projection period at around 8 years. Tasmania, South Australia and Victoria also experience reasonable payback periods in 2035, at around 11 years. The exception is Queensland, which has much longer payback periods (> 50 years). This is because Queensland has only a small differential between off-peak and peak prices in the TOU tariff assumed (see Table 17), which significantly reduces the value of battery storage. In contrast, the greater viability in New South Wales and South Australia reflects the largest differential between off-peak and peak prices, and the highest average household loads of the NEM states.

In contrast to the TOU end-use case, installing battery storage under a capacity tariff does not make economic sense for the average small, medium or large consumption household in all NEM states. For the period 2015–2030, the discounted payback period does not fall below 100 years.

The main reason for non-viability for all households is due to the structure of the tariff. The capacity charge is levied on the maximum demand for each month, with a minimum chargeable demand of 1.5 kW. For small and medium customers for whom maximum monthly demands seldom exceed this threshold, the benefits of installing battery storage are negligible. That is, the additional costs of storage for the relatively small benefit of lowering peak demand and therefore capacity charges for a small number of periods in a year is not viable. Even for large customers, this result still holds.

This result may reflect the limitation of using hourly load profiles for the three customer sizes that are averaged over many customers, though not over multiple days. It is likely that for individual households with consumption and maximum monthly demand much higher than the 'average' large household, installing a battery system under a capacity tariff may be much more viable. Note that this was the only residential tariff identified that includes a capacity component, and in the future, there may be other capacity tariffs developed that will make storage more attractive.

Battery retrofit to PV end-use cases

Figure 29 shows the payback period evolution for mid-range battery costs for a large-size household on a TOU tariff with PV, assuming that the battery system is purchased in a given year between 2015 and 2035.

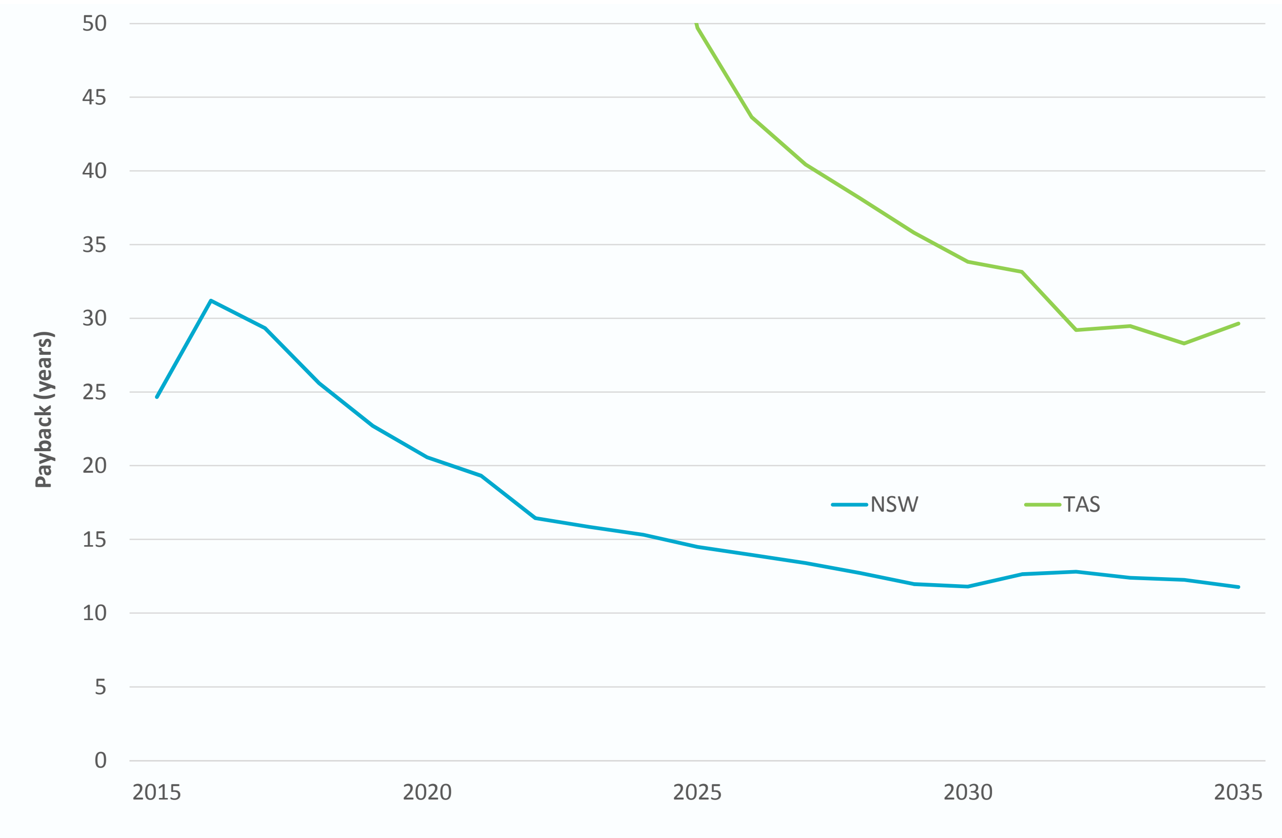

Figure 29: Discounted payback periods for mid-range battery costs, TOU(PV) end-use case, large-size residential customer, NEM states

NEM, National Electricity Market; NSW, New South Wales; PV, photovoltaic; Tas, Tasmania; TOU, time of use

In general, Figure 29 shows that the additional value of battery storage when retrofitted to an existing PV system is much lower than for the TOU end-use case (Figure 28). The discounted payback period does not fall below 100 years for Queensland, South Australia and Victoria. This is because the solar PV system has already provided significant value to households producing electricity during shoulder and peak-price periods. Hence, there is less value for the battery system to capture. Under a TOU tariff without solar PV, the value that the battery storage system can capture is much greater (and therefore the payback period is shorter). The only state showing reasonable payback periods is New South Wales. As that state has the largest differential between off-peak, shoulder and peak rates, installation of a battery system can provide benefits from load shifting. Towards the end of the projection period, the economics improve in Tasmania, but the payback period remains around 30 years.

The economic viability of storage in the battery retrofit to PV end-use cases may be improved in situations where generous gross FiT previously received by the household are due to expire. This case has not been explored in this analysis.

Figure 30 shows the payback period evolution for mid-range battery costs for a large-size household on a flat tariff with PV, assuming that the battery system is purchased in a given year between 2015 and 2035.

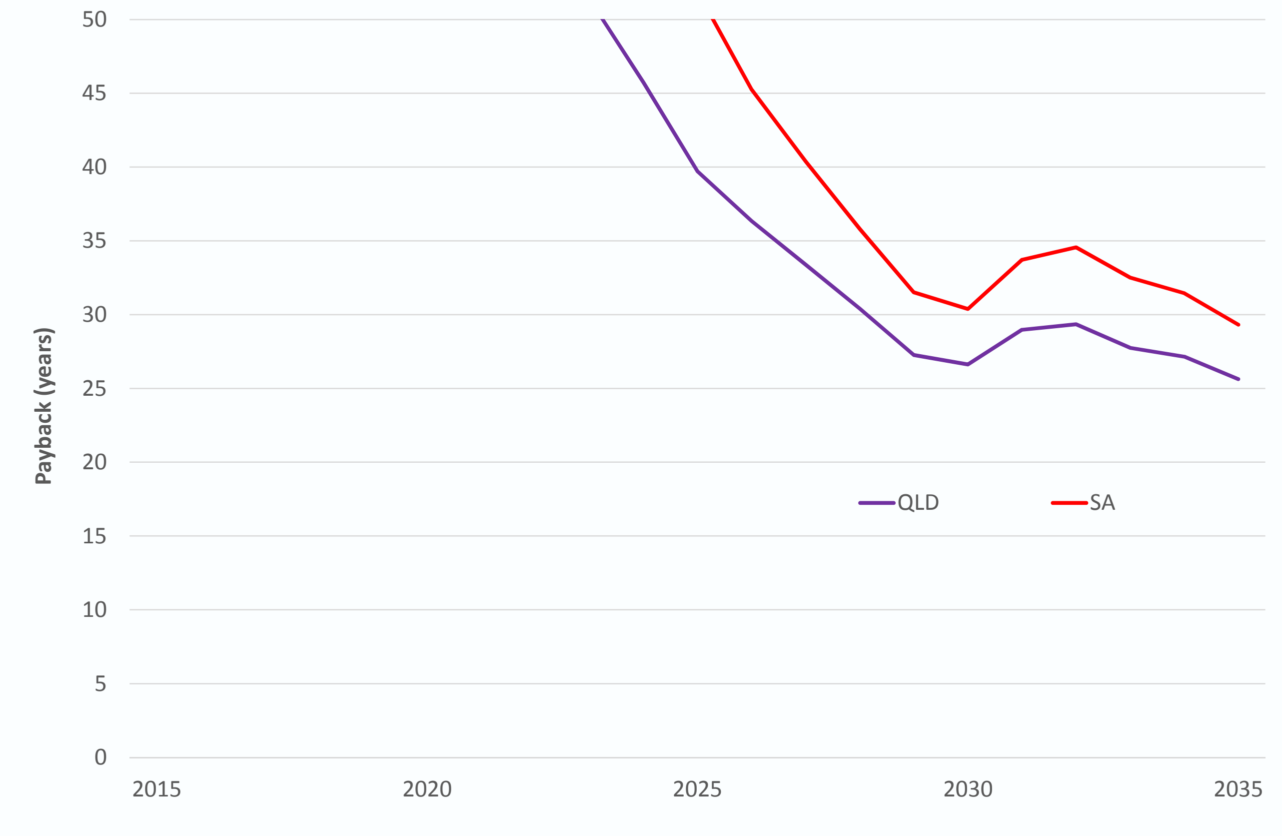

Figure 30: Discounted payback periods for mid-range battery costs, flat(PV) end-use case, large-size residential customer, NEM states

NEM, National Electricity Market; PV, photovoltaic; Qld, Queensland; SA, South Australia

Figure 30 shows that the retrofit of a battery storage system to a household with solar PV on a flat tariff is not attractive to households in New South Wales, Tasmania and Victoria. For large-consumer households in Queensland and South Australian, there is some additional benefit but with a long discounted payback period.

Integrated solar PV and storage system end-use cases

Figure 31 shows the payback period evolution for mid-range battery costs for a large-size household on a flat tariff with PV, assuming that the integrated solar PV and battery system is purchased in a given year between 2015 and 2035. The size of PV system is scaled to the energy demand of each customer. To ensure that on-site generated solar power is mostly used by the customer, with only a limited proportion exported to the grid, it is assumed that the size of PV for residential customers is twice the average power (hourly energy) demand, for commercial customers on a flat tariff is the same as the average power demand and for commercial customers on a TOU tariff is 1.5 times the average power demand (Table 19).

Table 19: PV system scale (kW) for various customers

Sector	State	Tariff	Small	Medium	Large
Residential	NSW		0.43	1.12	2.62
	Vic		0.39	0.88	1.88
	Qld	All	0.39	1.02	2.38
	SA		0.52	1.12	2.22
	Tas		0.43	1.03	2.28
Commercial	All	PV with low feed-in tariff	1.0	3.0	15.0
	All	PV with TOU	1.5	4.5	22.5

NSW, New South Wales; PV, photovoltaic; SA, South Australia; Tas, Tasmania; TOU, time of use; Qld, Queensland; Vic, Victoria

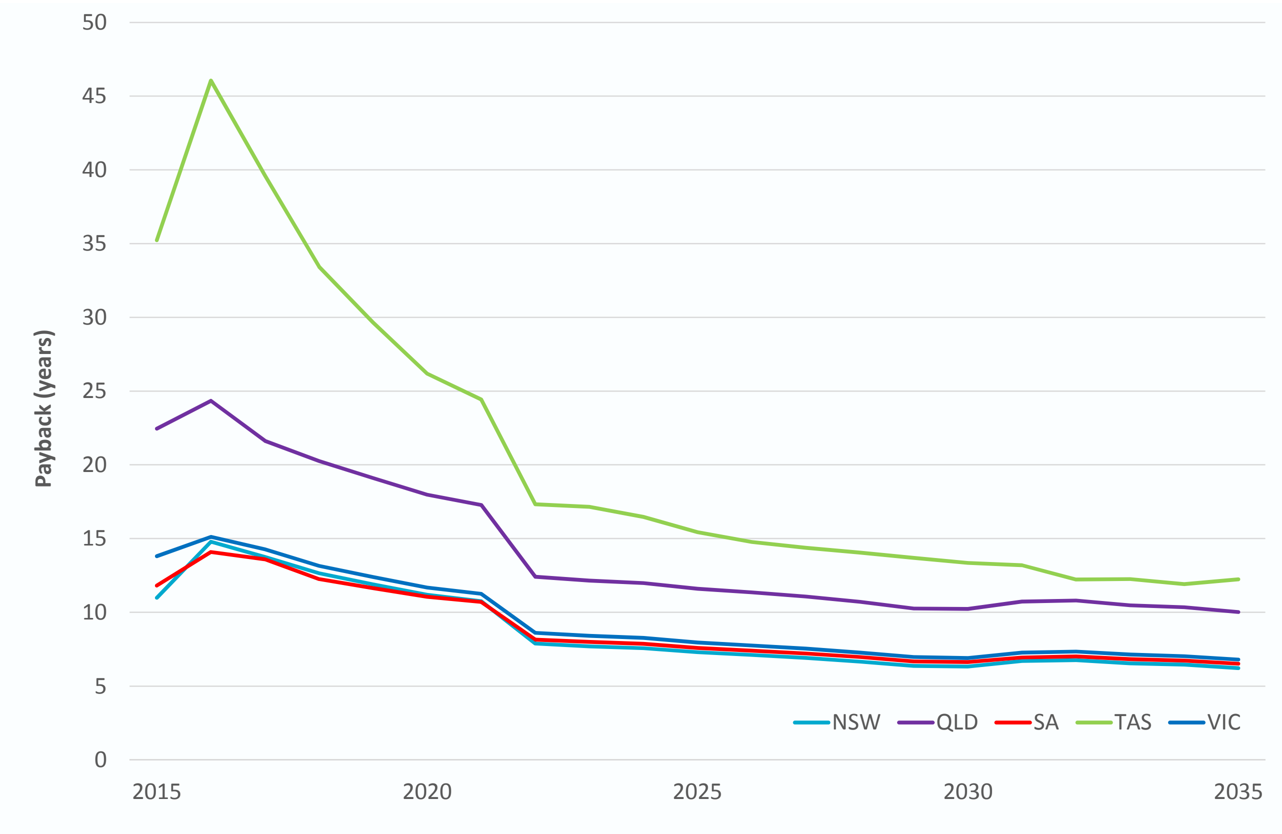

Figure 31: Discounted payback periods for mid-range battery costs, TOU(IPSS) end-use case, large-size residential customer, NEM states

NEM, National Electricity Market; NSW, New South Wales; SA, South Australia; Tas, Tasmania; TOU, time of use; Qld, Queensland; Vic, Victoria

Figure 31 shows that the payback period for an IPSS under a TOU tariff falls below 10 years in most NEM states within the next decade. The jaggedness in the chart reflects the estimated future costs of solar PV from Figure 9. The falling cost of solar PV in concert with falling battery costs (and to a lesser extent rising retail prices), generally results in convergence of viability between the states. However, New South Wales, South Australia and Victoria remain the most attractive as the optimised bundle of solar PV and battery storage in these states provides the most benefit.

Figure 32 shows that installing an IPSS under a flat tariff regime is even more attractive than a TOU tariff structure as it maximises the value of the solar PV system for the household.

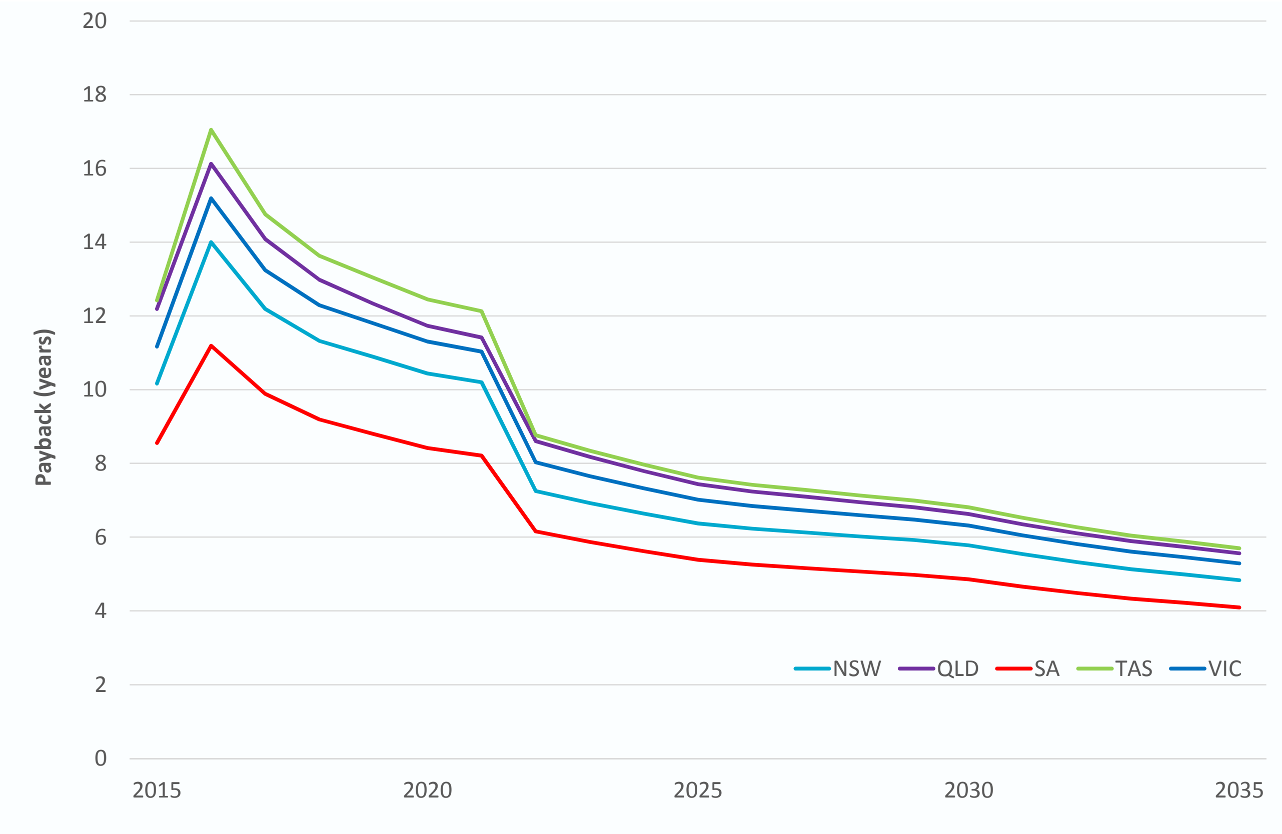

Figure 32: Discounted payback periods for mid-range battery costs, flat(IPSS) end-use case, large-size residential customer, NEM states

IPSS, integrated photovoltaic storage system; NEM, National Electricity Market; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

The Australian Energy Market Operator (AEMO) undertook a similar analysis of the economic viability of PV and storage [93]. Table 20 compares the payback periods reported in [93] with those derived in this study, and Table 21 shows the system specification assumptions made in the AEMO study. The IPSS is more attractive in our study. This is due to a number of differences in the assumptions. Rather than selecting a common size of battery and PV system across NEM state and tariff, as in the AEMO study, we tailored the size of the IPSS to each tariff type and customer scale (see Table 19 and Table 27), resulting in improved benefit–cost ratios. Aiming to achieve a high benefit–cost ratio, and therefore a short payback period, generally results in smaller systems than those designed to achieve a high net present value, since the benefit–cost ratio eventually shows diminishing returns to scale. The battery costs used in our project were also lower than those assumed in the AEMO study; however, both studies reported a discounted payback period at a 5% real discount rate. Although the benefits in our study are based on a heuristic battery management regime and those in the AEMO study are calculated using optimisation, a 10% penalty is applied in the earlier years to represent the impact of suboptimal battery management (e.g. as a consequence of limitations on demand forecasting).

Table 20: Residential 2015–16 estimated payback periods for IPSS (in years) by AEMO in comparison with (this study)

State	Small	Medium	Large
NSW	24 (13.5)	15 (15.7)	9 (7.8)
Vic	20 (33.4)	15 (22.1)	11 (14.8)
Qld	18 (12.7)	14 (18.5)	10 (9.0)
SA	14 (9.0)	11.5 (6.6)	9 (7.9)
Tas	29 (16.4)	23 (12.8)	16 (8.9)

AEMO, Australian Energy Market Operator; IPSS, integrated photovoltaic storage system; NEM, National Electricity Market; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Table 21: System-specifications assumptions, AEMO

	Small	Medium	Large
Rooftop PV (kW)	1.5	3.0	4.0
Battery capacity (kWh)	3	5	7
Battery power (kW)	1.5	2.5	3.3
Battery system installed cost per usable kWh	1370	1370	1370

AEMO, Australian Energy Market Operator

For most NEM states, the economic viability of storage improves as the customer load increases. Discounted payback periods are shortest for large customers and longest for small customers. Discounted payback periods from 2015 to 2035, for all customer types for the six end-use cases explored here, are given in Section 11 (Appendices).

Summary

Figure 33 shows the discounted payback period for the snapshot years for mid-range battery costs for a large-size customer by selected end-use cases[5] for all NEM states.

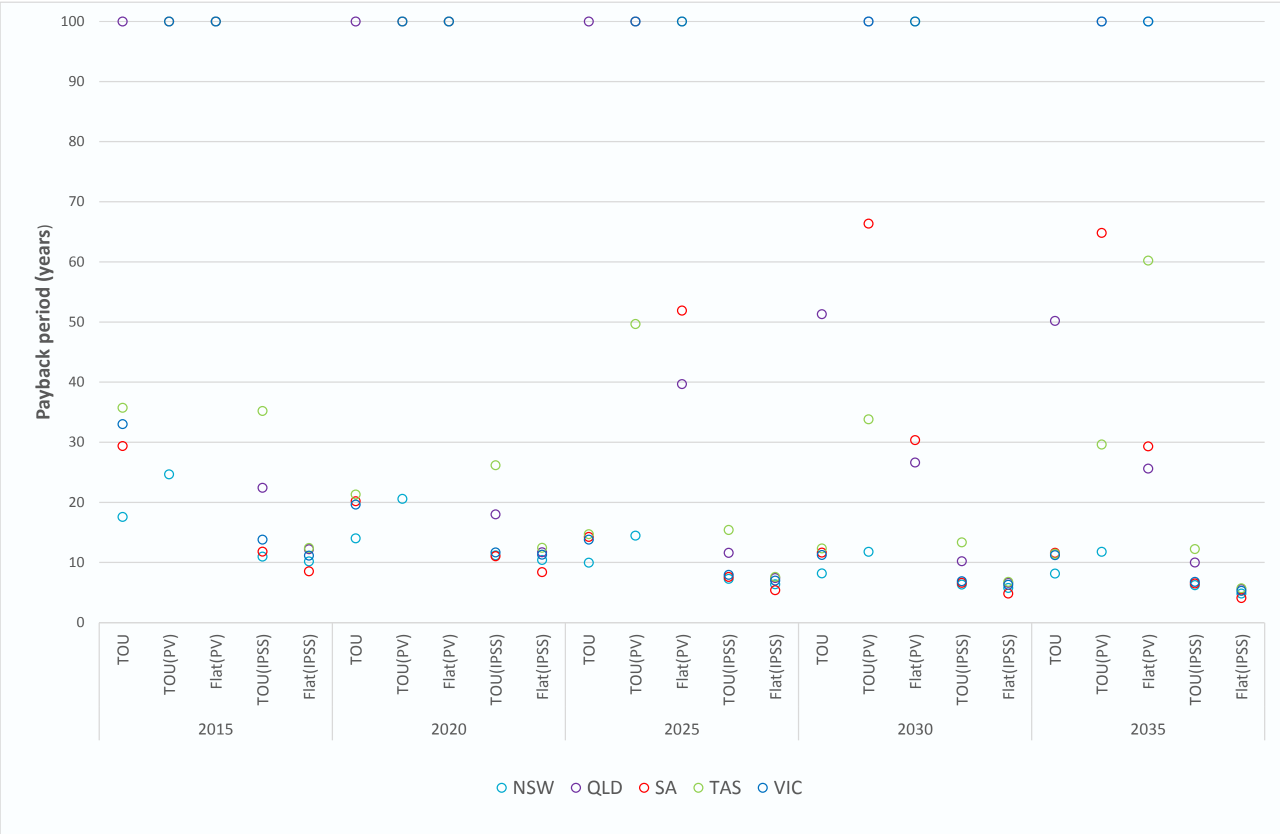

Figure 33: Discounted payback periods for mid-range battery costs, large-size residential customer for selected end-use cases, NEM states

NEM, National Electricity Market; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Figure 33 clearly shows that retrofitting battery storage under TOU pricing provides the most value to households without PV. In contrast, for households that have solar PV installed, TOU or flat tariff pricing may provide the shortest payback period for battery storage, depending on the state. It is also clear from Figure 33 that IPSS end-use cases are the most attractive, reflecting the optimisation of the integrated system to the customer load.

[5] Battery storage was excluded because it was not found to be viable for large-size customers for capacity tariffs.

5.3.5 Sensitivity analysis

We examined the key sensitivity of lower projected costs of battery storage and solar PV to gauge the impact on economic viability.

Figure 34 shows the impact of battery and solar PV costs on the payback period for a large-size customer in New South Wales for selected tariff types[6] for snapshot years.

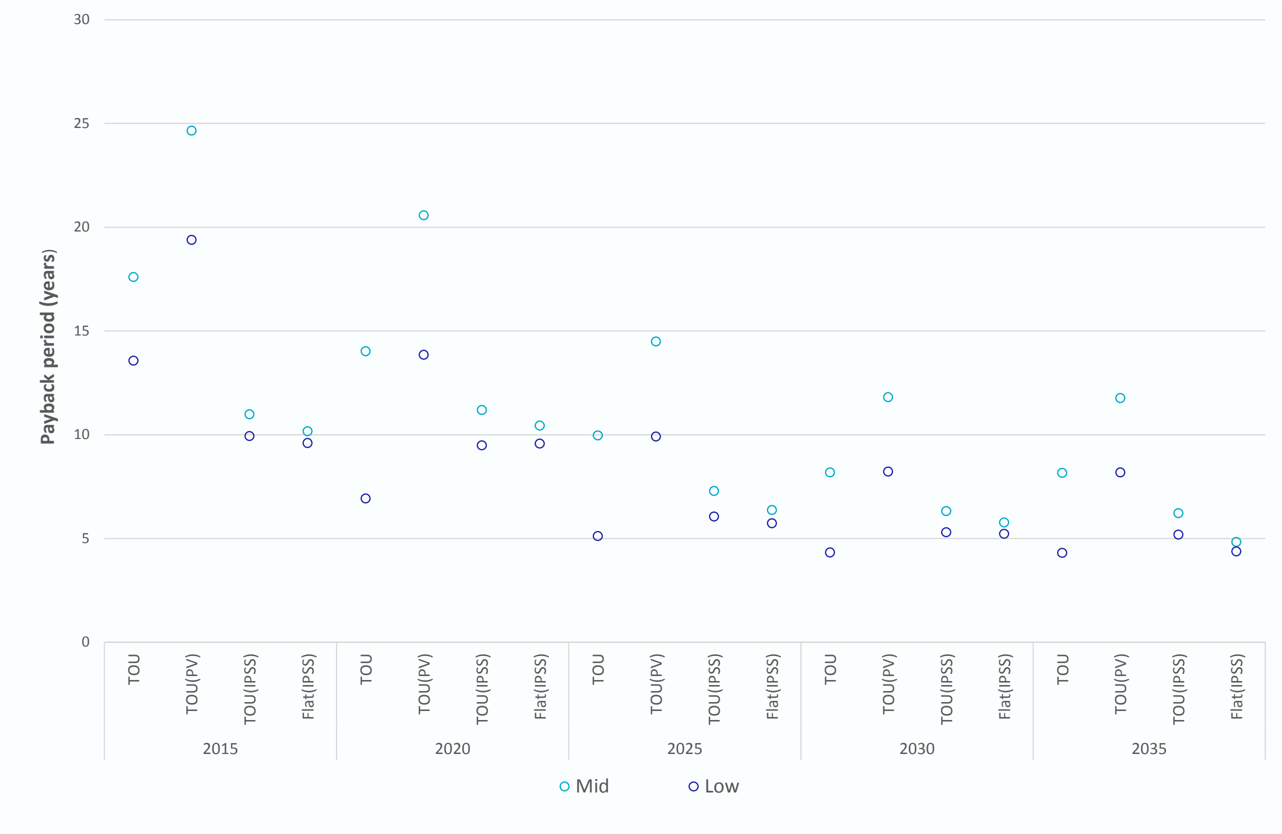

Figure 34: Discounted payback periods for a New South Wales large-size residential customer by selected tariff type, mid- and low-range battery costs

Figure 34 shows that the discounted payback period is reduced for TOU end-use cases if battery costs decline faster than expected. Using the low-range costs from Part I, the payback period for large-size customers in New South Wales is reduced by 4–5 years for most time periods. This finding is consistent across the other NEM states. The reduction in payback period is greatest in earlier years for the TOU(PV) end-use case because the lower battery costs unlock more value of adding the battery to the PV system. For the IPSS cases, the payback results are less sensitive to lower capital costs. This mainly reflects that these end-use cases already have low payback periods under medium capital costs.

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[6] Battery storage was excluded because it was not found to be viable for large-size customers for capacity tariffs.

5.3.6 Conclusions

The economic viability of battery storage was explored for a number of end-use cases for residential customers. The results show that:

- there is greater value of storage when it is installed in an integrated system with solar PV
- for baseline battery costs and large-size residential customers in most NEM states, the payback periods for newly installed storage and solar PV systems on a TOU tariff decline over the projection period, from 11–35 years in 2015 to 6–12 years by 2035
- for baseline battery costs and large-size residential customers in most NEM states, the payback periods for newly installed storage and solar PV systems on a flat tariff decline over the projection period, from 9–12 years in 2015 to 4–6 years by 2035
- for households without solar PV, battery storage under TOU tariff pricing provides the most value to households, particularly in New South Wales
- for baseline battery costs and large-size customers in most NEM states, the payback periods for battery storage for households without PV on a TOU tariff decline over the projection period, from 17–35 years in 2015 to 8–11 years by 2035
- for households with solar PV already installed, battery storage does not provide significant additional benefits under flat tariff or TOU pricing
- there is greater value of storage for households with large loads than for those with small loads
- battery storage under capacity pricing appears to be unviable for households based on the tariff structure that has been assumed
- lower battery costs in the future reduce the payback period by 4–5 years for most time periods if battery systems are installed under TOU pricing.

5.4 Generation investor

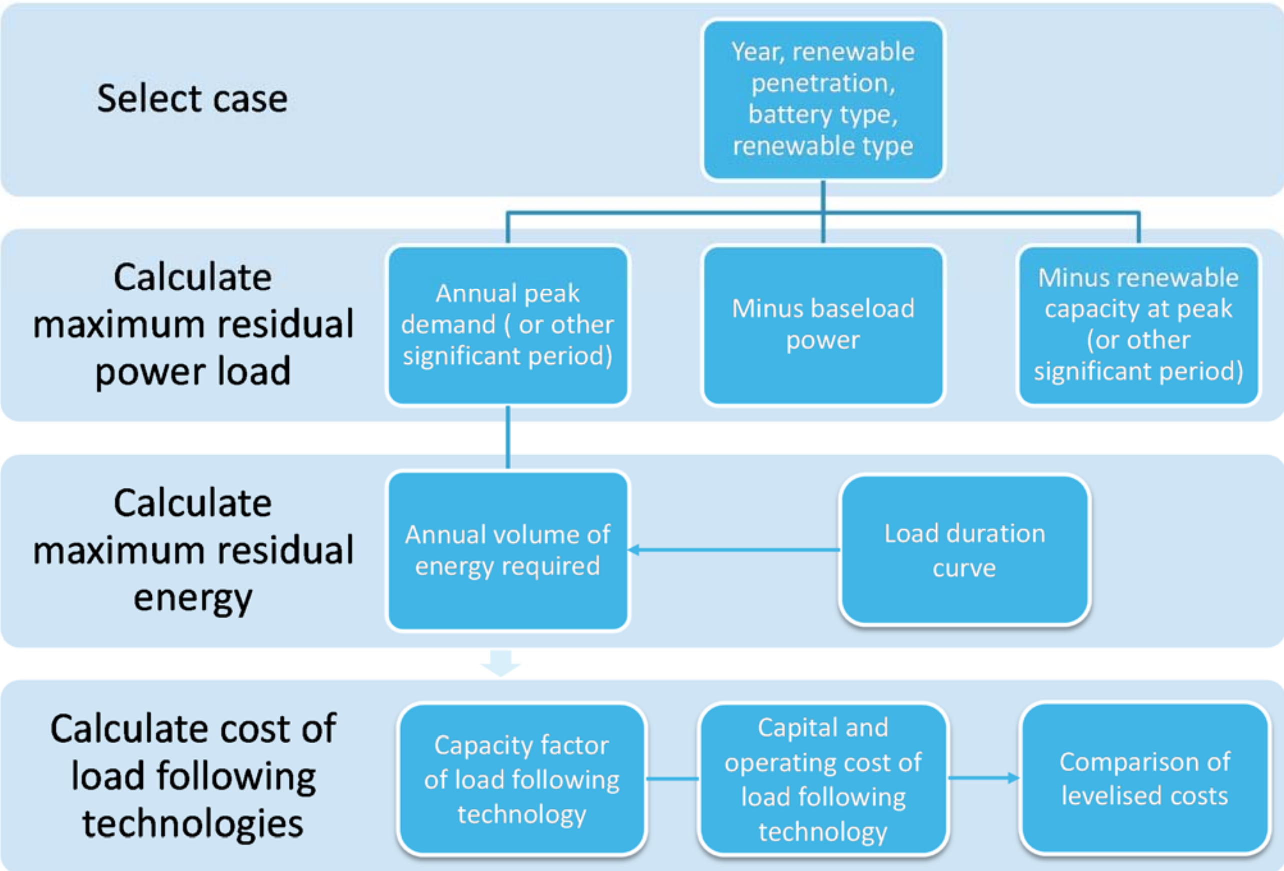
This section explores the economic viability of using batteries to participate in the NEM. The market operates as an automated dispatch algorithm to determine the least cost set of generation bids required to meet demand. In this context, batteries could operate as both a large-scale consumer (during the charge phase) and a generation unit (during the discharge phase).

The NEM accommodates several types of technologies with different generation capabilities. Coal-fired generators usually provide the bulk of power and operate on a more or less continuous basis – this is called baseload power. Gas and some under-used coal-fired power plants also provide power less frequently as the load increases during ‘shoulder’ and ‘peak’ periods of the day, which vary by season. Gas peaking plants specialise in being able to provide power only on a small number of days of very high peak demand. Their competitive advantage in this role lies in two important characteristics. First, they have the lowest capital cost of all the available generation options. This is a necessary characteristic because the capital will have poor utilisation. Second, gas peaking plants are able to start quickly from zero power output.

We examine the economic viability of batteries competing against gas peaking plants because this is the largest opportunity for batteries to take part in the NEM. Batteries could also participate in providing frequency control and other ancillary services; however, these opportunities are much smaller.[7]

5.4.1 Overview of methodology

A battery facility that is large enough to be eligible as an NEM participant (e.g. > 30 MW capacity) could derive its revenue directly from the wholesale market bidding process. It could also be contracted to a retailer as a means for the retailer to reduce its exposure to high prices associated with peak periods. We did not examine these revenue streams directly. Rather, our approach to establishing whether batteries could be economically viable only compared the cost of batteries versus gas peaking plant when providing similar services. Figure 35 shows the steps taken to implement the methodology. The following sections provide detail on each step and present the results.



[7] Currently the total volume of trading across all eight Frequency Control and Ancillary Services (FCAS) commodities is only approximately 1% of the total purchases of energy in the NEM. Although it is a small part of generator revenue, it is possible that, as the share of intermittent renewable electricity generation increases, this percentage may increase.

Figure 35: Overview of methodology

5.4.2 Selecting the cases to be examined

The analysis described here focused on the snapshot years of 2025 and 2035 as the comparison point for costs, rather than providing a timeline for 2015–2035. This is because excess generation capacity in the NEM means that new load-following capacity, batteries or otherwise, will probably only be relevant in the latter half of the projection period, when new capacity is more likely to find a market. We sourced demand in the years 2025 and 2035 from the *Future Grid Forum Scenario 2: Rise of the prosumer* [97]. Within this NEM demand context, we explored the following cases:

- *Four NEM states* – Our analysis included only New South Wales, Queensland, South Australia and Victoria. Given the availability of hydro power capacity in Tasmania, the market for other load-following technologies in that state is not significant.
- *Two renewable penetration levels* – We included 40% and 60% of electricity generation by state (inclusive of existing hydro power) to cover the plausible range by 2035. Due to the existing hydro renewable generation capacity, the effective share of non-hydro renewables is around 5% lower in New South Wales and Victoria. Also, South Australia has already achieved the lowest case of 40%.
- *Four battery technologies* – The technologies were lead acid, Li-ion, molten salt and flow batteries, as discussed in Part I.
- *Two renewable technologies* – Onshore wind and solar PV were combined in equal proportions. For simplicity and in recognition of their positon as lowest cost among the intermittent renewable technologies available, these were chosen as the intermittent technologies most likely to be deployed at significant scale.

5.4.3 Calculating the maximum residual load that must be supplied

To estimate the cost of the gas peaking plants and battery technologies, it is necessary to first set out what load they will need to supply. This is determined by subtracting baseload and renewable supply from the total demand load, to give the residual load that must be met by load-following technologies. Ideally, this subtraction would be carried out on a five-minute to half-hourly basis (consistent with NEM dispatch operation) over the life of the technologies. This would determine the entire operating schedule for the technologies and would allow us to optimise for the type of battery best suited to that schedule and, in the case of gas peaking plants, the size and combination of plants to be deployed. However, this type of temporally disaggregated data analysis and optimisation was considered too detailed for the scope of this study; therefore, an alternative method was developed.

The alternative method is more approximate. It involves first calculating the maximum residual load at the annual peak demand in each state in 2035, by subtracting baseload power and expected renewable load at the annual peak demand. The aim was to attempt to discover the maximum load throughout the entire year that might need to be met by the load-following technology. This establishes the maximum capacity, in watts, of load-following plant that must be deployed.[8]

The power supplied by renewables at the peak demand was estimated by drawing on the historical record. The AEMO published a set of renewable energy capacity factors covering the period from 2003 to 2012 but with some gaps in some years, depending on the renewable energy source [98]. For simplicity, we took the capacity at peak for 2009–10 (or for 2010–11 if not otherwise available).

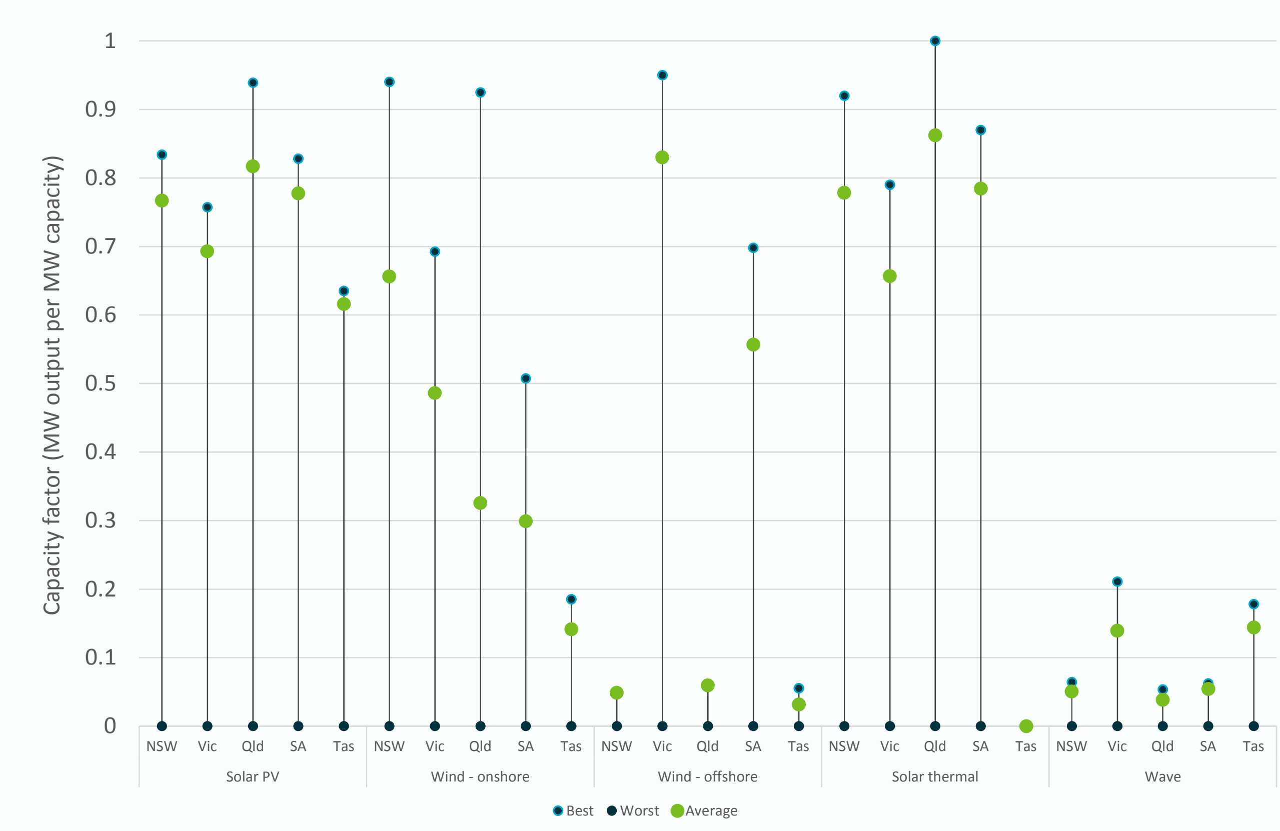


Figure 36: Capacity factor at the annual peak demand event (2009–10 or 2010–11) for five renewable technologies: best, worst and average across a 43 polygons map of the NEM states

NEM, National Electricity Market; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

This dataset provides a capacity factor for each hour of the year for five intermittent renewable technologies across a map of the NEM, which is divided into 43 polygons. Figure 36 shows the best, worst and average capacity factor across each state's relevant polygons at the peak demand event for either 2009–10 or 2010–11. Apart from Tasmania, where the peak occurred on a winter morning or evening (depending on the year), the peaks occurred between 2 pm and 6 pm on a January or February summer day. Given this timing, it is no surprise that the capacity factor for solar technologies in those states is high.

However, the timing and size of peaks in the NEM is changing because of the adoption of renewable electricity generation technologies at both the generation and consumption ends of

[8] In practice, a system would probably ensure that there is another 5% capacity above peak as a redundancy. However, given that we ignored the potential to import generation from other states to meet peak demand, we did not add this factor.

the grid. Because some renewables are incapable of controlling the timing of their output (rather, their output follows local weather conditions), their impact on generation is much the same as on demand. That is, their generation can be viewed as negative demand, which creates a new demand signal: demand net of renewable output. It is demand net of renewable output that the remaining flexible generation plant must follow.

At the generation end, the high adoption of wind power, particularly in South Australia, means that peaks in demand net of renewable output could occur at traditional times (e.g. in the morning and afternoon or evening), reflecting peaks in consumers' use of electrical appliances. Alternatively, they could be uncorrelated with these activities and reflect times when wind speeds are poor.

At the consumption end of the grid, demand net of renewables is impacted by the adoption of residential and commercial solar PV panels (found in all states, but strongest in South Australia and Queensland). The impact of solar panels is to decrease net demand in the middle of the day. This could shift the net peak demand event of the year into the evening rather than mid to late afternoon.

Given these potential changes, we made one adjustment to individual renewable energy capacity factors. We took the historical peak day used to calculate renewable capacity at peak and assumed that the peak occurred at 8 pm rather than earlier in the day. This effectively shifts the solar PV capacity at peak to zero, which is a plausible outcome without storage. On the basis of these adjustments, the assumed renewable capacity combining equal proportions of solar PV and wind at the annual peak demand was 0.33 for New South Wales, 0.24 for Victoria, 0.16 for Queensland and 0.15 for South Australia.

5.4.4 Calculating the maximum residual energy that must be supplied

To calculate the cost of the load-following technologies, we also need to know how much energy they need to supply in the year 2035. It is not possible to calculate this directly. Instead, we took our previous analysis of the residual load and matched that to a load duration curve to determine how often, in a typical year, the load-following technology would be operating. A load duration curve is a way of presenting annual load data to show the percentage of time that a level of load is reached in a year. Typically, the final 10% of load occurs for only 1–2% of the year, the next 10% only around 10–15% of the time, and so forth. We applied a load duration curve to determine how often our load-following technology was operating and, therefore, the energy it supplied in a year. The amount differs by state but increases with the renewable penetration. At the lower range of renewable penetration, and if there is already significant hydro capacity, the load-following plant rarely operates, with capacity factors below 10%. Where there is high-level renewable penetration in a state with little hydro capacity, the load-following technology capacity factor can be as high as 40%.

5.4.5 Comparison of levelised costs of electricity for load-following technologies

Using the battery and inverter technology cost and technical performance data from Part I of this report and gas peaking plant costs from [99, 100], we calculated and compared the levelised cost of electricity for these load-following technologies if deployed in 2025 and 2035 at the two renewable penetration levels of 40% and 60% (2035 only).

For the operating costs of gas peaking plant, we applied the 2025 and 2035 cost of gas fuel based on the low case presented in [101], given that oil prices have fallen since those data were published; fuel efficiencies were sourced from [100]. For batteries, we assumed that they purchase electricity during charging at the long-run marginal cost of coal-fired power in their state. Based on these assumptions, the levelised cost of gas peaking plant and five battery technologies are shown for 2025 in Figure 37 and for 2035 in Figure 38 and Figure 39.

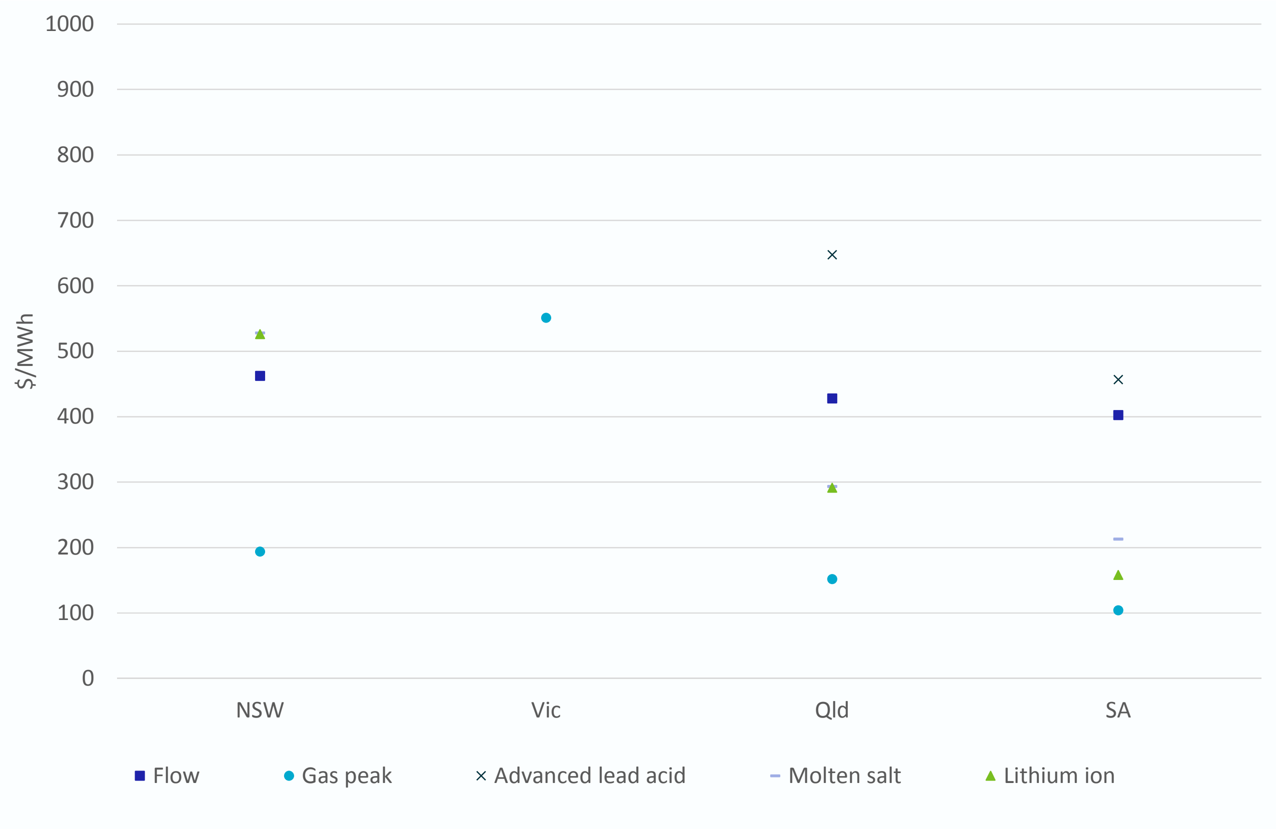


Figure 37: Levelised cost of electricity for selected load-following technologies at 40% renewable penetration in 2025

NSW, New South Wales; Qld, Queensland; SA, South Australia; Vic, Victoria

In 2025, at 40% renewable penetration, the analysis shows that the levelised cost of electricity is highest in Victoria followed by New South Wales since all load-following technologies would have the poorest utilisation. This is because both states have existing hydropower capacity, and the combined capacity factor of the wind and solar technologies at peak is reasonably good (around twice that of the other states). The utilisation is poorest (< 5%) in Victoria, where the residual load that needs to be met by load-following plant is small. In Queensland and South Australia, the load-following technologies have utilisation rates above 10%, and consequently a lower levelised cost of electricity for those plants.

Battery technologies are least competitive with gas peaking in high power, very low energy (low utilisation) applications. In the worst case, in Victoria, all battery costs are above $1000/MWh. As utilisation improves, battery and gas peaking costs converge (i.e. in South Australia and Queensland), with Lithium ion followed by Molten salt being most competitive. Flow battery costs are the best suited to higher power low utilisation applications (i.e. higher power capacity, low number of charge-discharge cycles). However, as utilisation increases their relatively low maximum cycle life decreases the period over which the battery costs can be amortised, increasing costs relative to the other batteries. Advanced lead acid batteries costs are generally higher due a low depth of discharge (more batteries are required to meet the same power and energy requirements as other batteries).. In Figure 38, by 2035, at 40% renewable penetration, battery costs have reduced and are now competitive with gas in some states.

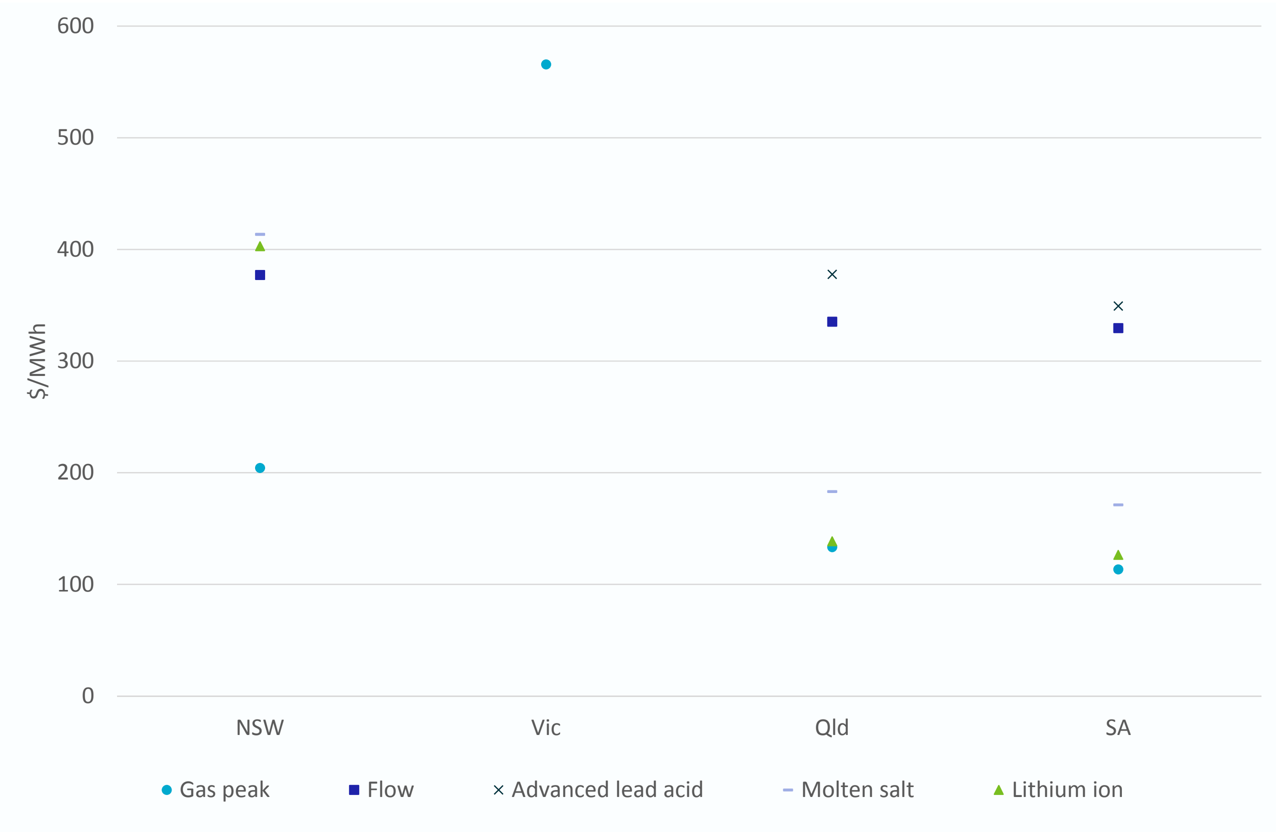


Figure 38: Levelised cost of electricity for selected load-following technologies at 40% renewable penetration in 2035

NSW, New South Wales; Qld, Queensland; SA, South Australia; Vic, Victoria

Increasing the renewable penetration up to 60% was sufficient to shift Victoria's load following capacity requirements into a higher utilisation bracket but not so the other states as they are already on a flatter part of the load duration curve. Consequently the utilisation and cost of load-following plant is now similar to that of New South Wales.

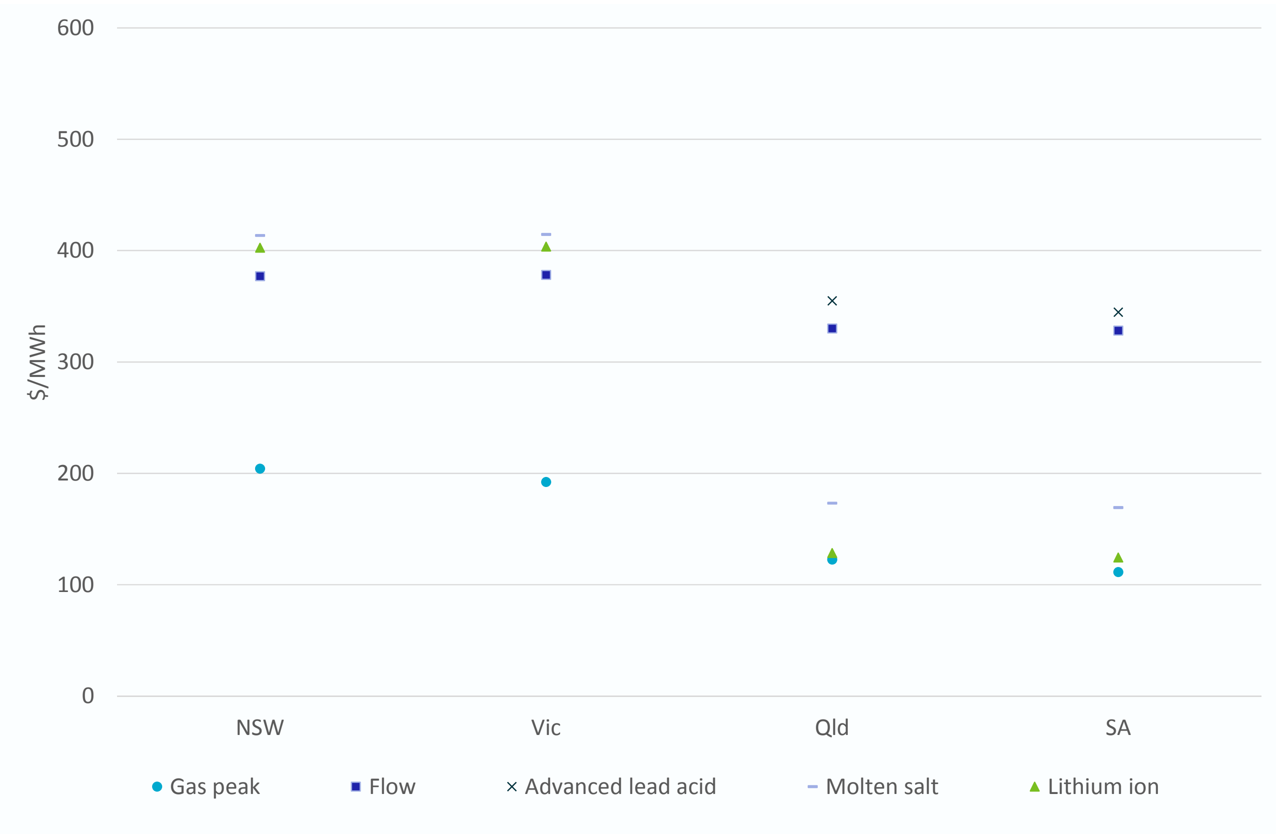


Figure 39: Levelised cost of electricity for selected load-following technologies at 60% renewable penetration in 2035

NSW, New South Wales; Qld, Queensland; SA, South Australia; Vic, Victoria

5.4.6 Conclusions

The levelised cost of electricity analysis suggests that batteries could compete with gas peaking plant in some NEM states to provide load-following services from 2035. Queensland and South Australia would be the strongest candidates due to their lack of existing hydro capacity and data indicates their renewables have lower output at peak demand. Tasmania would be least attractive due to large existing hydro capacity.

The main limitation of this analysis is that the calculations to determine the power and energy that the battery and gas peaking plant had to meet were developed using approximate techniques that were necessary given the scope. The calculations could be made more accurate by using approaches that are more data intensive and temporally disaggregated. This is a gap for future research to fill. Some further issues that might be considered in future studies are:

- changes in battery performance over time
- alternative demand scenarios
- alternative electricity generation mixes, including additional types of intermittent renewable technologies
- additional battery and gas price projections.

5.5 Electric vehicle applications

EVs have been available for sale in Australia for a number of years as dedicated or retrofitted models. This analysis examined whether EVs may become an economically viable vehicle choice and, if so, under what circumstances. The analysis compared the whole-of-cost of travel in cents per kilometre of two EV types across three vehicle size ranges with vehicles of equivalent size using a petrol-fuelled internal combustion engine (ICE) only.

The whole-of-cost of travel means that all of the upfront capital costs (or amortised annual loan repayments), annual insurance and registration, and weekly fuel running costs are converted to the common measure of cost per kilometre. We amortised the vehicle cost over 5 years because this is the length of a typical car loan.[9] For simplicity, we did not take into account resale or scrap value; this is an assumption in favour of EVs, initially, because resale value may be low until EVs become more widely accepted. We also did not take account of battery replacement. However, given that battery life would appear to be up to 10 years and most internal combustion vehicles require major work at or before this time, this is not considered a bias in either direction.

The two types of EV considered were:

- battery EV (BEV) – a vehicle that uses solely electricity stored in batteries and an electric motor in place of an ICE and liquid petroleum fuel tank; assumed battery range is 125 km (although product offerings will vary)
- plug-in hybrid EV (PHEV) – a hybrid vehicle that draws electricity from the grid to charge the batteries as the primary source of power, but also includes an on-board ICE to either supplement or recharge the battery when it becomes depleted in journeys beyond the range of the battery; assumed battery range is 50 km (although product offerings will vary).

5.5.1 Vehicle costs

Following the vehicle disaggregation used in CSIRO's Energy Sector Model (ESM), described in [102, 103], which also give applications, we assumed three types of passenger vehicle classes: small, medium and heavy,[10] with average prices of $14 000, $21 000 and $41 000, respectively, for petrol ICE vehicle models.

For a BEV model, we used $39 990 as the starting price based on a Nissan Leaf, and place this in the small vehicle category given its size. Thus, as a starting point, we can say that a BEV currently costs $25 990 more than the equivalent petrol vehicle. An electric vehicle also needs a home charging station installed, at a cost of about $1200. If the electrical system of the home needs to be amended to add a significant new load, then the additional electrical work needed could cost several thousand dollars. Whatever the final amount, on the basis of the vehicle alone it would take more than a decade of fuel savings to pay back the additional upfront cost of a BEV.

However, there are good reasons to expect the additional upfront costs of a BEV to fall in the long run. First, as discussed in Part I, battery costs are expected to fall. Second, EV manufacturing is yet to scale up and therefore has not yet achieved economies of scale. An efficient vehicle

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[9] In practice, some owners may redraw from their home loan and some may sell their vehicle before the end of the 5-year period, so 5 years is a mid-range estimate rather than a hard rule.

[10] Although these vehicles classes are designed initially around weights, when we compare to EVs we do not strictly require EVs to be the same weight; rather we consider a vehicle of similar size to be competing with that weight class for a vehicle with an internal combustion engine.

manufacturing scale is generally in the several hundreds of thousands. Around 300 000 EVs were manufactured in 2014 [104] across more than 20 models; thus, none of them were manufactured at efficient scale.

Working back from what the batteries should cost under ideal manufacturing conditions plus the base cost of an ICE vehicle, we can get a sense of what cost-efficient vehicle manufacturing should deliver. An EV drive train is unique and its long-term cost is unknown. However, we do know that it will have an order of magnitude fewer parts than the ICE vehicle engine drive train. The most expensive item in an EV is the batteries. If we assume a small vehicle BEV efficiency of 0.2 kWh/km, a 125 km range and a battery cost of $350/kWh [14], then the cost of batteries is $8250. If we also assume that the remainder of the BEV drive train costs no more than that of an ICE vehicle, then the long-term cost of a small BEV manufactured at efficient scale – assuming no improvement in battery costs or fuel efficiency – should be $14 000 + $8250 = $22 250. This is $17 740 less than the current BEV price.

To create a future trajectory of BEVs, we assumed this penalty for not yet achieving economies of scale is slowly overcome such that it declines to zero by 2032 (based on a 15% reduction per annum from 2015). In fact, the penalty becomes slightly negative, reflecting the view that the low number of components in a BEV, compared to an ICE vehicle, should allow for a slight reduction in the cost of the vehicle drive train.

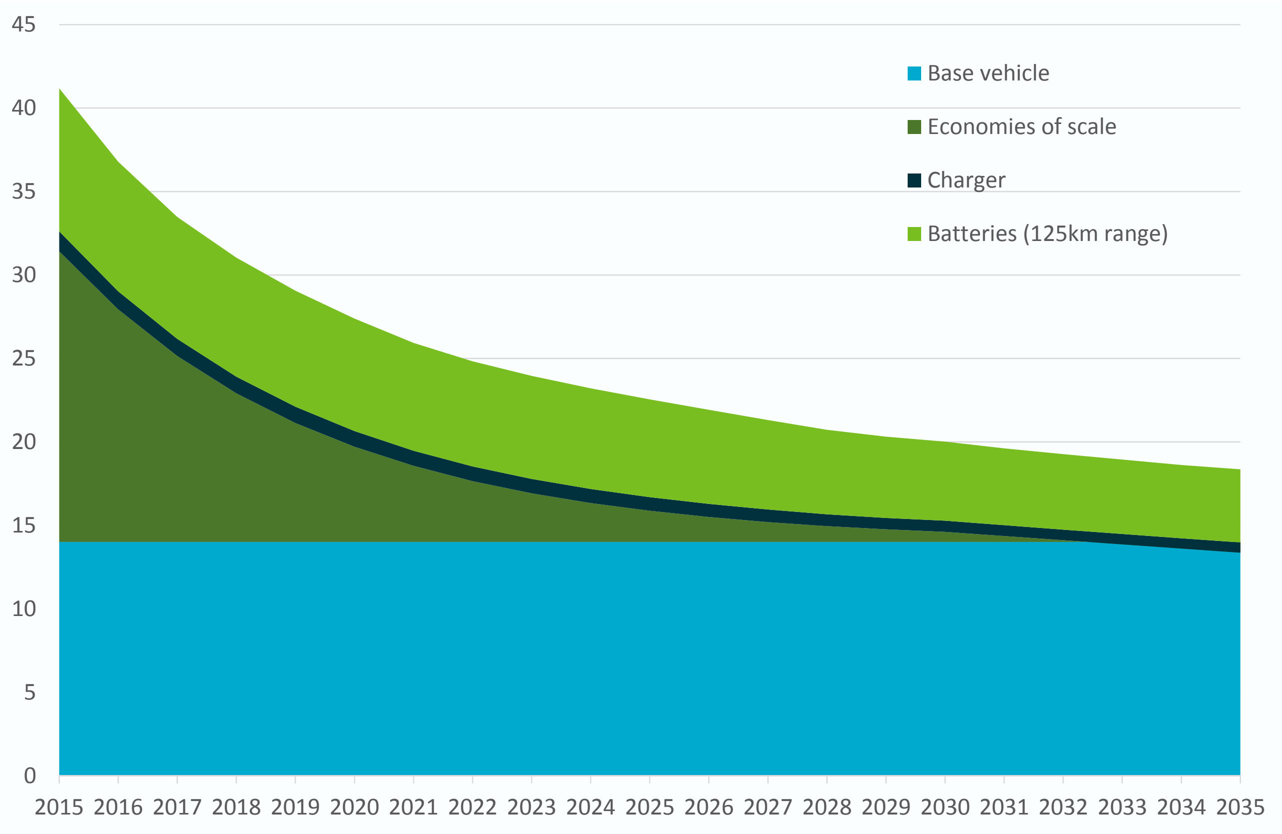

Figure 40: Assumed changes in cost components of light battery electric vehicles

The other components, already discussed, are the batteries and the charging unit; these are added to the cost and projected in Figure 40 for a small-size vehicle. For other vehicles sizes, for both BEVs and PHEVs, we followed the same methodology except that, since only a few representative vehicles are available, we assumed the premium for not having reached economies of scale is similar to that of the small BEV, but scaled up according to the relative cost of the base vehicle size. For PHEVs, there were three differences in the approach. The first is that we did not include a light version of that vehicle class since it will be less practical to include two engine types in a light vehicle. The second is that we assumed that PHEVs have only a 50 km range on batteries alone and therefore that their total battery costs are lower. Finally, we assumed the premium for not having reached economies of scale reduces to zero but does not fall below zero, given that a PHEV includes all the ICE vehicle components and therefore will not achieve the same drive chain cost reductions as a BEV. A summary of the costs by vehicle type is shown in Table 22.

Table 22: Costs by vehicle type in $'000

	BEV			PHEV		
	2015	**2025**	**2035**	**2015**	**2025**	**2035**
Small	41	23	18	NA	NA	NA
Medium	67	36	29	61	32	28
Heavy	106	56	46	98	51	44

BEV, battery electric vehicle; NA, not applicable; PHEV, plug-in hybrid electric vehicle

5.5.2 Fuel costs

Liquid fuel

An important component of the running costs for an ICE vehicle is the fuel price. The selection of suitable oil price projections is difficult because of the present uncertainty in the oil market, following a deep reduction in oil prices at the end of 2014. Most of the projections available before that do not take into account the impact of that fall. In particular, we would normally choose to apply the forecasts from the International Energy Agency (IEA), since that is the only reputable group routinely incorporating the impact of increasing action on climate change on the world oil price (most other projections are based on a framework of no action or current policies). Instead, given that the IEA [32] oil and gas projections are out of date, we applied the EIA [105] projections and reduced them slightly to make them more consistent with the IEA's methodology, as shown in Figure 41.

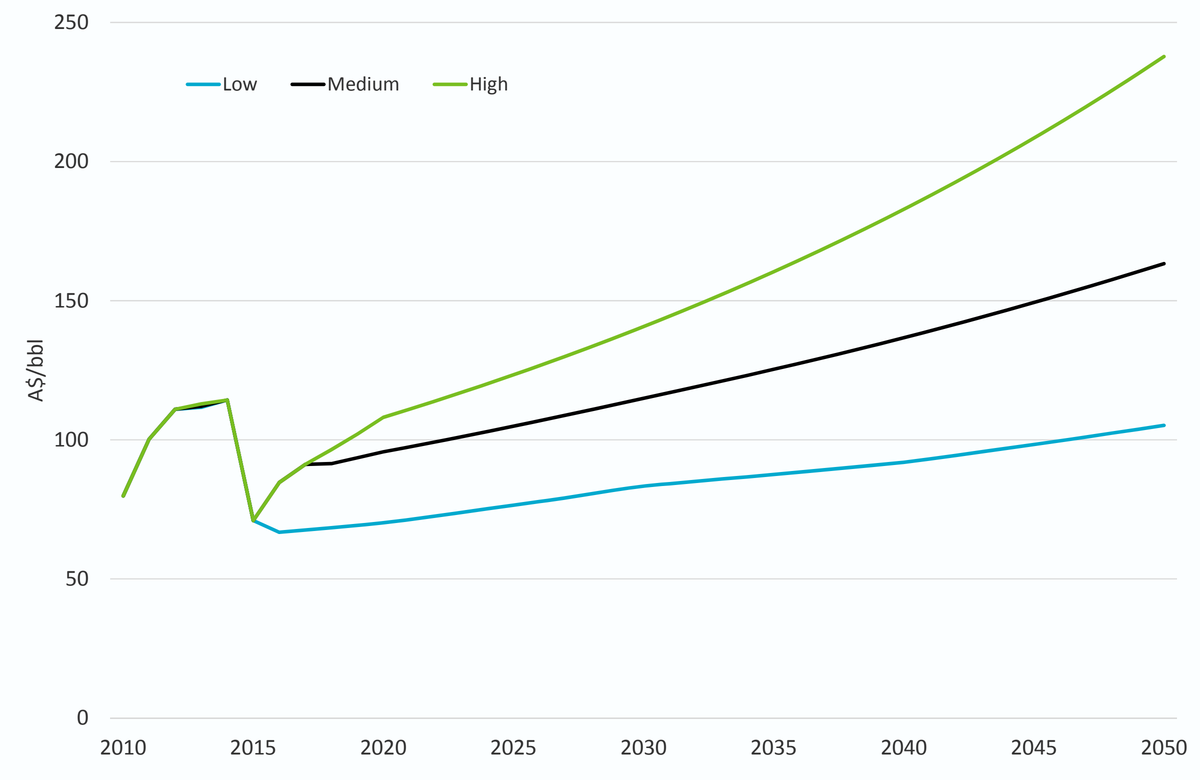

Figure 41: Assumed oil price projections

The oil price was converted to a petrol price via the methodology described in [106], and an assumed convergence towards a long-term exchange rate of 0.75 A$/US$ (Figure 42).

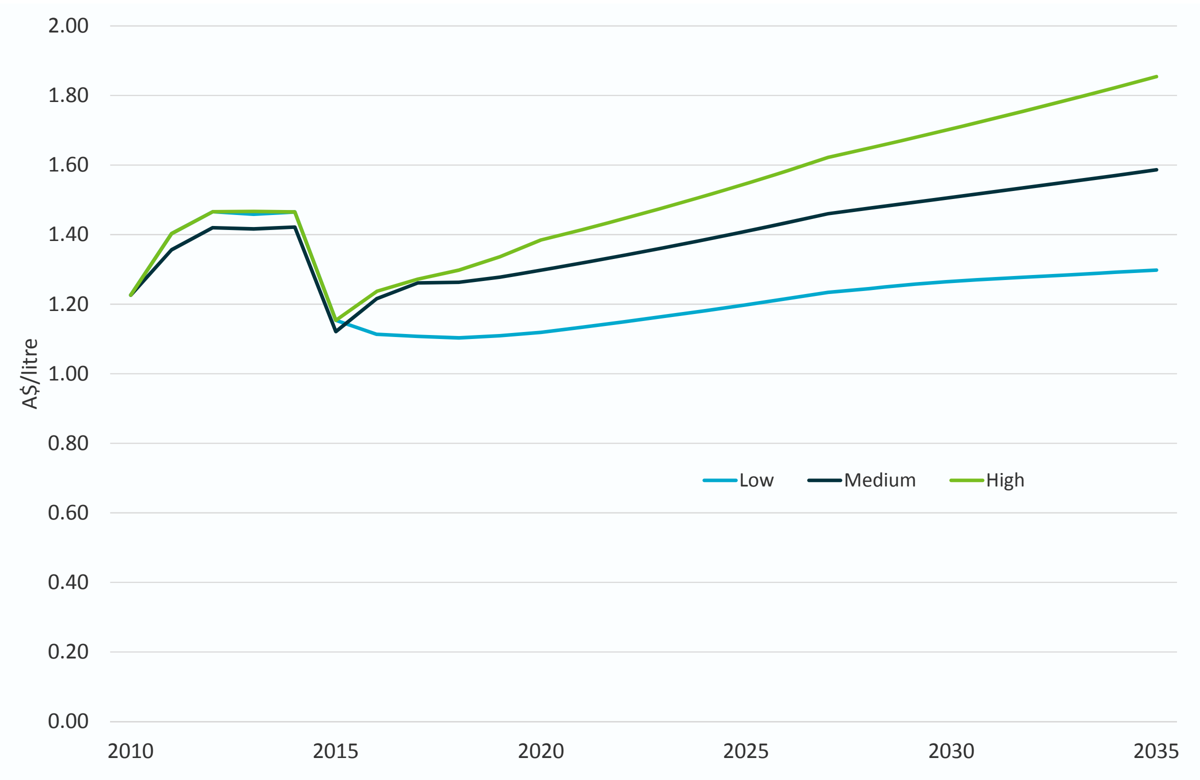

Figure 42: Projections of low, medium and high real Australian petrol prices

Determining the fuel costs requires an assumption about the fuel efficiency of petrol ICE vehicles. The average new vehicle fuel efficiency is around 7.7 L/100 km [107], with considerable variation around that average because of the range of car sizes. We assumed that this improves at an average rate of 1.3% based on an assumed slowing of recent trends as oil price pressure eases. We did not include any potential for partial electrification or hybridisation of the ICE vehicle.

The number of kilometres travelled each year is also important in determining fuel costs. The average distance is just under 15 000 km per annum [108]. We also explored distances of 10 000 and 20 000 km given that distance travelled varies considerably between vehicle owners.

Electricity fuel

The fuel efficiency of the electric drive train is assumed to be 0.2 kWh/km for small vehicles, 0.22 kWh/km for medium vehicles and 0.35 kWh/km for heavy vehicles. The projected cost of residential electricity supply was taken from the average of the Future Grid Forum scenarios [97], which are shown in Figure 43. For the period of interest (up to 2035), there was not a large difference between the Future Grid Forum residential retail electricity prices – the exception being perhaps Scenario 4, which assumes very strong greenhouse gas abatement action; however, even then, the differences only emerge from 2033 onwards.

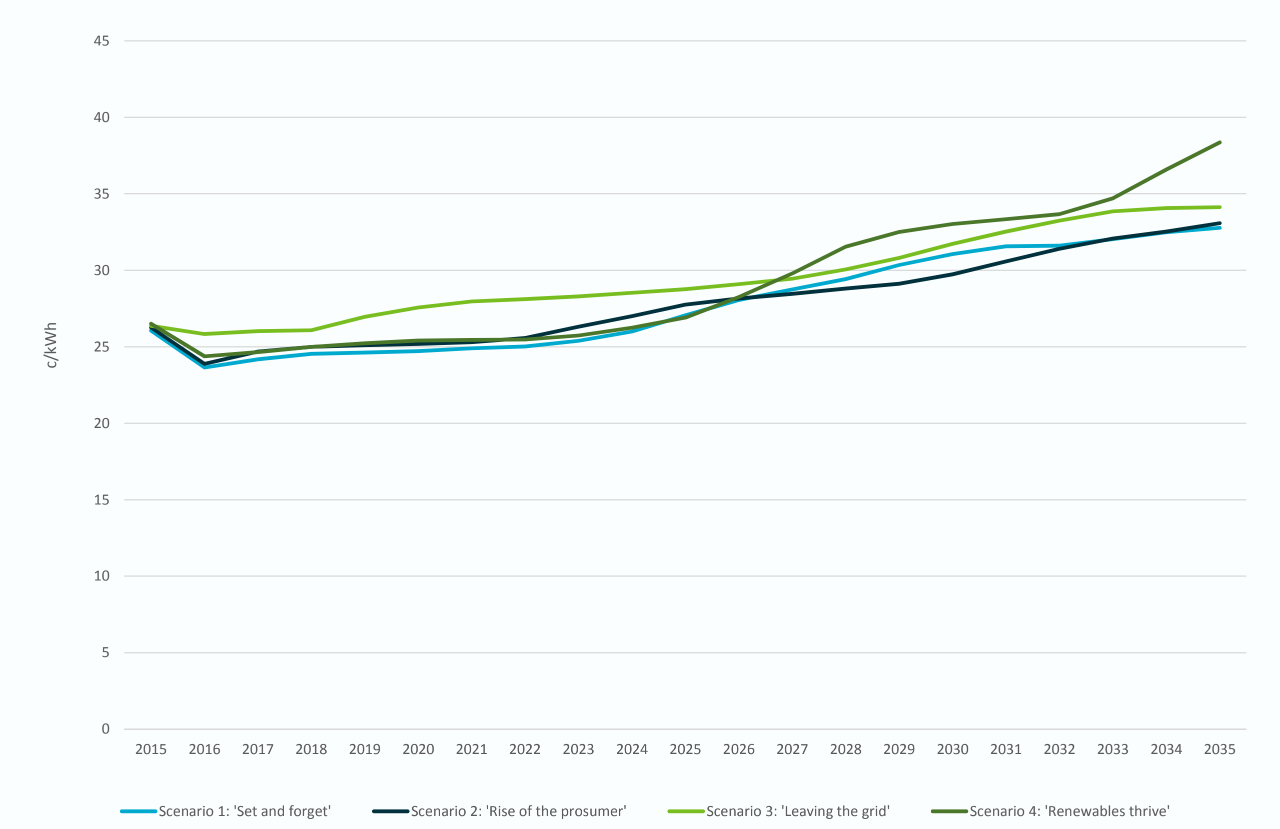

Figure 43: Projected residential retail electricity prices from the Future Grid Forum

These findings are based on flat volume tariff prices, and owners of EVs will probably explore different tariff structures that minimise their cost of charging. It is difficult to identify what a future discount might be for charging at night. At present, the discount for off-peak hot water heating can be around 60% of the normal rate and occurs at night. TOU tariffs also offer similar off-peak rates. Both of these would be ideal, since the average user travelling 15 000 km/year (i.e. 40 km/day) would only need to recharge around 9 kWh (after losses). This could be achieved, for example, within a 4.5 hour period using a 2 kW charger – so there is probably not much need to charge outside of off-peak periods unless the vehicle has been driven unusually far on a particular day. Faster charges may also be an option.

It is not clear that the off-peak price differential and the off-peak time will remain the same. Increasing penetration of EVs and other storage devices could erode the incentives to offer such a large discount at night. Also, if generation becomes dominated by solar power, which is growing rapidly at present, then it could be that the off-peak period shifts to the day. Given these uncertainties, we assumed a reduced off-peak discount of 40%. However, we assumed that charging at night is still the norm.

Comparison of electricity and liquid fuel costs

Based on the fuel cost assumptions for both petrol-consuming and electricity-consuming vehicles discussed above, Figure 44 compares the projected annual fuel consumption costs for medium-size vehicles. The figure shows that the fuel costs for an ICE vehicle are generally four times higher than those for an EV, with a slight improvement projected over time due to ICE fuel efficiency improvements slightly more than offsetting growth in petrol prices. The approximately $1100–$1200 in annual fuel savings that a BEV provides or the $700–$800 that a PHEV provides is the means by which an owner can hope to pay back the higher upfront (or vehicle loan) costs associated with these vehicles, discussed in the next section.

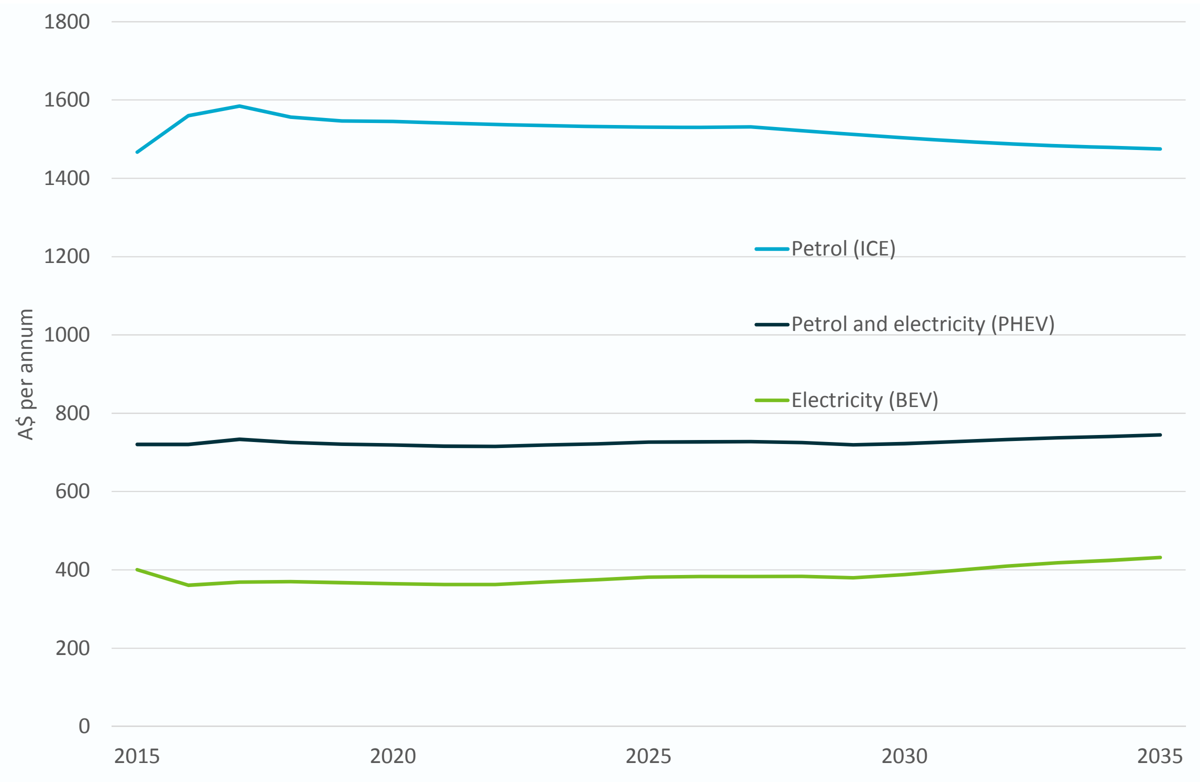

Figure 44: Projected annual fuel costs by vehicle engine type to 2035 for a medium-size vehicle, at medium oil prices and travelling 15 000 km per year

BEV, battery electric vehicle; ICE, internal combustion engine; PHEV, plug-in hybrid electric vehicle

5.5.3 Discounted payback period

We projected the discounted payback period for BEVs and PHEVs for three annual travel distances, three vehicle sizes and three oil price projections. However, to avoid plotting too many results, we plotted only the following cases for each vehicle size:

- medium case: medium oil prices and 15 000 km annual travel distance
- best case: high oil prices and 20 000 km annual travel distance

- worst case: low oil prices and 10 000 km annual travel distance.

The best case is anything that makes using an ICE relatively more expensive to run (i.e. high oil prices and longer annual travelling distances), whereas the worst case is the opposite.

BEV results

The BEV payback period results for small, medium and heavy vehicle classes are shown in Figures 45–47. They show that the vehicle currently cannot be paid back on a discounted basis. However, as the cost of BEVs declines, the payback period steadily declines until, by 2026, the payback period is under 10 years in the medium case. In the best case, the payback period is under 10 years by 2021 and under 5 years by 2028. In the worst case, a 10-year payback period is outside the projection period, beyond 2035.

Across the vehicle sizes, in the 2020s, the small vehicle class is the most attractive BEV in terms of payback period. However, by the end of the projection period, the vehicle class does not matter. This is because, initially, the higher cost of BEVs is a proportionally greater burden on larger vehicle classes. However, as the cost premium for BEVs is reduced, larger vehicles achieve equal or slightly better payback periods (since larger vehicles use more fuel they can achieve greater fuel savings by using lower cost electricity).

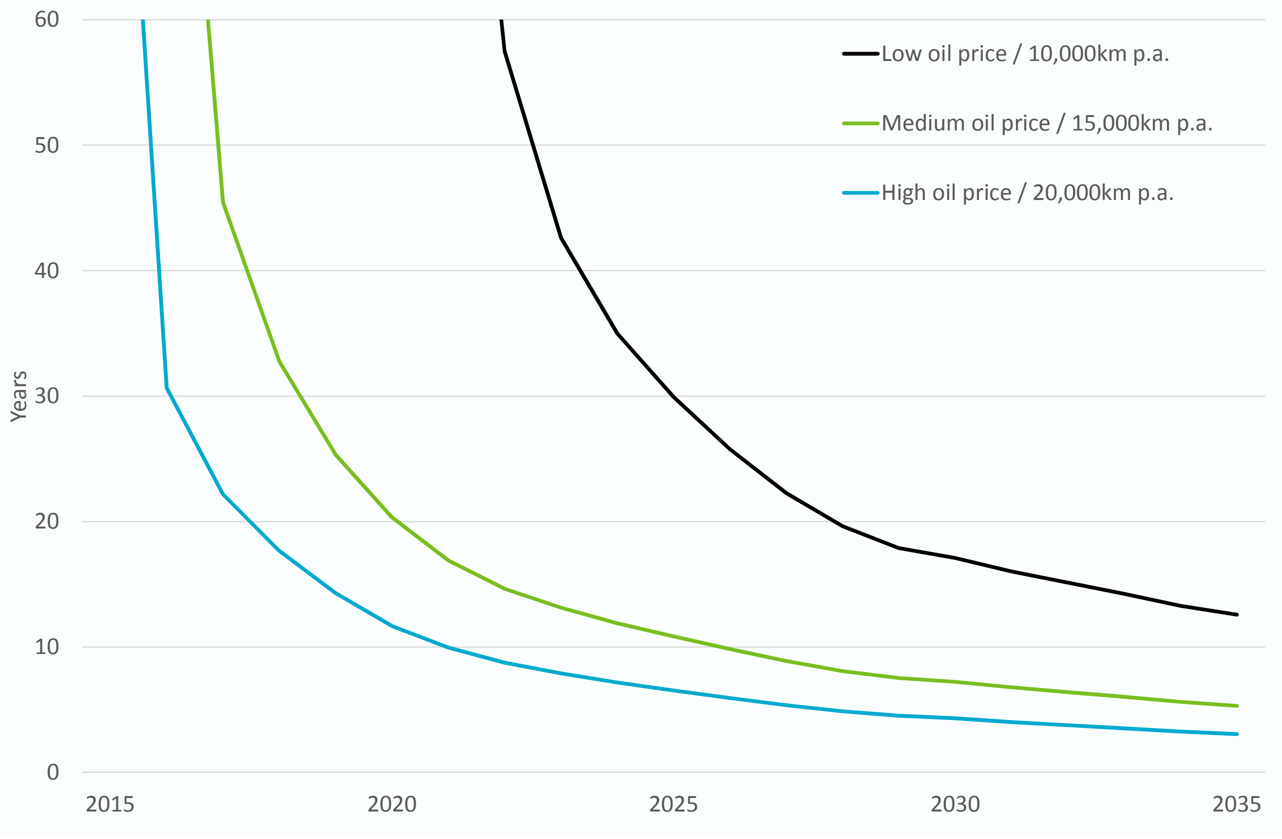

Figure 45: Discounted payback period to 2035 for light vehicle class BEV

BEV, battery electric vehicle

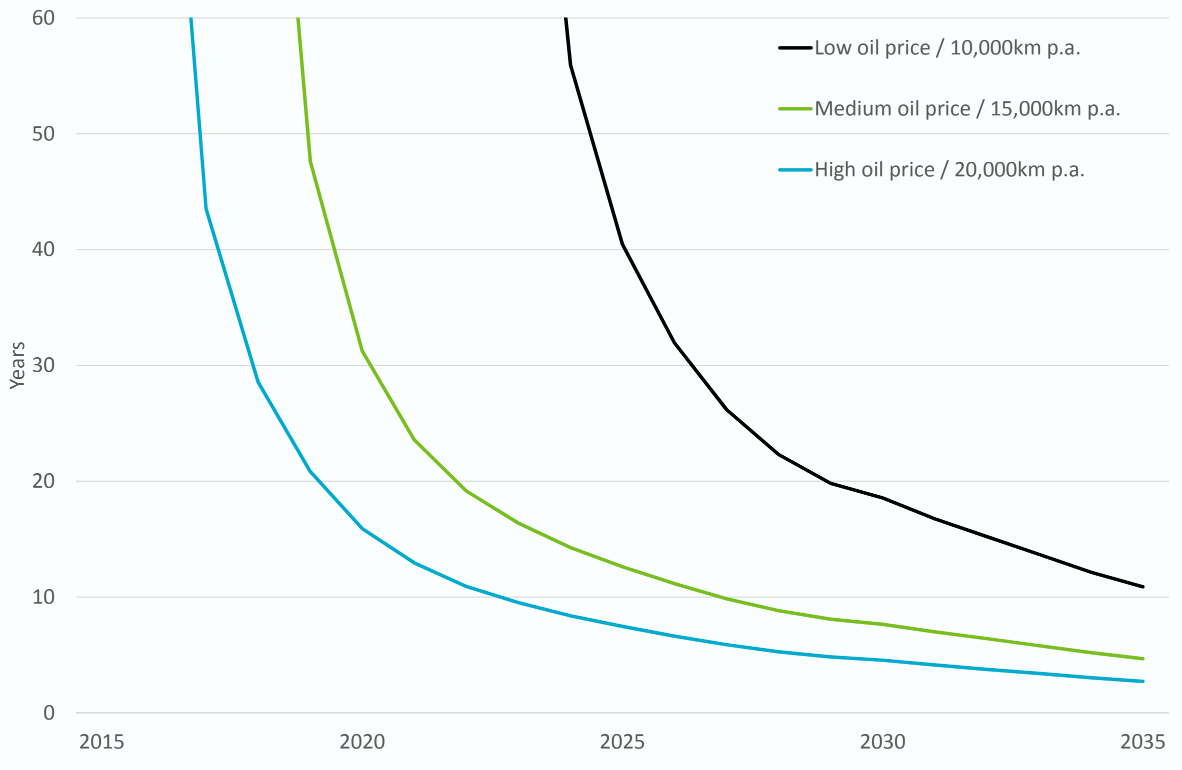

Figure 46: Discounted payback period to 2035 for medium vehicle class BEV

BEV, battery electric vehicle

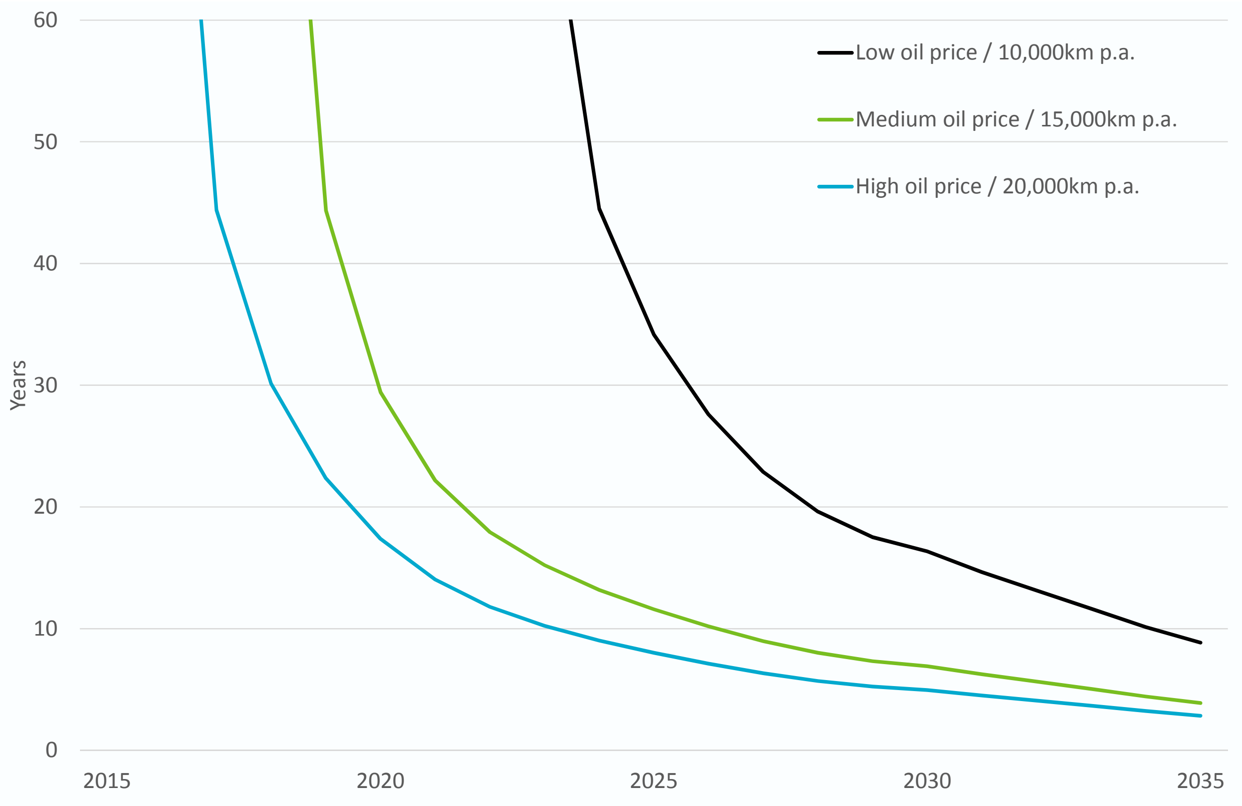

Figure 47: Discounted payback period to 2035 for heavy vehicle class BEV

BEV, battery electric vehicle

PHEV results

The discounted payback period for PHEVs for the medium and large vehicle classes is shown in Figure 48 and Figure 49, respectively. As with the BEVs, the PHEVs do not pay back the additional upfront cost of the vehicle when purchased in 2015. Compared to BEVs, the fuel savings are less but the vehicle cost premium is fairly similar (as discussed earlier in relation to vehicle costs, some of the premium is not battery costs, which are lower for PHEVs, but rather manufacturing scale inefficiencies).

As PHEV costs improve over time, these vehicles catch up fairly rapidly, and by 2035 they offer a fairly similar or even slightly better payback period. The insight this provides is that, once BEVs and PHEVs achieve scale efficiencies, consumers would do well to choose the size of their battery carefully. At 125 km, the battery size for a BEV is not well optimised for those who only ever travel 40 km per day. Accordingly, such consumers could consider getting a smaller battery pack for their BEV or could choose a PHEV instead. Of course, these choices are more complicated if they sometimes need to be able to travel longer distances (i.e. is the vehicle a second car for commuting only, must it also have long-range capability, can they use a rental car when necessary or do they have other options?).

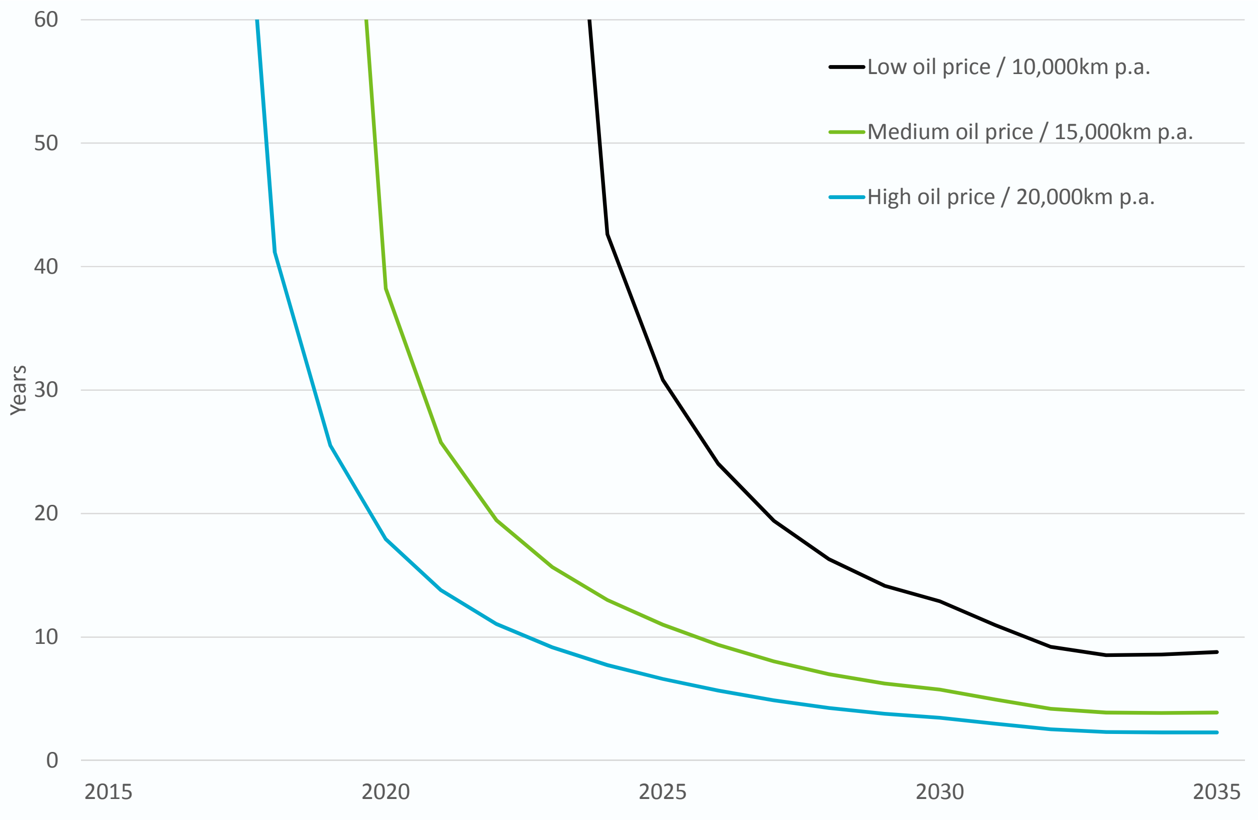

Figure 48: Discounted payback period to 2035 for medium vehicle class PHEV

PHEV, plug-in hybrid electric vehicle

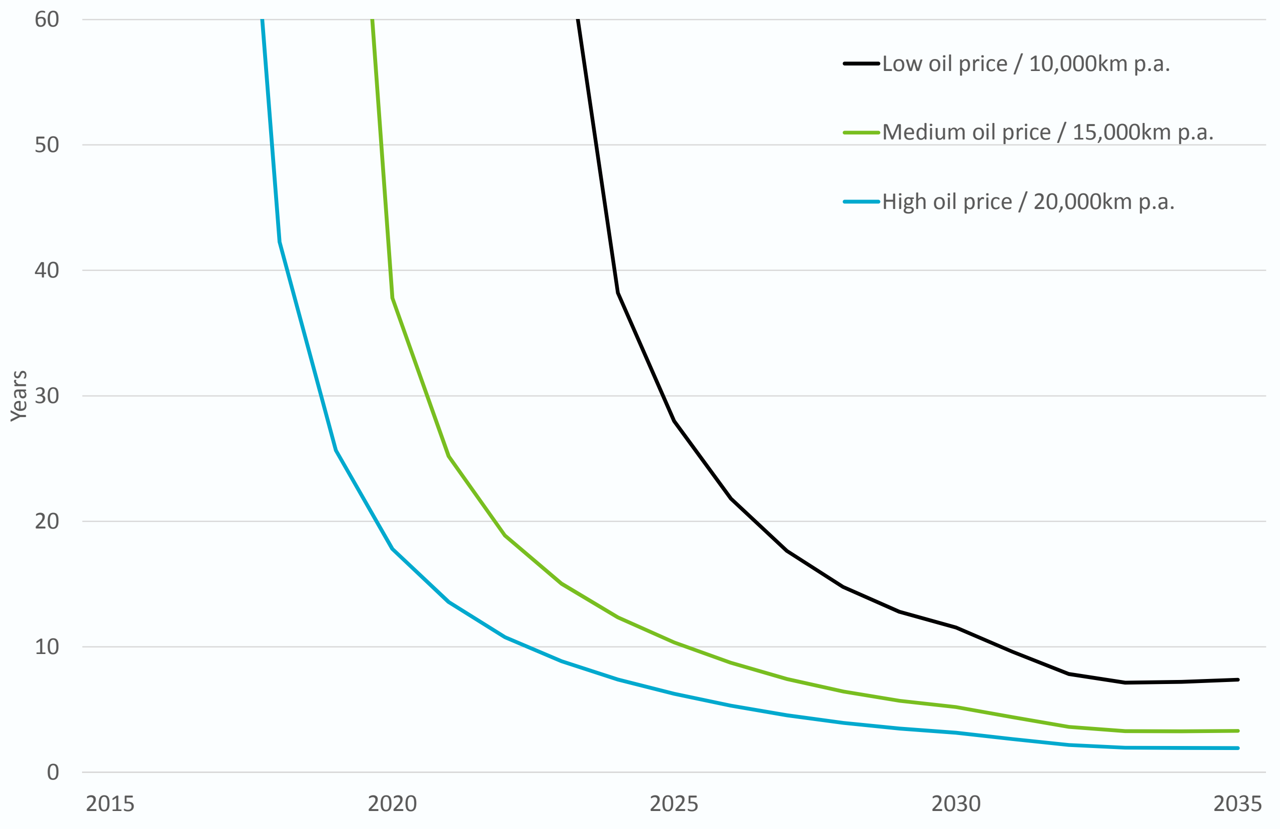

Figure 49: Discounted payback period to 2035 for heavy vehicle class PHEV

PHEV, plug-in hybrid electric vehicle

5.5.4 Conclusions

The economic viability of purchasing an EV will depend on the customer:

- How far do they travel per day and per annum and therefore what battery size suits them?
- Must the vehicle have long-range capability?
- What size of vehicle are they purchasing?
- Can a charger be added to their place of garage without major additional re-wiring or renovation?
- What are their expectations about the future price of petrol?

The diversity of customer's circumstances (travel distance, fuel price, vehicle size preferences and so on) mean that the adoption of EVs is likely to be mixed. In ideal circumstances, customers will reach acceptable payback periods of 5 years by 2028 and 10 years by 2021. In the medium cases examined, these payback periods are reached only 3 to 5 years later. However, in the worst case (i.e. low fuel price and low distance travelled) acceptable payback periods may not be reached until around 2035, depending on the vehicle size and type. If EV costs fall as expected, the analysis generally suggests that, except in the worst cases, economic viability will not be a major barrier for electric vehicles by 2035.

A major risk to this analysis is that the reduction in costs of EVs depends mainly on global adoption being large enough to allow manufacturing to achieve efficient scale. As such, this is the classic chicken and egg problem. Another major risk is that certain factors other than price will be stronger determinants of adoption; however, this analysis has only addressed economic viability.

6 Potential uptake

This section focuses on the potential uptake of battery storage among residential and commercial end-users rather than the full set of customer cases examined in Section 5. The reason for the narrower focus is that adoption at the end user is the factor likely to have the greatest impact. If adoption occurs on the grid side, this is likely to deliver operational and capital efficiencies as the main impact. Also, the considerable uncertainty in changes in generation peaking capacity and the case-specific nature of adoption in the network means that it is difficult to derive meaningful adoption cases for those applications.

6.1 Residential and commercial customer adoption

Estimates of potential uptake of batteries for ES in the NEM were projected to 2035 based on estimated payback periods, as reported in previous sections. It was assumed that electricity consumers, both residential and commercial, take up batteries on the basis that they provide a positive return on investment. Also, that this return increases as both potential electricity bill savings (due to the use of battery storage) increase over the coming decades and the unit cost of batteries decreases.

For projecting uptake rates, we used a standard S-curve trajectory (the logistic function) that is typically observed in many new technologies. The basis for this curve is that uptake is initially slow, as the new technology is initially relatively unknown and poorly understood by consumers. The rate of uptake increases as the technology becomes more familiar, but this process is limited by the total size of the market. Finally, the proportion of customers adopting the new technology approaches a saturation limit, in a process that can take several years or even decades.

The logistic function model can represent the influence of both economic and noneconomic factors in the adoption of a new product. This is because it can be parametrised to:

- respond favourably to improved economic performance
- take into account social and technical limitations on total potential uptake
- reflect the extent to which a given population has a culture of innovation – a willingness to adopt a new product in the absence of previous examples provided by other members of the community
- reflect the extent to which potential customers might tend to follow the uptake decisions of others.

Given that the market penetration of batteries for ES is presently very limited, it is not possible to use past observed rates of uptake to calibrate a future projection. However, it is possible to base projected uptake rates on analogous technologies. In this study we used data on the past uptake of solar PV as a model for the rate of uptake of batteries. This is reasonable since both technologies are applicable to the same market (electricity consumers), are of a similar order of magnitude of upfront capital cost, and have benefits corresponding to a reduction of energy bill. Both are of a similar (low) degree of technical complexity and sophistication and are thus relatively easy for the customer to understand and use, and their operation has a relatively minor impact on customer convenience. One distinctive difference is that (rooftop) solar PV is a technology that is more obviously visible to potential customers that have not yet adopted it, whereas the installation of a battery system within a building is unlikely to have an impact that is visible from the street.

The logistic uptake function provides an estimate of the proportion of a given market segment that adopts a new product over time. In this report, it is parametrised via a dependence on payback period. Also, the market is segmented by NEM state, and divided into a residential sector and a commercial sector, with several tariff alternatives (as described in Section 5).

6.2 Projected residential adoption rates

In our analysis of the economic viability of residential stationary battery storage, it became clear that customers with solar PV adopting ES would opt for a TOU tariff to minimise their electricity bill. This is because the batteries provide the ability to shift net demand from peak to off-peak times, and to manage the energy provided by the solar PV. For customers without solar PV, storage is of no benefit to those on a flat tariff, and is of limited benefit to those on the capacity tariff investigated, because peak demand is already lower than the minimum chargeable demand of 1.5 kW for all but large customers. For customers on a TOU tariff, however, storage again provides a benefit in terms of cost, because peak pricing period consumption can be met by electricity stored at off-peak times. Given that these were the most economic cases, we have shown their projected adoption as the best cases (and it can be surmised that adoption rates are lower for all other tariff–battery combinations).

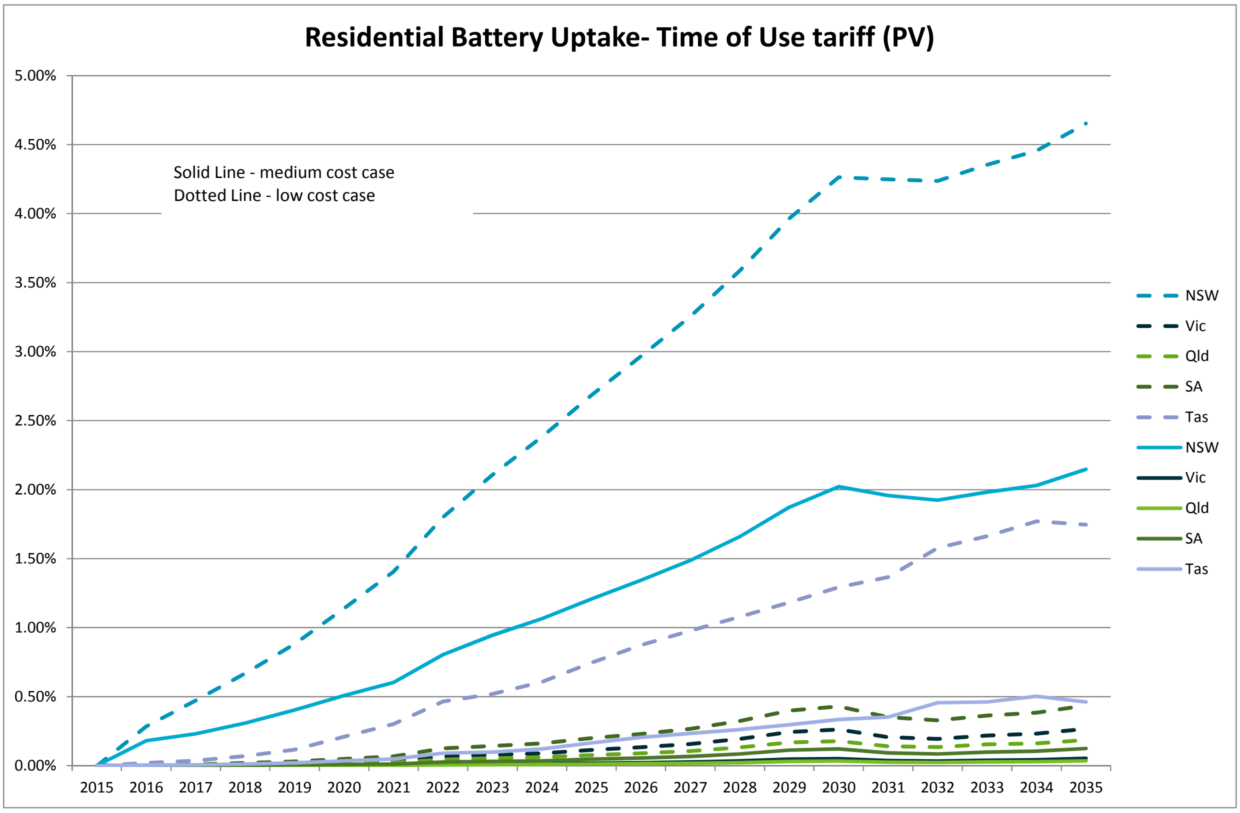

Figure 50: Projected adoption of residential battery storage for customers with solar PV under a time-of-use tariff

NSW, New South Wales; PV, photovoltaic; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

For residential customers with solar PV, the higher payback periods (> 10 years) for most of the projection period mean that adoption is in the low range of a few per cent, reaching a maximum of 4.7% in New South Wales by 2035 in the low-cost battery case (Figure 50). In the medium-cost battery case, the maximum adoption is 2.1% by 2035. There is a slight dip in the projected uptake near 2030 for most states because the benefit due to the solar feed-in tariff and small-scale technology certificates decreases significantly. This is later more than compensated for by the benefit due to reduced imports; that benefit is increasing with the retail cost of electricity.

For residential customers without solar PV, adding battery storage provided a much faster payback with a TOU tariff. Assuming the low-cost battery case, adoption reaches almost 18% by 2035 in New South Wales, and just over 12% in the next best cases (i.e. South Australia and Victoria). Under the medium-cost battery case, the maximum adoption is again in New South Wales, and reaches 8% by 2035. Across the states, adoption is the lowest in Queensland due to lower price differentials in the TOU tariff structure.

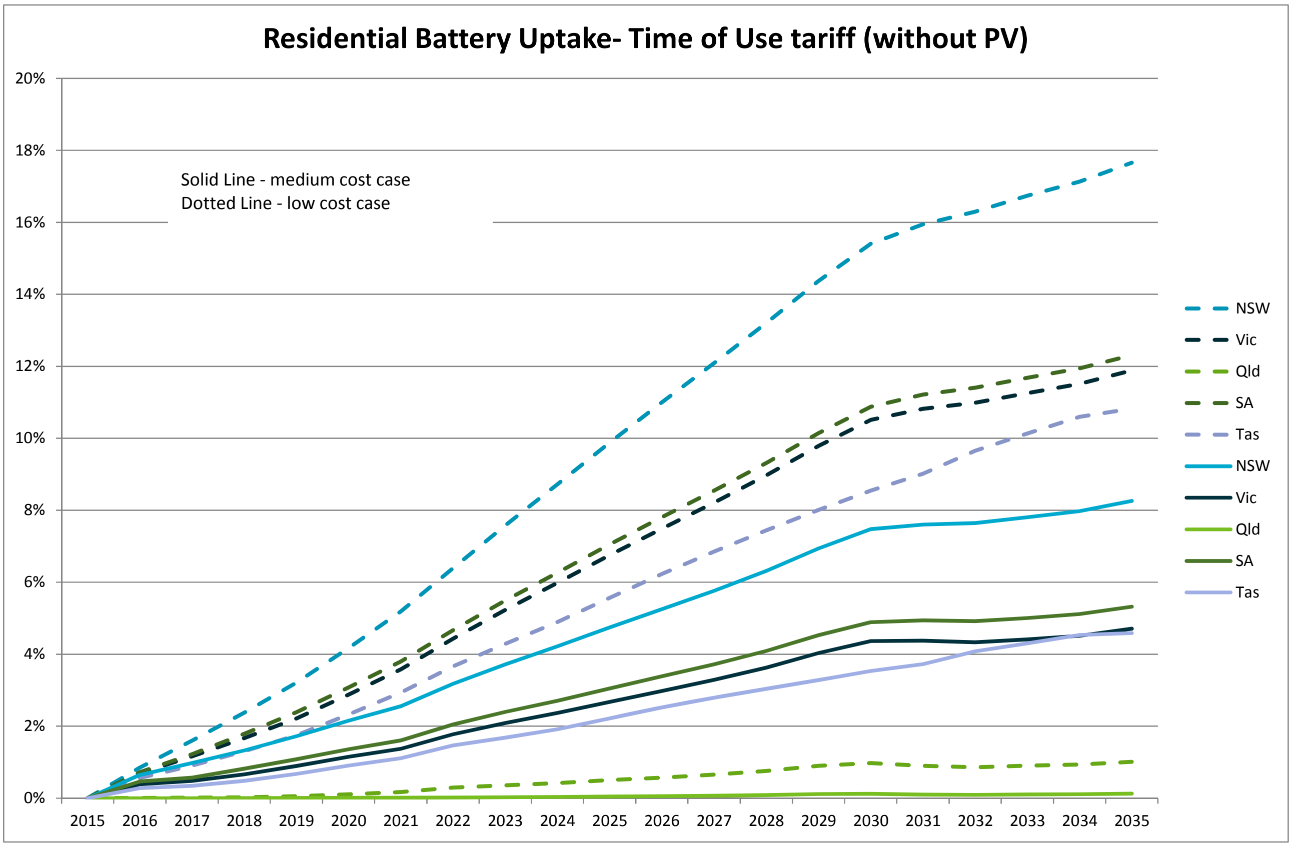

Figure 51: Projected adoption of residential battery storage for customers without solar PV under a TOU tariff

NSW, New South Wales; PV, photovoltaic; Qld, Queensland; SA, South Australia; Tas, Tasmania; TOU, time of use; Vic, Victoria

6.3 Projected commercial adoption rates

For commercial customers, the two tariffs that emerged as the most economically viable cases for battery adoption were the standard tariffs for customers without solar PV and a TOU tariff for customers with solar PV. We present these cases below as representing the highest adoption we would expect to see among commercial customers. For all other tariff combinations, the adoption of battery storage among commercial customers is lower.

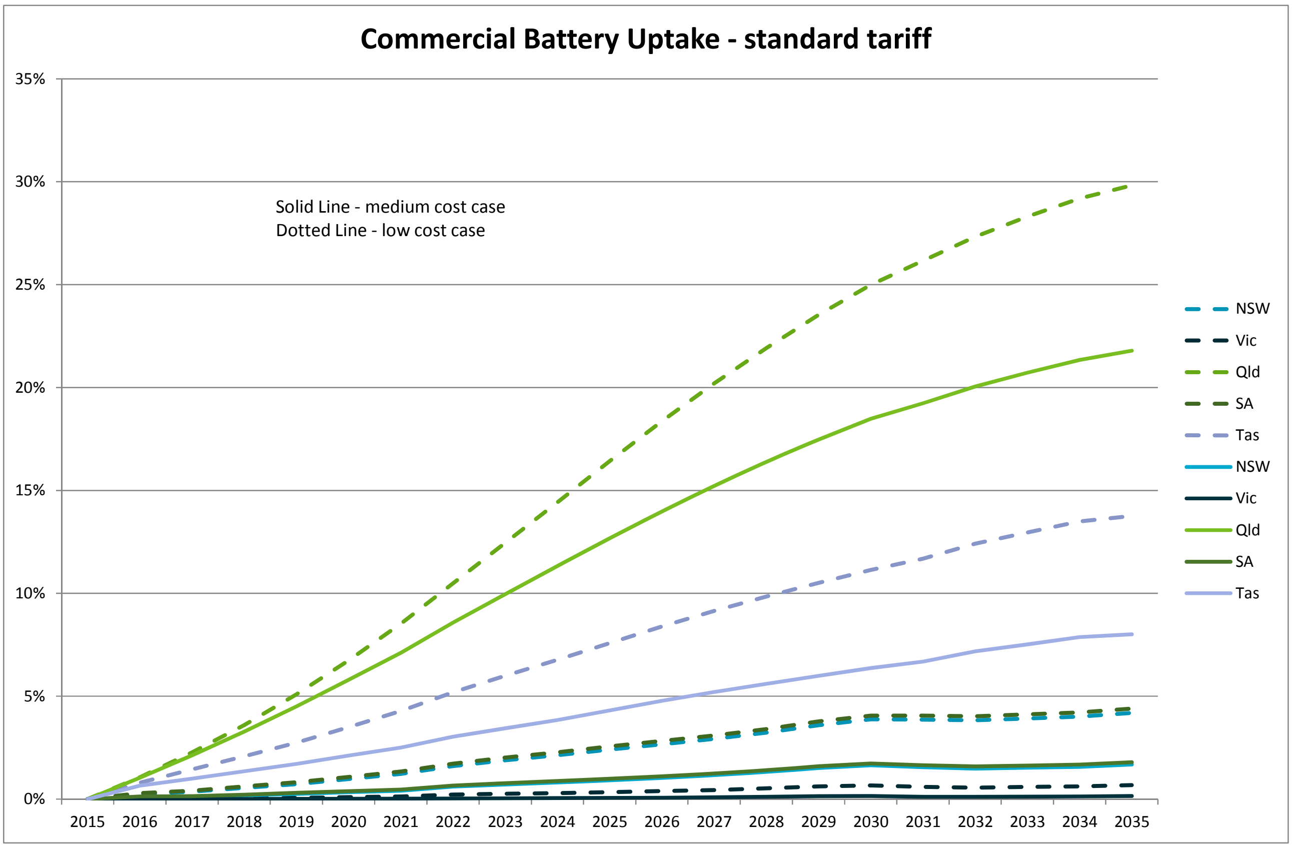

Figure 52: Projected adoption of commercial battery storage for customers without solar PV under a standard tariff

NSW, New South Wales; PV, photovoltaic; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Figure 52 shows that, under medium battery costs for customers without solar PV, we would expect to see as much as 22% adoption of battery storage in Queensland and 8% in Tasmania under existing tariffs, but substantially lower adoption (< 3%) in all other states. In the low-cost battery case, adoption increases to almost 30% and 14% in Queensland and Tasmania, respectively, and to less than 5% in all other states. It is the ability of batteries to decrease a customer's peak demand that encourages adoption. For the tariffs investigated in this study based on existing offerings, Queensland and Tasmania have significantly greater peak demand charge rates than those of the other states, accounting for the much higher adoption rates projected.

For customers with solar PV, Figure 53 shows that, under medium battery costs, adoption of battery storage will be highest in New South Wales (1.3%) by 2035 and lowest in Victoria (~0%). Under the low-cost battery case, the rate of adoption New South Wales improves to 4% by 2035 whereas that for Victoria shows almost no improvement. The diversity in adoption among solar PV owners reflects the variation in the differential prices between peak and off-peak times across states.

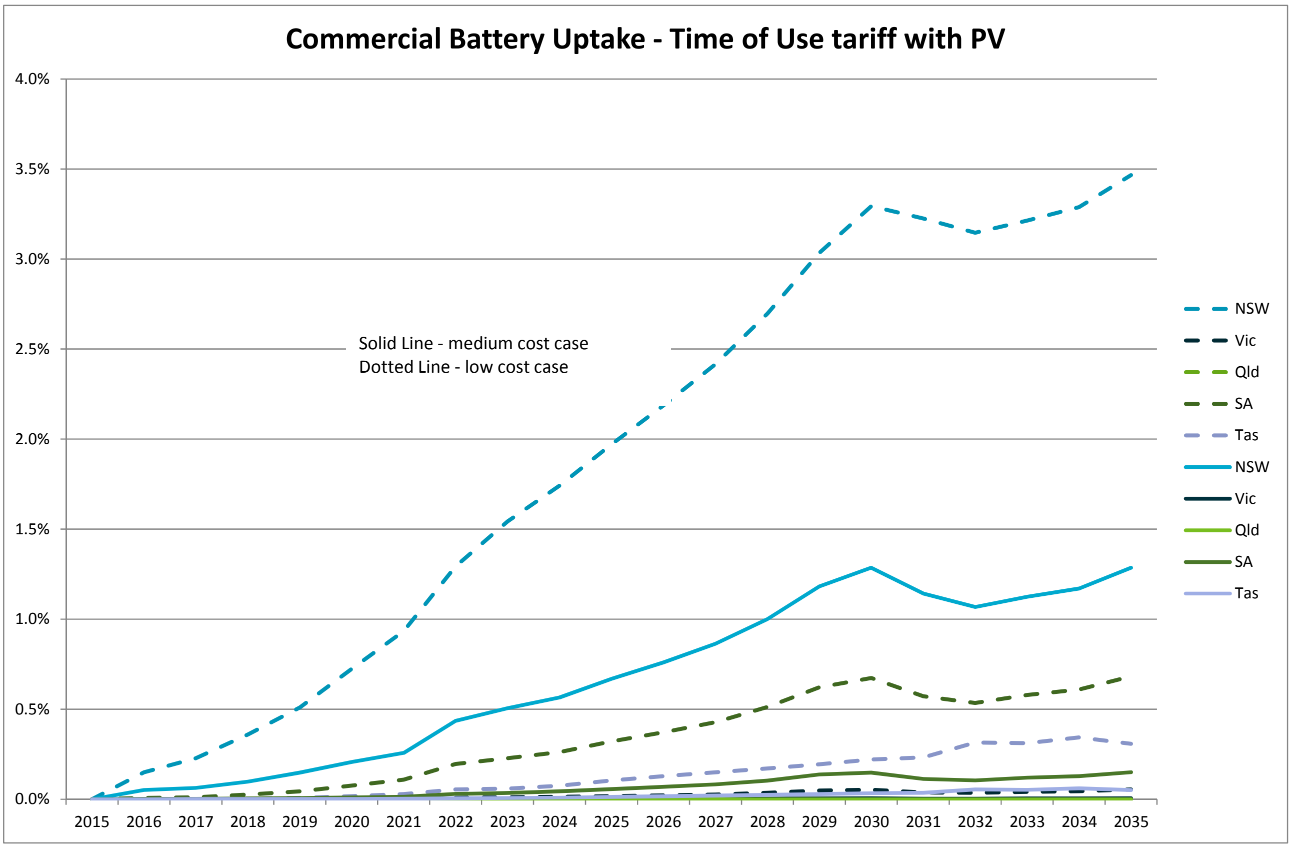

Figure 53: Projected adoption of commercial battery storage for customers with solar PV under a time-of-use tariff

NSW, New South Wales; PV, photovoltaic; Qld, Queensland; SA, South Australia; Tas, Tasmania; TOU, time of use; Vic, Victoria

6.4 Potential uptake of storage with solar PV

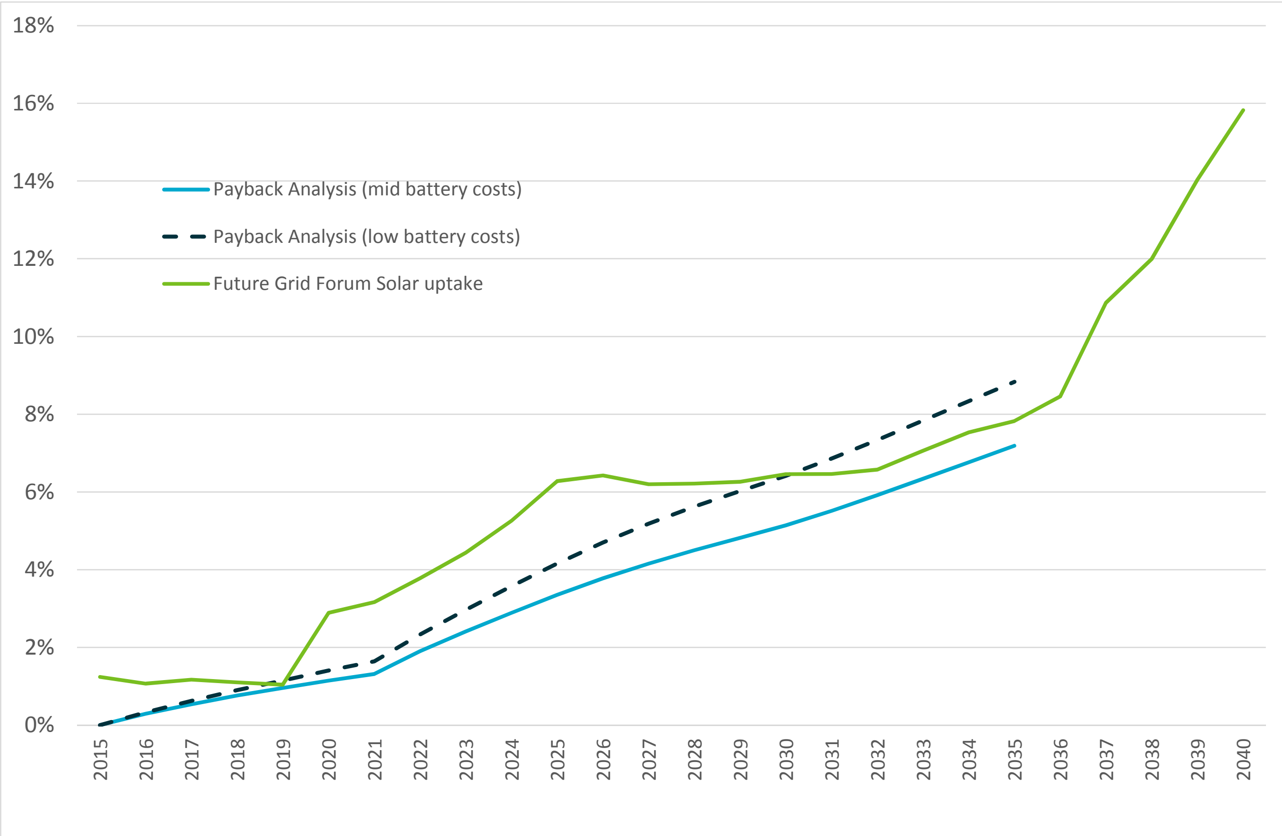

Figure 54: Projected adoption of combined PV and storage bundle

PV, photovoltaic

Payback period analysis also suggests that it will be economically viable for both residential and commercial customers to invest in a combined package of solar PV and batteries. Figure 54 shows projected total adoption percentages for combined solar PV and batteries among residential and commercial customers across all states in the NEM. For residential customers, a flat tariff was used, and for commercial customers the standard tariff with capacity charge was used. In both cases, it was assumed that no feed-in tariff is offered. The projections based on payback period are shown for comparison with adoption percentages from the *Future Grid Forum Scenario 2: Rise of the prosumer*. It can be seen that the projections based on payback period are in reasonable agreement.

6.5 Projected electric vehicle adoption rates

There are a number of electric vehicle adoption rates available in the literature and presented in Figure 55. All of the projections in the top half of the chart legend were made using CSIRO's ESM, but with different scenario assumptions, including with and without carbon prices, high and low carbon prices, different EV vehicle costs, different assumptions about the willingness to overcome range limitations, and different oil prices. The range across all of the scenarios to 2035 is almost negligible up to 69%. The Future Gird Forum scenarios are in the range of 17–34%.

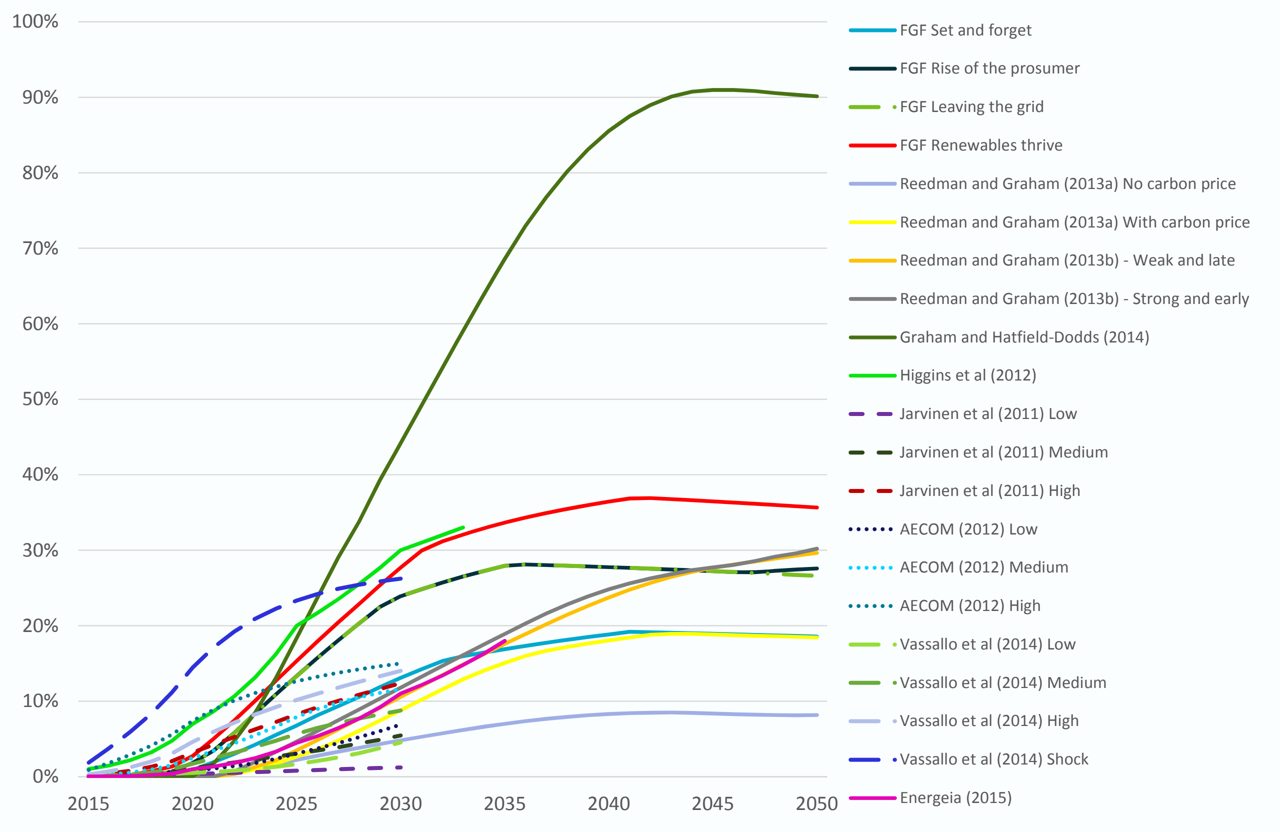

Figure 55: Electric vehicle adoption projections available in the literature

FGF, Future Gird Forum
Sources: [102, 103, 109–114]

Applying the same logistic curve method to the payback periods calculated for EVs in this report provides a projection that is consistent with the methodology applied for stationary battery applications. Given that our analysis of different vehicle size classes showed that payback periods were fairly similar by 2035, in the results that follow we focus on the medium-size vehicle class.

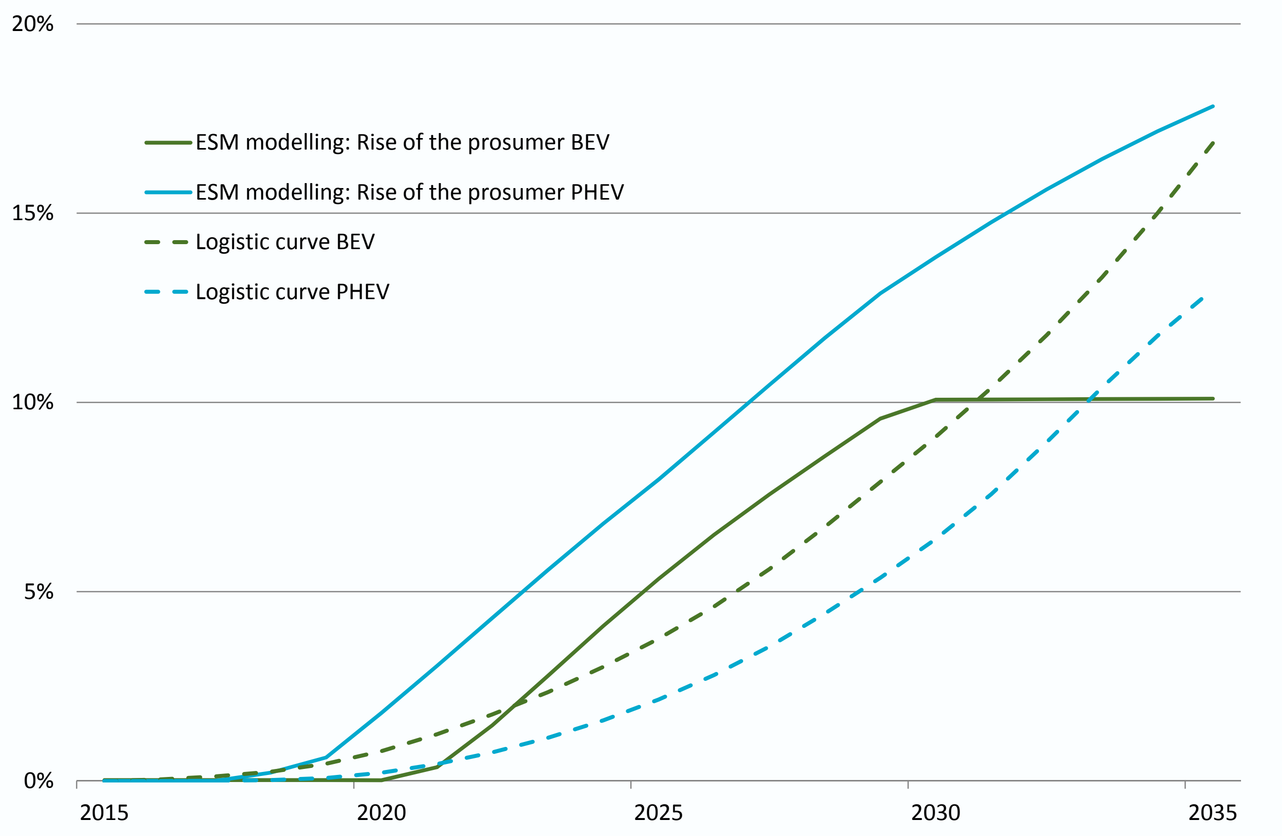

Figure 56: Projected adoption of EVs in the medium vehicle size class under CSIRO's ESM modelling of rise of the prosumer and the logistic curve approach by EV type

BEV, battery electric vehicle; CSIRO, Commonwealth Scientific and Industrial Research Organisation; ESM, Energy Sector Model; EV, electric vehicle; PHEV, plug-in hybrid electric vehicle

Given the different projection methodologies, Figure 56 shows surprising agreement between projections based on the ESM for *Future Grid Forum Scenario 2: Rise of the prosumer* and the logistic curve approach adopted in this study. ESM projects 10% adoption for BEVs and 17% for PHEVs, to reach a total of 27% for the medium-size vehicle class by 2035. The logistic curve approach projects 17% adoption for BEVs and just under 13% for PHEVs, to reach a total of 30% by 2035. Overall, the logistic curve approach projects higher uptake, particularly in relation to BEVs. However, this reflects the fact that ESM imposes a maximum share on short-range vehicles as a social constraint rather than a fundamentally different view about economic viability.

As discussed earlier in the report, there is little difference between payback periods across vehicle size class by 2035. Thus, these results for medium vehicle size are also indicative of BEV and PHEV adoption across the entire fleets of light vehicles, both passenger and light commercial.

7 Potential impacts

Several impacts from the adoption of storage could be explored, including tariff choice (which we discussed to some extent when examining economic viability) and demand behaviour (which we have not modified by assumption). However, this section focuses primarily on the impact on peak demand, because this drives a large proportion of costs in the electricity system, particularly distribution and transmission network and generation capacity. Initially, however, the potential qualitative impact of storage on the diurnal load profile is discussed.

7.1 Impact of storage on diurnal load profile

7.1.1 Impact of storage, variation by battery management strategy

A customer's tariff and whether or not solar PV is installed play a significant role in determining the incentives governing battery operations and the subsequent impact on the diurnal load profile. Figure 57 shows a typical daily load profile for a customer without PV installed, comparing the situation without storage (black dotted line) to cases with storage on a TOU tariff (blue) and storage on a capacity tariff (green). With the capacity tariff, the storage is used to smooth consumption over the entire day; hence, the resulting load profile is flatter, with both a low peak near 7 pm and a high trough near 5 am. With the TOU tariff, however, there is strong incentive to shift consumption from the daytime peak periods to the night-time off-peak. For the example shown, this succeeds in reducing load at the previous peak time of about 7 pm, but shifting consumption into the off-peak period, resulting in a 'rebound' peak after 10 pm that exceeds the previous one.

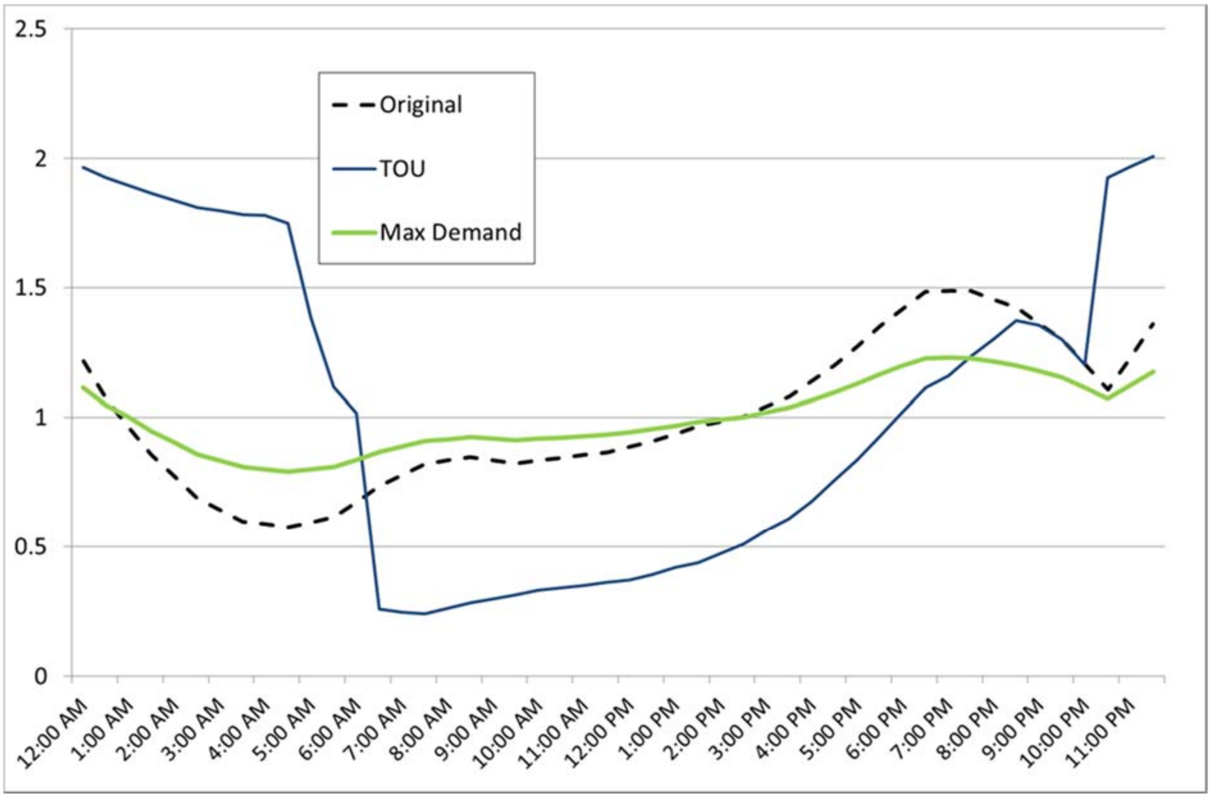

Figure 57: Diurnal load profile modifications – no solar PV

PV, photovoltaic; TOU, time of use

For the case of a customer with solar PV (Figure 58), storage can also have diverse effects on the resulting load profile, again depending on tariff type. The addition of PV generation (without storage) results in a negative net load during the middle of the day (dotted blue line). Where the feed-in tariff paid for power exported to the grid is less than the cost of imports on an otherwise flat tariff, the customer with storage has the incentive to store excess generation during the middle of the day when the price received for it would be low, and to use it later when the price of importing power would be higher. This results in a flatter profile (solid blue line). However, if the customer is also paying varying prices across the day with a TOU tariff, in addition to attempting to store excess generation produced by on-site solar, the storage capacity is again used to shift demand from peak to off-peak periods. This results in a demand profile (orange line) that is significantly lower during the middle of the day than in off-peak periods at night, inverting the profile typical of some of the larger customers seen in Figure 27.

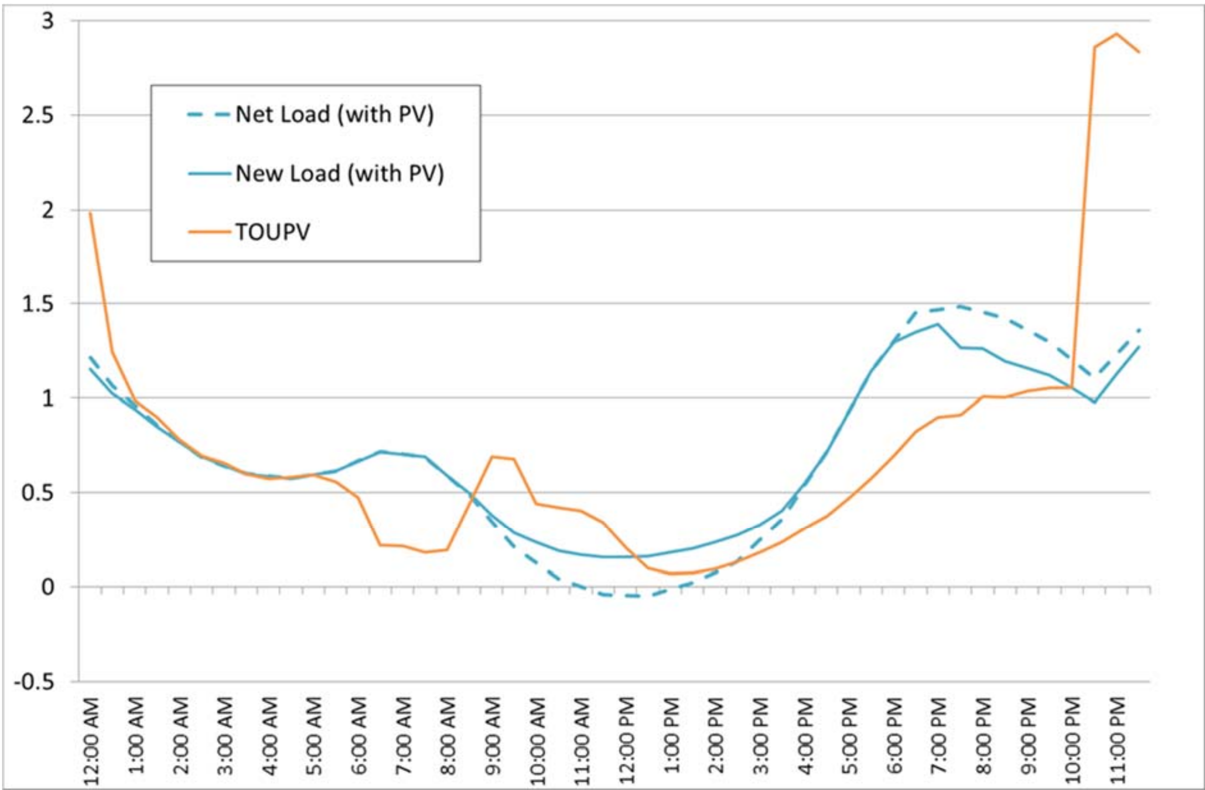

Figure 58: Diurnal load profile modifications – solar PV

PV, photovoltaic; TOU, time of use

The impact of storage on a typical day (as discussed above) can be qualitatively different from that on a high-demand day (see Figure 59). Without solar, on a capacity tariff, storage is used to minimise peak demand for the day. On a TOU tariff, storage that is sized for a typical day may quickly reach full capacity and not necessarily have an impact on the maximum demand for the day, depending on the sophistication of the storage operational management strategy and the particularities of the tariff. With solar, a storage system that is used to minimise net exports to the grid may have little impact on the diurnal profile, since on a high-demand day the customer's load may exceed generation at all times. With solar generation on a TOU tariff, as for the case without solar generation, the addition of storage may have limited impact on the daily peak if the stored energy reaches its maximum capacity well before the maximum daily net customer load is reached.

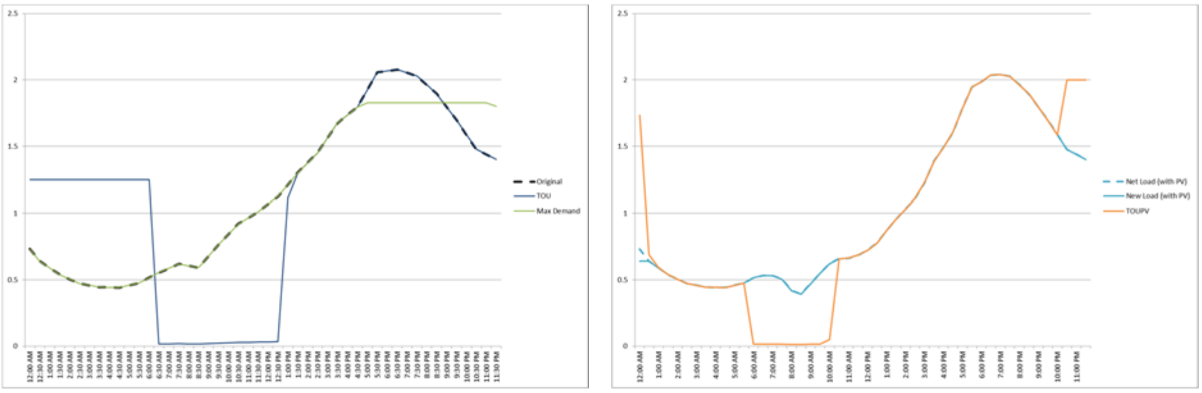

Figure 59: Diurnal load profile modifications – maximum demand day

7.1.2 Aggregate impact of storage, variation by market penetration of batteries

The aggregate demand profile depends on the behaviour of all customers, and thus the proportion of customers facing their individual incentives regarding their particular tariff and whether or not storage or on-site generation is installed. Where a small proportion of customers with storage presents profiles such as those shown in Figure 57 and Figure 58 , the net impact could be to flatten out the overall demand curve. However, at high penetrations of storage with TOU incentives at their current settings, the impact of the secondary rebound peaks on the aggregate demand would result in a higher maximum demand than is currently presented, unmodified by storage.

Figure 60 shows the typical impact of an increasing proportion of customers on a particular modified profile. The black line shows the unmodified aggregate profile of a group of customers. If they all took up storage and modified their behaviour in response to the same tariff – in this case, a TOU tariff – demand would typically be shifted from peak pricing periods in the middle of the day to off-peak periods, giving a U-shaped net result as discussed above. However, if only a proportion of them were to modify their behaviour, the resulting aggregate profile would be a weighted average of the modified and unmodified behaviour, as shown in Figure 60. The daily profile for the 10% of customers with storage following a specific modified pattern of demand results in a lower daily peak, as does the profile for the 20% of customers with storage. However, in this example, at 30% of customers with the modified profile, the secondary rebound peak in the evening begins to exceed the reduced peak of the midday period.

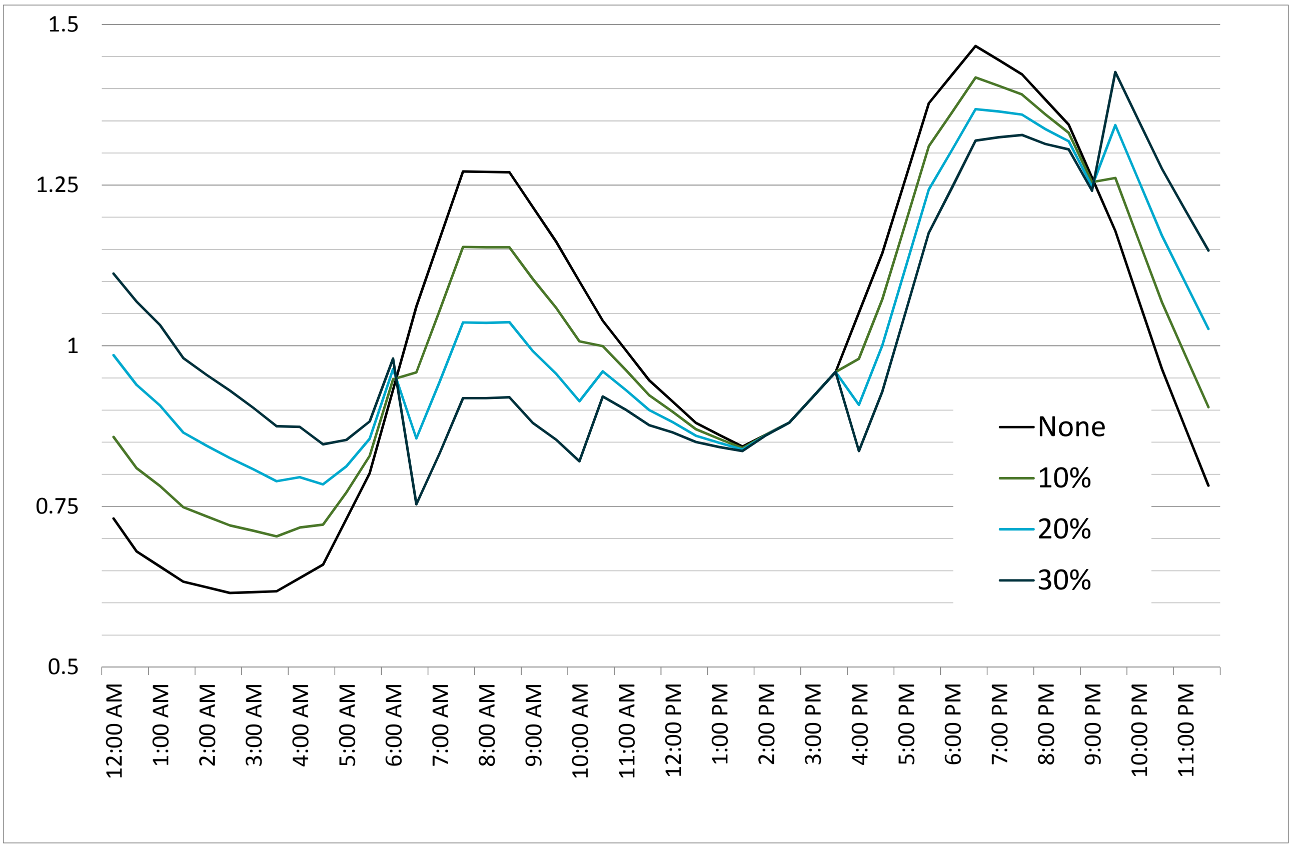

Figure 60: Aggregate load profile modifications – varying penetration proportions

It is likely that both tariffs offered by networks and pricing relativities would change before some of the more extreme modified load profiles became so common as to have a significantly adverse effect on the aggregate demand profile. As such and given existing data limitations, it is not particularly useful to attempt to project in detail the aggregate impact on the load profile of a significant uptake of storage over a diversity of customers, with a diversity of unmodified profiles, with a diversity of propensities for the uptake of storage and a diversity of potential tariff choices. The following section, however, provides some indication of the potential total capacity of storage uptake across the NEM.

7.1.3 Aggregate impact of storage on diurnal profiles

It is difficult to project the likely evolution of tariff structures and the corresponding proportion of customers on each tariff. Nevertheless, we can investigate the impact of alternative customer mixes on the aggregate daily profile. The following provides three snapshots of alternative possibilities of customer mix for the case of New South Wales, in order to provide an indication of the potential impact. Other states show qualitatively similar impacts. The assumptions regarding customer mix appear in Table 23 below, and include a high uptake of the capacity tariff (with storage and a low PV uptake), a high uptake of PV (and capacity tariff with storage), and a high uptake of the TOU tariff (with storage and a low PV uptake). These assumptions were selected to provide an indication of the sensitivity of the load profile to customer market share. They explore mixes of tariff choices and PV installation consistent with the higher ends of potential uptake ranges for batteries and solar that were presented in the previous section. The average diurnal profile is calculated as a weighted sum of customer market shares, as is the diurnal profile for the peak annual demand day. The resultant profiles, normalised to the average demand, are shown below.

Table 23: Customer mix assumptions for indicative aggregate impact of storage

	Capacity tariff high, PV low uptake		PV high uptake		TOU tariff high uptake	
	Residential	Nonresidential	Residential	Nonresidential	Residential	Nonresidential
Non-PV market share, of which tariff share	**80%**	**90%**	**40%**	**60%**	**80%**	**90%**
Flat tariff (no storage)	55	15	55	15	60	10
Peak tariff	40	80	40	80	10	80
TOU tariff	5	5	5	5	30	10
PV market share, of which tariff share	**20%**	**10%**	**60%**	**40%**	**20%**	**10%**
Flat PV	80	90	80	90	50	80
TOU PV	20	10	20	10	50	20

PV, photovoltaic; TOU, time of use

Figure 61 shows the diurnal profile for the first case, a relatively low market penetration of solar PV, with a reasonable uptake of storage in the residential sector and a move primarily to the capacity tariff. Here, solar PV has reduced net demand in the middle of the day, and battery operations for the capacity tariff have reduced the peak demand later in the day, despite some rebound peak at the beginning of the off-peak period.

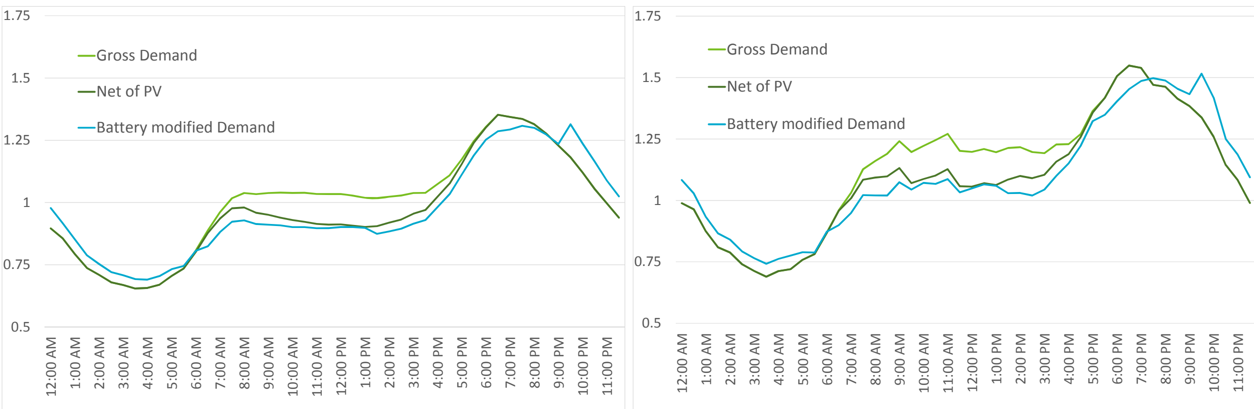

Figure 61: Indicative aggregate load profile (New South Wales) – high peak tariff, low PV case (left: average, right: peak demand day)

PV, photovoltaic

Figure 62 shows the impacts of a higher market penetration of solar PV. Here the incentive is to store energy during the day when there is solar power available, permitting a reduction in the existing evening peak. However, even the relatively small proportion of PV owners on a TOU tariff is enough to introduce a rebound peak that is of a similar magnitude to the unmodified demand profile.

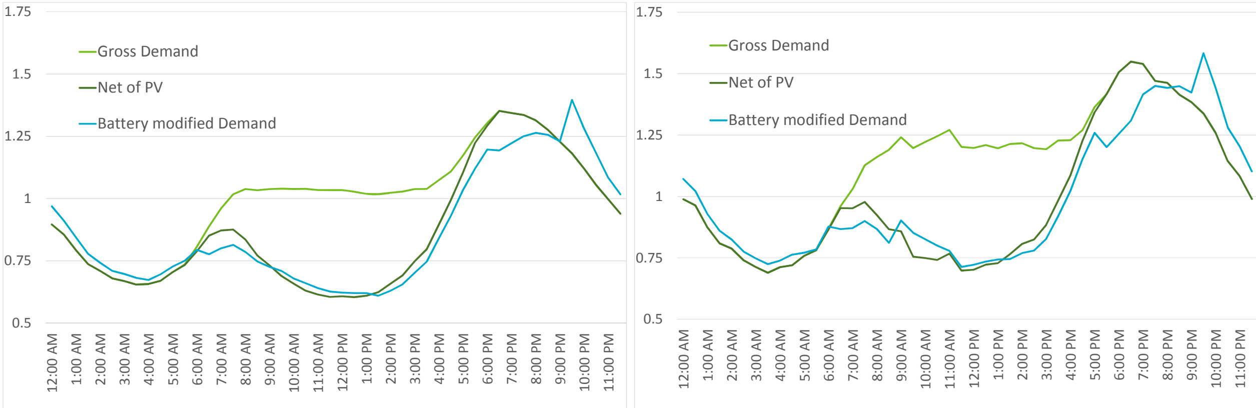

Figure 62: Indicative aggregate load profile (New South Wales) – high PV uptake case (left: average, right: peak demand day)

PV, photovoltaic

Figure 63 suggests that, with incentives provided by existing tariffs, but with a larger proportion of customers on a TOU tariff, a potential outcome is a rebound peak that exceeds the magnitude of the unmodified demand profile. However, provided the electricity market is sufficiently flexible to allow appropriate adjustments to be made, these incentives would probably be reshaped to discourage the uptake of storage from resulting in a significant rebound peak. For example, the start of the off-peak period might be postponed to the late evening or early morning, or the price differential between peak and off-peak periods might be reduced. Similar remarks apply to the second case of high PV uptake shown in Figure 62.

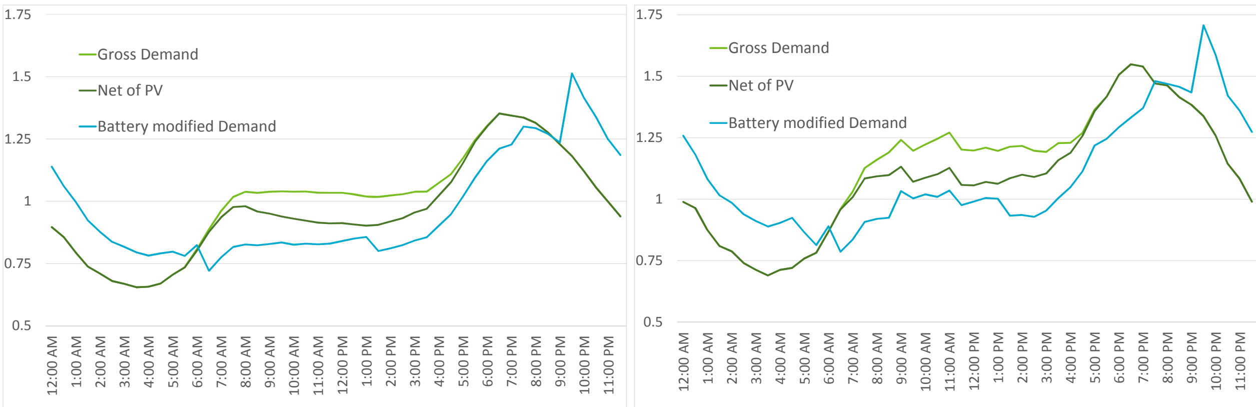

Figure 63: Indicative aggregate load profile (New South Wales) – high TOU tariff uptake case (left: average, right: peak demand day)

PV, photovoltaic; TOU, time of use

These indicative profiles show that – under the incentives provided by tariffs based on what is available in today's market, and the market shares assumed above with assumptions that encourage the uptake of batteries – there could be a rebound peak in demand introduced at the start of the existing off-peak period. This effect is greater as more customers move to a TOU tariff. At a sufficiently high uptake of the TOU tariff with storage under existing tariffs, shifting demand to the off-peak period could overcompensate for the reduction in the existing peak. This is based on the assumption of a constant price for electricity consumers during the currently defined off-peak period, so that there is no incentive to shift battery charging demand away from the start of that period to later in the off-peak period, when non-storage energy consumption is even lower.

To reduce the maximum capacity required by the network, it appears attractive for most consumers to be faced with the load smoothing incentives of a capacity tariff. However, a smoothed aggregate load profile could be also achieved if only a relatively small proportion of customers reduced their net load significantly during peak times by drawing on stored energy, provided that recharging took place over a sufficiently long time period to avoid a rebound peak of greater magnitude than the original. There may be economies of scale associated with this latter alternative.

7.2 Potential quantitative impact on peak demand

To project the total impact of residential and commercial customer adoption across the entire market, we aggregated the uptake results from each market segment in proportion to the size of the market segment. For that purpose we needed to multiply through, by state, the:

- share of stationary battery adoption for each customer segment and group (presented in the previous section)
- scale of consumption of each customer segment (Table 24)
- share of each customer segment within a customer group (Table 25)
- share of each customer group with total electricity demand (Table 26)
- power rating of the battery for each customer (Table 27).

The calculated impact in MW and percentage reduction by region are shown in Table 28 and Table 29. It assumes the uptake of batteries with solar PV in a bundle corresponding to the assumptions in the previous section, for the case of no feed-in tariff. For the remaining customers who do not adopt solar PV, the uptake of batteries is based on the selection of the TOU tariff in both the residential and commercial sectors, for consistency, to reflect the likely evolution over time away from flat tariffs. The range shown represents the difference between the impacts under the different battery cost cases explored. These results are indicative only. For example, we did not attempt to estimate the proportion of customers for which the TOU tariff would be the most attractive, nor the proportion of customers that might represent a maximum market saturation of less than 100% due, for example, to lack of suitable location for PV or battery installation, or the impacts of split incentives where a building tenant is not the owner.

These calculations represent the implied reductions in peak demand that could be achieved based on all customers deploying the full capacity of their batteries and using the capacity of the battery at peak demand. These approximations are likely to be reasonably accurate in the short term as the TOU tariff structure does reflect peak demand times at present. However, in the longer term it is possible that the actual peak will shift compared to the peak as defined by current tariff structures. This could occur in response to deployment of solar panels in particular, possible new air-conditioning technologies and control systems, and deployment of storage itself.

Table 24: Scale of consumption of representative customer profile

Sector	State	Small kWh/day MWh/year	Medium	Large
Residential	NSW	5.1 1.87	13.4 4.89	31.4 11.44
	Vic	4.7 1.72	10.5 3.82	22.5 8.21
	Qld	4.7 1.70	12.2 4.45	28.5 10.41
	SA	6.2 2.28	13.4 4.91	26.6 9.72
	Tas	5.2 1.90	12.3 4.50	27.4 10.00
Commercial		24.0 8.76	72.0 26.3	360.0 131.4

NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Table 25: Proportion of energy served by various customer scales

		Small	Medium	Large
Residential	MWh/year kWh/day	< 4.0 < 10.95	4.0–8.0 10.95–21.90	> 8.0 > 21.90
	% by number	45.8%	37.2%	17.0%
	% by energy	22.0%	40.7%	37.4%
Commercial	% by energy	33.3%	33.3%	33.3%

Table 26: Residential/commercial proportion

State	2015	2020	2025	2035
NSW	28.4% / 71.6%	28.7% / 71.3%	30.8% / 69.2%	33.3% / 66.7%
Vic	25.0% / 75.0%	25.5% / 74.5%	27.2% / 72.8%	29.3% / 70.7%
Qld	19.8% / 80.2%	20.0% / 80.0%	77.8% / 27.2%	24.5% / 75.4%
SA	35.8% / 64.2%	36.4% / 63.6%	37.6% / 62.4%	38.8% / 61.2%
Tas	20.5% / 79.5%	20.7% / 79.3%	24.7% / 75.3%	29.6% / 70.4%

NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Table 27: Typical battery system scale for various tariff types and customer scale

Sector	Tariff	Small kWh (kW)	Medium	Large
Residential	Peak demand	0.6–1.6 (0.16–0.50)	1.5–2.5 (0.2–0.6)	2–6 (0.4–1.1)
	TOU	2.5–3.0 (0.4–0.7)	5.0–7.0 (0.8–1.0)	7.0–15.0 (1.0–2.9)
	PV with low feed-in tariff	0.5–1.5 (0.20–0.52)	1.4–2.5 (0.3–0.5)	2.0–5.0 (0.5–1.0)
	PV with TOU	1.7–7.0 (0.4–3.5)	4.0–6.0 (1.0–3.0)	5.0–10.0 (2.0–3.0)
Commercial	Peak demand	10 (1.0)	30 (3.0)	150 (15.0)
	TOU	10.0 1.33	30.0 4.0	150.0 20.0
	PV with low feed-in tariff	3.33 0.67	10.0 2.0	50.0 10.0
	PV with TOU	7.3 2.5	22 7.5	110 37.5

PV, photovoltaic; TOU, time of use

Table 28: The potential reduction in peak demand implied by residential and commercial battery capacity, excluding EVs (MW)

	NSW	SA	Vic	Qld	Tas
2018	146–224	31–47	41–74	32–40	6–11
2020	228–378	52–83	66–125	49–65	9–19
2025	550–940	119–198	175–322	144–203	28–54
2030	883–1500	185–306	290–524	237–339	46–87
2035	1085–1822	227–372	367–648	345–475	61–111

EV, electric vehicle; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

Table 29: The potential reduction in peak demand implied by residential and commercial battery capacity, excluding EVs (% of forecast maximum demand)

	NSW	SA	Vic	Qld	Tas
2018	1.1–1.7	1.1–1.6	0.5–0.8	0.3–0.4	0.3–0.6
2020	1.7–2.8	1.8–2.8	0.7–1.4	0.5–0.7	0.5–1.1
2025	3.9–6.6	4.1–6.7	2–3.6	1.5–2.1	1.6–3.1
2030	6–10.1	6.4–10.6	3.3–6	2.4–3.4	2.7–5.1
2035	7.2–12.2	7.9–13	4.3–7.6	3.6–4.9	3.9–7.2

EV, electric vehicle; NSW, New South Wales; Qld, Queensland; SA, South Australia; Tas, Tasmania; Vic, Victoria

8 Summary of main findings

The costs of ES technologies are projected to decline significantly in the future. This will be driven by technological learning, economies of scale in manufacturing, and additions to global cumulative capacity in transport and power applications. Although the future cost of ES technologies at a particular point in time is subject to considerable uncertainty, costs are estimated to decline rapidly, particularly over the next decade: in the range of 53–85%, depending on battery chemistry. The projected battery costs in this study fall within the range estimated by other sources.

For utility-side applications, the economic viability of storage in distribution or transmission networks is plausible but case specific. Discharging battery storage to reduce peaks in electricity demand across the grid may defer capital expenditure and improve use of networks. The co-location of storage with intermittent renewable generation such as solar PV could also defer upgrades in existing voltage control or protection schemes, and improve the quality of the power supplied to customers. In cases where residential-scale battery storage is charged and discharged in order to smooth load cycle peaks and valleys, steady-state ratings applied in the distribution grid may need to be reduced from a cyclic to a continuous rating. Based on a case study we explored, battery storage was found to be a viable demand management strategy for operators of transmission or subtransmission networks under certain assumptions.

New connections of large loads or moderate-size generators can face substantial costs that depend on the voltage level at which they connect to the network. The example case explored in this study showed that co-location of ES may reduce the voltage level at which the load or generator connects. Although the economics are highly variable, a database of connection costs by location would permit a more thorough investigation of the cost point that batteries must achieve to make this an attractive option. This is an avenue for further research.

For customer-side applications, the economic viability of storage is sensitive to region, tariff structure and whether solar PV is already installed. There are also differing views on what may constitute a reasonable payback period for a commercial or residential customer.

The installation of an integrated storage system with solar PV to commercial premises was found to be the most attractive application. For baseline battery costs and large-size commercial customers in all NEM states, the payback periods on a standard tariff decline over the projection period, from 7–9 years in 2015 to 4–5 years by 2035. For a TOU tariff, they decline over the projection period from 17–29 years in 2015 to 7–11 years by 2035.

For commercial entities without solar PV, the retrofit of battery storage is more attractive in Queensland and Tasmania under standard tariff structures, and in New South Wales and South Australia under TOU tariff structures. However, the retrofit of battery storage is attractive in Queensland and to a lesser extent Tasmania for sites with solar PV under standard tariff structures.

In contrast, ES could be viable for households in 7 years under current tariff structures. Similar to the case with commercial sites, newly installed integrated storage and solar PV systems were found to be the most viable application.

For baseline battery costs and large-size residential customers in most NEM states, the payback periods for newly installed storage and solar PV systems on a TOU tariff decline over the projection period, from 11–35 years in 2015 to 6–12 years by 2035. For flat tariff structures, payback periods decline over the projection period, from 9–12 years in 2015 to 4–6 years by 2035.

In other application cases, for households without solar PV, battery storage under TOU tariff pricing provides the most value to households, particularly in New South Wales. For baseline battery costs and large-size customers in most NEM states, the payback periods for battery storage for households without PV on a TOU tariff decline over the projection period, from 17–35 years in 2015 to 8–11 years by 2035. For households with solar PV already installed, battery storage does not provide significant additional benefits under flat tariff or TOU pricing. Battery storage under capacity pricing was found to be unviable for households, based on the tariff structure that was assumed.

There is currently excess generation capacity in the NEM. If a gap in peaking capacity were to emerge, batteries are likely to be cost competitive with gas peaking plant to provide load-following services in the NEM between 2025 and 2035. The competitiveness of batteries in load-following services was found to improve as the share of intermittent renewable electricity generation increases. The confidence of the results of this economic analysis could be improved with a more temporally disaggregated, time-sequential review of battery and peaking plant application in a model of the wholesale electricity market.

The uptake of EVs is likely to be low in the next decade or so, but to increase to a potential 30% by 2035 under medium assumptions. The uptake of EVs is sensitive to future vehicle costs, projected oil prices and patterns of vehicle usage (km/year). The purchase of EVs is more attractive if much higher oil prices were to eventuate, improving the payback period through avoided fuel costs.

This study estimated significant adoption of stationary and vehicle battery storage by 2035. The adoption over time varies by region and is impacted by the tariff structure and whether on-site solar PV is present. The residential sector appears to be the most attractive market segment for the adoption of customer-side battery storage.

Battery storage reduces peak demand at times where the current tariff structure encourages customers to do so, in particular, during the highest TOU cost period for customers subject to that tariff.

This study found that, if customer-side battery storage is discharged at system peak, 2.1–3.4 GW of reduction in NEM maximum demand is possible by 2035. The most significant opportunity in percentage terms is in New South Wales and South Australia.

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Part 3 Appendices

9 Methodologies

9.1 Global and Local Learning Model additional information

9.1.1 Main components

The main components of the Global and Local Learning Model (GALLM) are:

- two modes of regional coverage:
  - a three-region model, with Australia, rest of developed world and developing world
  - a nine-region model with the United States, western Europe, eastern Europe, China, India, Russia, Australia, rest of developed world and rest of less developed world
- 21 centralised generation electricity plant types: black coal pulverised fuel; black coal integrated gasification combined cycle (IGCC); black coal with CO_2 capture and sequestration (CCS) (90% capture rate); brown coal pulverised fuel; brown coal IGCC; brown coal with CCS (90% capture rate); natural gas combined cycle; natural gas peaking plant; natural gas with CCS (90% capture rate); oil-fired generation; biomass; biomass with CCS (90% capture rate); hydro; wind; solar thermal; large-scale solar photovoltaic (PV); conventional geothermal; hot fractured rocks (geothermal); wave, ocean current or tidal; and nuclear
- four distributed generation (DG) electricity plant types: gas combined heat and power (CHP); rooftop solar PV; rooftop solar PV with batteries; and fuel cells
- two battery chemistries: lithium-ion (Li-ion) and flow
- time, represented in annual frequency.

All technologies are assessed on the basis of their relative costs subject to constraints such as the turnover of capital stock, and existing or new policies such as subsidies and taxes. The model aims to mirror real-world investment decisions by simultaneously taking into account:

- the requirement to earn a reasonable return on investment over the life of a plant or vehicle
- that the actions of one investor or user affects the financial viability of all other investors or users simultaneously and dynamically
- that the consumption of energy resources by one user affects the price and availability of that resource for other users, and the overall cost of energy services
- energy market policies and regulations.

The model projects uptake on the basis of cost competitiveness but at the same time takes into account constraints on the operation of energy markets, greenhouse gas emission limits, existing plant stock in each region, and lead times in the availability of new plant. It does not take into account issues such as community acceptance of technologies, but these can be controlled by imposing various scenario assumptions that constrain the solution to user-provided limits.

9.1.2 GALLM model inputs

GALLM requires both economic and biophysical data in order to support the selection of a least cost solution that is within biophysical limits of the technologies and energy resources that are employed. Key economic data include:

- global and national carbon price or emission limit
- historical costs of electricity generation technology
- fuel prices to electricity generators.

Key biophysical data include:

- observed or calculated learning rates
- existing stock and age of generators by region
- regional resource or technology constraints
- electricity technology capacity factor and supply constraints
- regional electricity energy consumption and peak demand growth.

9.1.3 GALLM model outputs

For given time paths of the exogenous (or input) variables that define the economic environment, GALLM determines the time paths of the endogenous (output) variables. Key output variables include:

- the change in the capital cost of electricity generation and battery technologies
- uptake of electricity generation technology and battery technology
- fuel consumption
- greenhouse gas emissions
- wholesale electricity prices.

Some of these outputs can also be defined as fixed inputs depending upon the design of the scenario.

The endogenous variables are determined using demand and production relationships, commodity balance definitions and assumptions of competitive markets at each time step. With respect to asset markets, it is assumed that market participants know future outcomes of their joint actions over the entire time horizon of the model.

9.1.4 Example model outputs

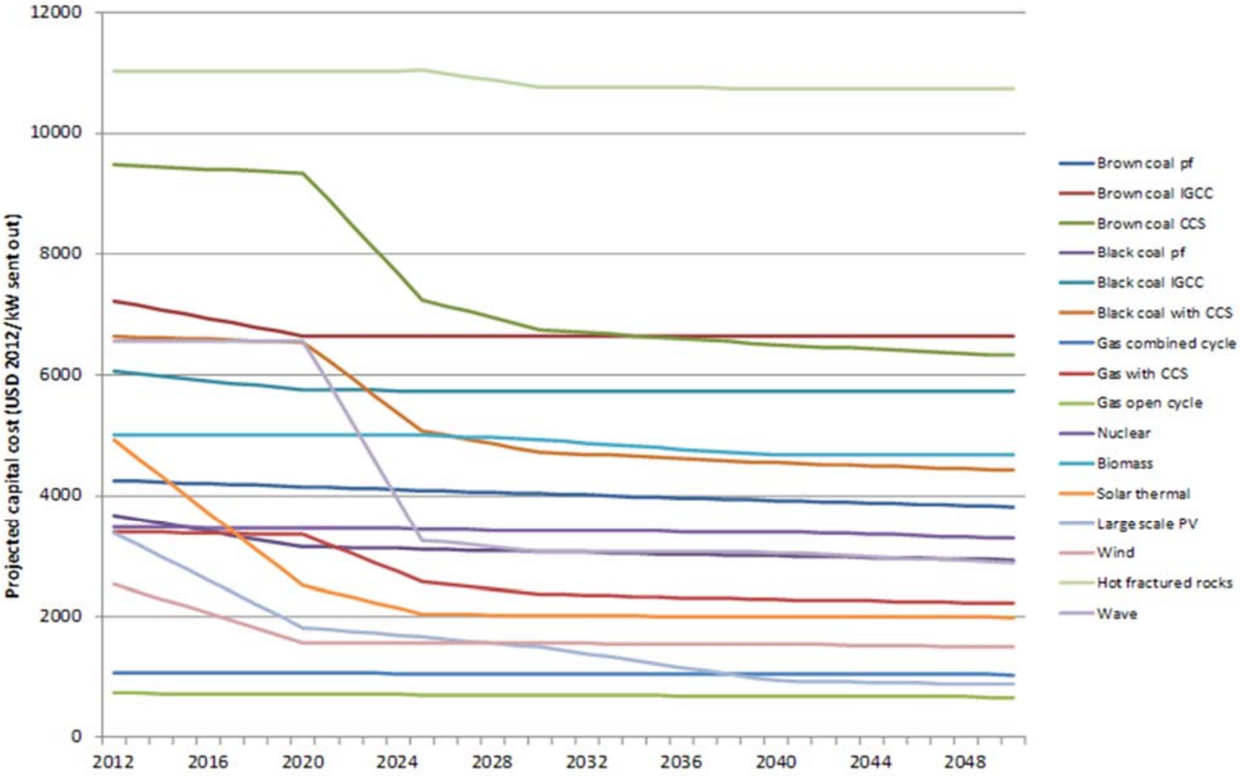

Figure 64: Projection of changes in electricity generation plant costs to 2050

CCS, carbon capture and storage; IGCC, integrated gasification combined cycle; pf, pulverised fuel; PV, photovoltaic

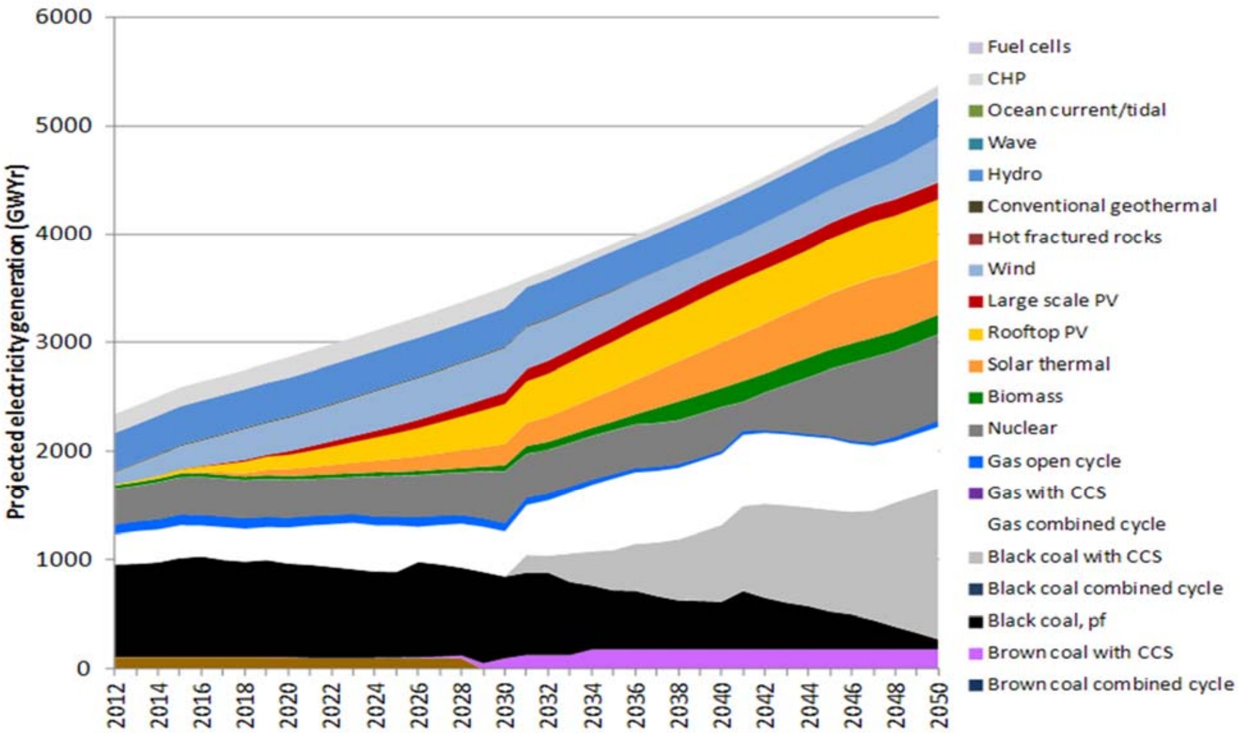

Figure 65: Projected global uptake of electricity generation technologies to 2050

CHP, combined heat and power; CCS, carbon capture and storage; IGCC, integrated gasification combined cycle; pf, pulverised fuel; PV, photovoltaic

10 Tariff references

Table 30: Tariff sources used in the analysis

	Retailer	Source document title	Date	Source document URL
Not used	Energy Australia	Energy price fact sheet NSW business (electricity)	Jan 2015	http://www.energyaustralia.com.au/small-business/electricity-and-gas/plans/nsw-plans
T2	Energy Australia	Energy price fact sheet NSW residential (electricity)	Jan 2015	http://www.energyaustralia.com.au/small-business/electricity-and-gas/plans/nsw-plans
T3	Origin	NSW small business energy price fact sheet Electricity Ausgrid distribution zone	July 2015	http://www.originenergy.com.au/content/dam/origin/business/Documents/energy-price-fact-sheets/nsw/NSW_Electricity_Small%20Business_AusGrid_Standard%20Published%20Rate.PDF
T4	Australian Power and Gas	Pricing schedule – Electricity (Qld) Australian Power & Gas standing prices	July 2013	http://www.agl.com.au/~/media/AGL/Residential/Documents/Plans%20and%20Pricing/2014/APG%20QLD%20elec.pdf
T5	Origin	Qld small business energy price fact sheet Electricity Energex distribution zone	July 2015	http://www.originenergy.com.au/content/dam/origin/business/Documents/energy-price-fact-sheets/qld/QLD_Electricity_Small%20Business_Energex_Standard%20Published%20Rate.PDF
T6	Ergon Energy	Energy price fact sheet Small business tariffs	Jun 2016	https://www.ergon.com.au/__data/assets/pdf_file/0006/269961/Energy-Price-Factsheet-Business-1-July-2015-to-30-June-2016.pdf
T7	ERM Business Energy	Victoria – Small business – Market contract – Jemena Distribution Zone Electricity: Energy price fact sheet	Jan 2015	http://www.ermpower.com.au/wp-content/uploads/2013/09/VIC_ADJ_JE_BUS-20150115.pdf
T8	Victorian Government Printer	Victoria government gazette No. S 139 Wednesday 3 June 2015	June 2015	http://www.gazette.vic.gov.au/gazette/Gazettes2015/GG2015S139.pdf
T9	Victorian Government Printer	Victoria government gazette No. S 426 Monday 1 December 2014	Dec 2014	http://www.gazette.vic.gov.au/gazette/Gazettes2014/GG2014S426.pdf
T10	Energy Australia	Energy price fact sheet SA business (electricity)	July 2015	http://www.energyaustralia.com.au/small-business/electricity-and-gas/plans/sa-plans
T11	Energy Australia	Energy price fact sheet SA residential (electricity)	July 2015	http://www.energyaustralia.com.au/residential/electricity-and-gas/plans/sa-plans

	Retailer	Source document title	Date	Source document URL
T11a	SA Power Networks	SA Power Networks network tariffs – business LV Low voltage agreed demand	July 2015	http://www.sapowernetworks.com.au/public/download.jsp?id=50876
T11b		Personal communication		
T12	Aurora	Aurora's approved electricity tariffs from 1 July 2013	July 2013	http://auroraenergy.com.au/Aurora/media/pdf/residential-pricing-july-2013.pdf
T13	Aurora	Energy price fact sheet Aurora Energy business time of use – Southern Tasmania – AUR12551MS	June 2014	https://auroraenergy.com.au/Aurora/media/pdf/small_to_medium_business/Price-Fact-Sheet-_-Business-Time-of-Use-Southern-Tasmania.pdf
T14	Aurora	Electricity rates & charges For your business 1 July 2014 – 30 June 2015	July 2014	https://www-test2.auroraenergy.com.au/Aurora/media/pdf/Small_Business_Rates_Charges_2014.pdf (now replaced by http://www.auroraenergy.com.au/Aurora/media/pdf/Small_Business_Rates_Charges_2015.pdf)
T15	Solar Choice	State solar feed-in tariffs	2015	http://www.solarchoice.net.au/solar-rebates/solar-feed-in-rewards

11 Results tables

11.1 Payback periods for residential end-use cases

Table 31: Discounted payback periods for residential customers, mid-range battery costs, TOU end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	17.6	19.3	28.7	>100	>100	>100	29.4	25.5	40.3	35.8	43.7	93.2	33.0	39.9	47.0
2016	20.9	23.2	37.6	>100	>100	>100	31.5	27.0	45.1	36.1	44.2	109.4	30.8	36.6	42.7
2017	19.8	21.9	34.8	>100	>100	>100	30.7	26.4	44.0	33.3	40.0	71.0	29.1	34.1	39.9
2018	17.4	19.2	29.6	>100	>100	>100	25.3	22.1	34.4	28.2	32.8	48.6	25.0	28.6	33.2
2019	15.5	17.1	25.8	>100	>100	>100	22.3	19.5	29.9	24.3	27.7	38.7	21.8	24.6	28.7
2020	14.0	15.5	23.1	>100	>100	>100	20.2	17.7	26.8	21.3	24.0	32.4	19.6	21.9	25.6
2021	13.2	14.6	21.6	>100	>100	>100	19.0	16.7	25.2	19.8	22.1	29.4	18.4	20.5	23.9
2022	11.4	12.5	18.2	>100	>100	>100	16.3	14.4	21.2	17.1	18.9	24.6	15.9	17.5	20.3
2023	10.9	12.0	17.5	>100	>100	>100	15.7	13.9	20.4	16.7	18.5	24.1	15.2	16.7	19.5
2024	10.5	11.6	16.8	>100	>100	>100	15.1	13.3	19.7	15.8	17.5	22.7	14.6	16.0	18.8
2025	10.0	11.0	15.9	>100	>100	>100	14.3	12.6	18.5	14.7	16.2	20.8	13.8	15.1	17.7
2026	9.6	10.6	15.3	>100	>100	>100	13.7	12.1	17.7	14.0	15.4	19.7	13.3	14.5	17.0
2027	9.2	10.2	14.6	>100	>100	>100	13.2	11.7	17.0	13.5	14.8	18.9	12.8	13.9	16.3
2028	8.8	9.7	13.9	69.3	>100	>100	12.6	11.1	16.2	13.2	14.4	18.4	12.2	13.2	15.4
2029	8.3	9.1	13.0	53.3	>100	>100	11.8	10.5	15.2	12.7	13.9	17.7	11.5	12.4	14.5
2030	8.2	9.0	12.8	51.3	>100	>100	11.7	10.3	14.9	12.4	13.5	17.1	11.3	12.2	14.3
2031	8.7	9.6	13.8	62.3	>100	>100	12.3	10.9	15.9	12.2	13.4	16.9	12.0	13.0	15.2
2032	8.8	9.7	14.0	66.0	>100	>100	12.5	11.0	16.1	11.4	12.4	15.6	12.1	13.2	15.5
2033	8.6	9.4	13.5	58.2	>100	>100	12.2	10.8	15.7	11.5	12.5	15.7	11.8	12.8	15.0
2034	8.5	9.3	13.3	56.1	>100	>100	12.0	10.6	15.4	11.2	12.2	15.3	11.6	12.6	14.8
2035	8.2	9.0	12.8	50.2	>100	>100	11.6	10.3	14.9	11.5	12.5	15.8	11.2	12.2	14.2

Table 32: Discounted payback periods for residential customers, low-range battery costs, TOU end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	13.6	14.9	21.7	>100	>100	>100	21.6	18.9	28.7	25.0	28.6	40.5	23.3	26.4	31.0
2016	15.1	16.7	25.5	>100	>100	>100	21.7	18.9	29.4	23.9	27.1	38.3	20.9	23.5	27.7
2017	9.5	10.2	13.2	24.7	28.4	34.0	12.3	11.3	14.5	12.7	13.5	15.7	11.8	12.5	13.8
2018	8.5	9.2	12.1	22.6	26.1	31.7	10.9	10.0	13.1	11.5	12.2	14.4	10.7	11.3	12.7
2019	7.7	8.4	11.2	20.7	23.9	29.6	10.1	9.2	12.3	10.6	11.2	13.4	9.8	10.3	11.8
2020	6.9	7.6	10.3	18.6	21.7	27.3	9.2	8.3	11.4	9.5	10.1	12.2	8.8	9.3	10.9
2021	6.4	7.1	9.7	17.2	20.2	25.7	8.7	7.8	10.8	8.8	9.4	11.4	8.2	8.7	10.2
2022	5.7	6.3	8.8	15.6	18.3	23.5	7.8	7.0	9.9	8.0	8.5	10.5	7.5	7.9	9.3
2023	5.5	6.1	8.5	15.1	17.7	22.9	7.6	6.8	9.6	7.9	8.4	10.3	7.2	7.6	9.1
2024	5.3	5.9	8.3	14.6	17.2	22.4	7.4	6.6	9.4	7.6	8.1	10.0	7.0	7.4	8.9
2025	5.1	5.7	8.0	14.1	16.6	21.7	7.1	6.3	9.1	7.2	7.7	9.5	6.7	7.1	8.5
2026	5.0	5.5	7.8	13.7	16.2	21.2	6.9	6.1	8.8	7.0	7.4	9.2	6.5	6.9	8.3
2027	4.8	5.4	7.6	13.3	15.7	20.7	6.7	5.9	8.6	6.8	7.2	9.0	6.3	6.6	8.1
2028	4.6	5.1	7.3	12.8	15.2	20.0	6.5	5.7	8.3	6.7	7.1	8.8	6.1	6.4	7.8
2029	4.4	4.9	7.0	12.3	14.5	19.2	6.2	5.5	8.0	6.5	6.9	8.6	5.8	6.1	7.5
2030	4.3	4.8	6.9	12.2	14.4	19.1	6.1	5.4	7.9	6.4	6.7	8.4	5.8	6.0	7.4
2031	4.5	5.1	7.2	12.6	14.9	19.8	6.4	5.6	8.2	6.3	6.7	8.4	6.0	6.3	7.7
2032	4.6	5.1	7.3	12.7	15.0	19.9	6.4	5.7	8.3	6.0	6.3	7.9	6.1	6.4	7.8
2033	4.5	5.0	7.1	12.4	14.7	19.5	6.3	5.6	8.1	6.0	6.4	8.0	5.9	6.2	7.6
2034	4.4	5.0	7.1	12.4	14.7	19.4	6.2	5.5	8.0	5.9	6.3	7.8	5.9	6.2	7.6
2035	4.3	4.8	6.9	12.1	14.3	19.0	6.1	5.4	7.8	6.0	6.4	8.0	5.7	6.0	7.4

Table 33: Discounted payback periods for residential customers, mid-range battery costs, TOU(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	24.7	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	31.2	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	29.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	25.6	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	22.7	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2020	20.6	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2021	19.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2022	16.4	>100	58.5	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2023	15.8	>100	51.8	>100	>100	>100	>100	>100	>100	92.8	>100	>100	>100	>100	>100
2024	15.3	>100	47.3	>100	>100	>100	>100	>100	>100	64.6	>100	>100	>100	>100	>100
2025	14.5	>100	41.4	>100	>100	>100	>100	>100	>100	49.7	60.5	>100	>100	>100	>100
2026	14.0	71.4	38.2	>100	>100	>100	>100	>100	>100	43.6	50.8	>100	>100	>100	>100
2027	13.4	58.8	35.3	>100	>100	>100	>100	>100	>100	40.4	46.2	>100	>100	>100	>100
2028	12.7	49.4	32.1	>100	>100	>100	>100	>100	>100	38.2	43.1	>100	>100	>100	>100
2029	12.0	42.2	29.0	>100	>100	>100	73.0	>100	>100	35.8	40.1	>100	>100	>100	>100
2030	11.8	40.9	28.4	>100	>100	>100	66.4	>100	>100	33.8	37.6	>100	>100	>100	>100
2031	12.6	49.0	31.8	>100	>100	>100	>100	>100	>100	33.2	36.7	>100	>100	>100	>100
2032	12.8	51.0	32.5	>100	>100	>100	>100	>100	>100	29.2	32.0	>100	>100	>100	>100
2033	12.4	46.3	30.7	>100	>100	>100	99.1	>100	>100	29.5	32.3	>100	>100	>100	>100
2034	12.3	44.9	30.1	>100	>100	>100	82.6	>100	>100	28.3	30.9	>100	>100	>100	>100
2035	11.8	40.7	28.2	>100	>100	>100	64.8	>100	>100	29.6	32.5	>100	>100	>100	>100

Table 34: Discounted payback periods for residential customers, low-range battery costs, TOU(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	19.4	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	22.6	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	20.0	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	17.4	>100	84.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	15.6	>100	51.4	>100	>100	>100	>100	>100	>100	67.5	>100	>100	>100	>100	>100
2020	13.9	>100	38.7	>100	>100	>100	>100	>100	>100	42.6	49.0	>100	>100	>100	>100
2021	12.8	61.6	33.2	>100	>100	>100	>100	>100	>100	35.3	39.1	>100	>100	>100	>100
2022	11.1	41.0	26.5	>100	>100	>100	64.4	98.4	>100	28.5	31.0	>100	85.8	>100	>100
2023	10.7	38.2	25.1	>100	>100	>100	56.6	72.5	>100	27.7	30.0	>100	66.5	>100	>100
2024	10.4	36.2	24.1	>100	>100	>100	51.4	62.1	>100	25.8	27.8	>100	57.7	>100	>100
2025	9.9	33.1	22.5	>100	>100	>100	44.8	51.8	>100	23.5	25.1	69.3	48.7	>100	>100
2026	9.6	31.3	21.4	>100	72.4	>100	41.2	46.8	>100	22.0	23.6	56.4	44.3	>100	>100
2027	9.2	29.4	20.4	>100	59.8	>100	38.2	42.7	>100	21.2	22.6	50.9	40.5	>100	>100
2028	8.8	27.1	19.1	>100	50.2	>100	34.7	38.3	>100	20.4	21.7	46.9	36.4	>100	>100
2029	8.3	25.0	17.8	88.3	43.0	>100	31.4	34.4	>100	19.6	20.9	43.6	32.8	81.7	>100
2030	8.2	24.5	17.5	79.7	41.8	>100	30.6	33.4	>100	18.9	20.1	40.7	31.9	71.7	>100
2031	8.7	27.1	19.0	>100	47.8	>100	33.8	37.2	>100	18.7	19.8	39.7	35.7	>100	>100
2032	8.8	27.6	19.2	>100	49.1	>100	34.7	38.3	>100	17.1	18.1	34.1	36.6	>100	>100
2033	8.6	26.2	18.5	>100	45.1	>100	32.9	36.2	>100	17.2	18.2	34.4	34.6	>100	>100
2034	8.5	25.8	18.3	>100	44.0	>100	32.2	35.3	>100	16.7	17.7	32.9	33.7	99.1	>100
2035	8.2	24.4	17.4	74.1	40.5	>100	30.3	33.0	>100	17.3	18.3	34.7	31.6	69.0	>100

Table 35: Discounted payback periods for residential customers, mid-range battery costs, capacity tariff end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2020	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2021	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2022	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2023	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2024	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2025	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2026	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2027	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2028	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2029	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2030	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2031	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2032	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2033	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2034	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2035	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100

Table 36: Discounted payback periods for residential customers, low-range battery costs, capacity tariff end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	>100	>100	>100	>100	>100	>100	>100	>100	0.0	>100	>100	>100	>100	>100	>100
2016	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2020	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2021	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2022	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2023	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2024	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2025	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2026	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2027	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2028	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2029	>100	>100	>100	73.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2030	>100	>100	>100	68.8	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2031	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2032	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2033	>100	>100	>100	91.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2034	>100	>100	>100	83.0	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2035	>100	>100	>100	66.2	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100

Table 37: Discounted payback periods for residential customers, mid-range battery costs, Flat(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**
2015	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2020	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2021	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2022	>100	>100	>100	60.5	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2023	>100	>100	>100	51.4	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2024	>100	>100	>100	45.7	>100	>100	68.3	88.0	>100	>100	>100	>100	>100	>100	>100
2025	>100	>100	>100	39.7	>100	>100	51.9	59.7	>100	>100	>100	>100	>100	>100	>100
2026	>100	>100	>100	36.3	>100	>100	45.2	51.1	>100	>100	>100	>100	>100	>100	>100
2027	>100	>100	>100	33.4	>100	>100	40.4	45.1	>100	>100	>100	>100	>100	>100	>100
2028	>100	>100	>100	30.4	>100	>100	35.8	39.6	>100	>100	>100	>100	>100	>100	>100
2029	>100	>100	>100	27.3	70.2	>100	31.5	34.6	>100	>100	>100	>100	>100	>100	>100
2030	>100	>100	>100	26.6	64.4	>100	30.4	33.4	>100	>100	>100	>100	>100	>100	>100
2031	>100	>100	>100	29.0	>100	>100	33.7	37.5	>100	>100	>100	>100	>100	>100	>100
2032	>100	>100	>100	29.3	>100	>100	34.6	38.5	>100	59.9	>100	>100	>100	>100	>100
2033	>100	>100	>100	27.8	76.5	>100	32.5	36.0	>100	60.8	>100	>100	>100	>100	>100
2034	>100	>100	>100	27.2	69.4	>100	31.5	34.8	>100	53.7	>100	>100	>100	>100	>100
2035	>100	>100	>100	25.6	57.4	>100	29.3	32.3	>100	60.2	>100	>100	>100	>100	>100

Table 38: Discounted payback periods for residential customers, low-range battery costs, Flat(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**	**Large**	**Medium**	**Small**
2015	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	>100	>100	>100	92.6	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	>100	>100	>100	48.6	>100	>100	81.5	>100	>100	>100	>100	>100	>100	>100	>100
2020	>100	>100	>100	35.2	>100	>100	45.7	62.4	>100	>100	>100	>100	>100	>100	>100
2021	>100	>100	>100	29.5	>100	>100	36.8	47.5	>100	>100	>100	>100	>100	>100	>100
2022	>100	>100	>100	23.4	53.5	>100	27.9	34.3	>100	73.8	>100	>100	>100	>100	>100
2023	>100	>100	>100	22.0	46.6	>100	26.1	32.0	>100	63.6	>100	>100	>100	>100	>100
2024	>100	>100	>100	20.8	42.1	>100	24.5	30.2	>100	50.6	>100	>100	>100	>100	>100
2025	>100	>100	>100	19.3	37.3	>100	22.4	27.5	>100	40.7	>100	>100	>100	>100	>100
2026	>100	>100	>100	18.4	34.4	>100	21.1	25.9	>100	36.0	>100	>100	>100	>100	>100
2027	>100	>100	>100	17.4	31.8	>100	19.9	24.3	>100	33.4	>100	>100	>100	>100	>100
2028	>100	>100	>100	16.3	29.0	>100	18.5	22.5	>100	31.2	>100	>100	>100	>100	>100
2029	>100	>100	>100	15.2	26.2	>100	17.1	20.8	>100	29.4	>100	>100	>100	>100	>100
2030	>100	>100	>100	14.9	25.6	>100	16.6	20.2	>100	27.7	>100	>100	>100	>100	>100
2031	>100	>100	>100	15.8	27.7	>100	17.8	21.8	>100	27.0	87.9	>100	>100	>100	>100
2032	>100	>100	>100	15.9	28.0	>100	18.0	22.2	>100	23.8	53.3	>100	>100	>100	>100
2033	>100	>100	>100	15.3	26.5	>100	17.3	21.2	>100	23.9	53.7	>100	>100	>100	>100
2034	>100	>100	>100	15.1	26.0	>100	17.0	20.8	>100	22.9	48.7	>100	>100	>100	>100
2035	>100	>100	>100	14.4	24.6	>100	16.2	19.7	>100	23.8	53.5	>100	>100	>100	>100

Table 39: Discounted payback periods for residential customers, mid-range battery costs, TOU(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	11.0	25.0	23.0	22.5	30.8	>100	11.8	14.1	17.1	35.2	39.9	68.3	13.8	20.1	19.5
2016	14.8	37.1	33.0	24.3	32.2	>100	14.1	16.6	20.3	46.0	54.3	>100	15.1	21.7	21.3
2017	13.8	33.6	30.0	21.6	28.0	>100	13.6	16.1	19.7	39.6	45.2	>100	14.3	20.4	20.1
2018	12.6	29.4	26.4	20.3	25.6	>100	12.3	14.4	17.5	33.4	37.1	59.8	13.2	18.6	18.4
2019	11.9	26.7	23.9	19.1	23.5	>100	11.6	13.6	16.5	29.7	32.4	47.7	12.4	17.2	17.2
2020	11.2	24.4	21.9	18.0	21.7	>100	11.1	12.8	15.6	26.2	28.3	39.5	11.7	16.1	16.2
2021	10.8	23.0	20.7	17.3	20.6	75.4	10.7	12.4	15.0	24.4	26.3	35.9	11.3	15.4	15.6
2022	7.9	17.1	15.4	12.4	14.9	36.6	8.2	9.6	11.7	17.3	18.6	24.2	8.6	11.9	12.0
2023	7.7	16.6	14.9	12.2	14.5	34.9	8.0	9.4	11.5	17.2	18.4	23.9	8.4	11.6	11.7
2024	7.6	16.2	14.6	12.0	14.2	33.8	7.9	9.2	11.3	16.5	17.6	22.8	8.3	11.4	11.5
2025	7.3	15.5	13.9	11.6	13.7	31.7	7.6	8.9	10.8	15.4	16.5	21.2	8.0	10.9	11.0
2026	7.1	15.0	13.4	11.4	13.3	30.4	7.4	8.6	10.5	14.8	15.7	20.2	7.8	10.6	10.8
2027	6.9	14.5	13.0	11.1	13.0	29.1	7.2	8.4	10.2	14.4	15.3	19.5	7.5	10.3	10.4
2028	6.7	13.8	12.4	10.7	12.5	27.4	7.0	8.1	9.9	14.0	14.9	19.0	7.3	9.9	10.0
2029	6.4	13.0	11.7	10.3	11.9	25.5	6.7	7.8	9.4	13.7	14.5	18.5	7.0	9.4	9.6
2030	6.3	12.9	11.6	10.2	11.8	25.3	6.6	7.7	9.3	13.3	14.1	18.0	6.9	9.3	9.5
2031	6.7	13.8	12.4	10.7	12.4	27.3	6.9	8.1	9.8	13.2	14.0	17.7	7.3	9.8	10.0
2032	6.8	14.0	12.5	10.8	12.5	27.7	7.0	8.2	9.9	12.2	12.9	16.3	7.3	9.9	10.1
2033	6.5	13.5	12.1	10.5	12.1	26.4	6.8	7.9	9.6	12.3	13.0	16.3	7.1	9.7	9.8
2034	6.5	13.3	11.9	10.3	12.0	26.0	6.7	7.8	9.5	11.9	12.6	15.9	7.0	9.5	9.7
2035	6.2	12.8	11.5	10.0	11.6	24.8	6.5	7.6	9.2	12.2	13.0	16.4	6.8	9.2	9.4

Table 40: Discounted payback periods for residential customers, low-range battery costs, TOU(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	9.9	21.4	19.4	20.3	25.5	>100	11.8	14.1	17.1	28.4	31.1	45.3	12.3	17.4	17.3
2016	13.2	29.4	26.0	21.8	26.3	>100	14.1	16.6	20.3	34.3	37.6	63.4	13.4	18.4	18.6
2017	11.9	25.8	22.7	18.9	22.1	>100	13.6	16.1	19.7	28.9	31.2	46.4	12.2	16.7	17.0
2018	10.9	22.7	20.0	17.7	20.1	69.7	12.3	14.4	17.5	24.9	26.6	37.5	11.2	15.0	15.5
2019	10.2	20.9	18.3	16.7	18.6	53.8	11.6	13.6	16.5	22.5	23.9	33.0	10.5	14.0	14.6
2020	9.5	18.9	16.6	15.6	17.0	44.0	11.1	12.8	15.6	19.8	20.9	28.3	9.8	12.9	13.6
2021	9.0	17.7	15.5	14.9	16.0	39.2	10.7	12.4	15.0	18.4	19.3	25.8	9.4	12.2	12.9
2022	6.5	13.4	11.6	10.7	11.6	26.1	8.2	9.6	11.7	13.2	13.9	18.4	7.1	9.4	9.9
2023	6.4	13.0	11.3	10.4	11.3	25.2	8.0	9.4	11.5	13.1	13.7	18.2	6.9	9.2	9.7
2024	6.3	12.8	11.1	10.3	11.1	24.6	7.9	9.2	11.3	12.6	13.2	17.5	6.8	9.0	9.5
2025	6.1	12.2	10.6	10.0	10.8	23.5	7.6	8.9	10.8	11.9	12.5	16.4	6.6	8.6	9.2
2026	5.9	11.9	10.3	9.8	10.5	22.8	7.4	8.6	10.5	11.5	12.0	15.8	6.4	8.4	9.0
2027	5.8	11.5	10.0	9.6	10.2	22.0	7.2	8.4	10.2	11.2	11.7	15.3	6.2	8.2	8.7
2028	5.6	11.0	9.5	9.3	9.9	20.9	7.0	8.1	9.9	10.9	11.4	15.0	6.0	7.9	8.4
2029	5.3	10.5	9.1	8.9	9.5	19.7	6.7	7.8	9.4	10.7	11.2	14.6	5.8	7.5	8.0
2030	5.3	10.4	9.0	8.9	9.4	19.6	6.6	7.7	9.3	10.5	10.9	14.2	5.7	7.5	8.0
2031	5.6	11.0	9.6	9.3	9.9	20.9	6.9	8.1	9.8	10.3	10.8	14.1	6.0	7.9	8.4
2032	5.6	11.2	9.7	9.4	9.9	21.1	7.0	8.2	9.9	9.6	10.0	13.0	6.1	7.9	8.5
2033	5.5	10.8	9.3	9.1	9.6	20.3	6.8	7.9	9.6	9.6	10.0	13.0	5.9	7.7	8.2
2034	5.4	10.6	9.2	9.0	9.5	20.0	6.7	7.8	9.5	9.4	9.8	12.7	5.8	7.6	8.1
2035	5.2	10.2	8.9	8.7	9.2	19.2	6.5	7.6	9.2	9.6	10.0	13.0	5.6	7.4	7.9

Table 41: Discounted payback periods for residential customers, mid-range battery costs, Flat(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	10.2	13.8	26.1	12.2	14.1	20.5	8.6	7.0	9.8	12.4	13.8	17.9	11.2	14.3	15.8
2016	14.0	18.8	39.0	16.1	18.6	28.0	11.2	9.1	12.4	17.0	18.9	24.8	15.2	19.4	21.5
2017	12.2	16.3	31.6	14.1	16.2	23.9	9.9	8.1	11.1	14.8	16.3	21.2	13.2	16.8	18.6
2018	11.3	15.0	28.2	13.0	14.9	21.8	9.2	7.6	10.3	13.6	15.1	19.4	12.3	15.4	17.2
2019	10.9	14.4	26.3	12.3	14.1	20.6	8.8	7.3	9.9	13.0	14.4	18.4	11.8	14.7	16.5
2020	10.4	13.7	24.8	11.7	13.4	19.5	8.4	7.0	9.5	12.4	13.7	17.5	11.3	14.0	15.8
2021	10.2	13.3	23.9	11.4	13.0	18.9	8.2	6.9	9.2	12.1	13.4	17.0	11.0	13.6	15.4
2022	7.2	9.8	18.0	8.6	9.9	14.8	6.2	5.2	7.3	8.8	9.8	12.7	8.0	10.1	11.6
2023	6.9	9.4	16.9	8.2	9.4	14.0	5.9	5.0	7.0	8.3	9.3	12.0	7.7	9.6	11.1
2024	6.6	8.9	16.0	7.8	8.9	13.3	5.6	4.8	6.7	8.0	8.9	11.4	7.3	9.2	10.5
2025	6.4	8.5	15.1	7.4	8.5	12.6	5.4	4.6	6.4	7.6	8.5	10.9	7.0	8.8	10.1
2026	6.2	8.3	14.6	7.2	8.3	12.2	5.3	4.5	6.2	7.4	8.3	10.6	6.8	8.5	9.8
2027	6.1	8.2	14.3	7.1	8.1	11.9	5.2	4.4	6.1	7.3	8.1	10.3	6.7	8.4	9.6
2028	6.0	8.0	13.9	6.9	7.9	11.7	5.1	4.3	6.0	7.1	7.9	10.1	6.6	8.2	9.4
2029	5.9	7.9	13.6	6.8	7.8	11.4	5.0	4.2	5.9	7.0	7.8	9.9	6.5	8.0	9.2
2030	5.8	7.6	13.1	6.6	7.6	11.0	4.9	4.1	5.7	6.8	7.5	9.6	6.3	7.8	9.0
2031	5.5	7.3	12.5	6.4	7.2	10.5	4.7	4.0	5.5	6.5	7.2	9.2	6.1	7.5	8.6
2032	5.3	7.0	11.9	6.1	6.9	10.1	4.5	3.8	5.3	6.3	6.9	8.8	5.8	7.2	8.2
2033	5.1	6.8	11.5	5.9	6.7	9.7	4.3	3.7	5.1	6.0	6.7	8.5	5.6	6.9	7.9
2034	5.0	6.6	11.1	5.7	6.5	9.5	4.2	3.6	5.0	5.9	6.5	8.2	5.5	6.7	7.7
2035	4.8	6.4	10.8	5.6	6.3	9.2	4.1	3.5	4.8	5.7	6.3	8.0	5.3	6.5	7.5

Table 42: Discounted payback periods for residential customers, low-range battery costs, Flat(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	9.6	12.7	23.2	11.1	12.7	18.5	7.9	6.6	9.0	11.6	12.8	16.4	10.5	13.1	14.8
2016	13.2	17.2	32.8	14.5	16.5	24.5	10.3	8.5	11.3	15.8	17.4	22.3	14.2	17.6	19.9
2017	11.3	14.6	26.4	12.3	14.0	20.6	8.9	7.4	9.9	13.4	14.8	18.7	12.2	14.9	17.0
2018	10.4	13.5	23.6	11.3	12.7	18.7	8.2	6.9	9.2	12.4	13.6	17.1	11.3	13.7	15.7
2019	10.0	12.9	22.2	10.7	12.1	17.8	7.8	6.6	8.8	11.8	13.0	16.2	10.8	13.0	15.0
2020	9.6	12.2	20.7	10.1	11.3	16.7	7.4	6.3	8.3	11.2	12.3	15.3	10.3	12.3	14.3
2021	9.3	11.8	19.9	9.7	10.9	16.1	7.2	6.1	8.0	10.9	11.9	14.8	10.0	11.9	13.9
2022	6.5	8.6	15.0	7.2	8.2	12.5	5.3	4.5	6.3	7.7	8.6	11.0	7.2	8.7	10.4
2023	6.2	8.2	14.2	6.8	7.8	11.9	5.0	4.4	6.0	7.4	8.2	10.4	6.8	8.3	9.9
2024	6.0	7.8	13.4	6.5	7.4	11.3	4.8	4.2	5.7	7.0	7.8	9.9	6.5	7.9	9.5
2025	5.7	7.5	12.8	6.3	7.1	10.8	4.6	4.0	5.5	6.7	7.5	9.5	6.3	7.6	9.1
2026	5.6	7.3	12.4	6.1	6.9	10.5	4.5	3.9	5.4	6.6	7.3	9.2	6.1	7.4	8.8
2027	5.5	7.2	12.1	6.0	6.8	10.2	4.5	3.9	5.3	6.5	7.1	9.0	6.0	7.3	8.7
2028	5.4	7.0	11.9	5.9	6.6	10.0	4.4	3.8	5.2	6.3	7.0	8.8	5.9	7.1	8.5
2029	5.4	6.9	11.6	5.8	6.5	9.8	4.3	3.7	5.1	6.2	6.9	8.7	5.8	7.0	8.3
2030	5.2	6.7	11.2	5.6	6.3	9.5	4.2	3.7	4.9	6.1	6.7	8.4	5.7	6.8	8.1
2031	5.0	6.5	10.7	5.4	6.1	9.1	4.0	3.5	4.7	5.8	6.4	8.0	5.4	6.5	7.8
2032	4.8	6.2	10.3	5.2	5.8	8.7	3.9	3.4	4.6	5.6	6.2	7.7	5.2	6.2	7.4
2033	4.6	6.0	9.9	5.0	5.6	8.4	3.7	3.3	4.4	5.4	5.9	7.4	5.0	6.0	7.2
2034	4.5	5.8	9.6	4.9	5.5	8.2	3.6	3.2	4.3	5.2	5.8	7.2	4.9	5.9	7.0
2035	4.4	5.6	9.3	4.7	5.3	7.9	3.5	3.1	4.2	5.1	5.6	7.0	4.8	5.7	6.8

11.2 Payback periods for commercial end-use cases

Table 43: Discounted payback periods for commercial customers, mid-range battery costs, TOU end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	18.2	18.4	18.9	>100	>100	>100	16.4	16.6	17.1	>100	>100	>100	42.1	43.2	46.1
2016	21.7	22.0	22.7	>100	>100	>100	17.1	17.3	17.8	>100	>100	>100	38.4	39.2	41.6
2017	20.5	20.7	21.4	>100	>100	>100	16.8	17.0	17.5	>100	>100	>100	35.6	36.3	38.3
2018	18.0	18.2	18.9	>100	>100	>100	14.5	14.7	15.1	57.1	59.9	69.0	29.5	30.1	31.5
2019	16.0	16.2	16.7	>100	>100	>100	13.1	13.2	13.6	41.4	42.6	45.9	25.3	25.7	26.8
2020	14.5	14.7	15.1	>100	>100	>100	12.0	12.1	12.5	33.3	34.0	36.1	22.4	22.8	23.7
2021	13.6	13.8	14.2	>100	>100	>100	11.4	11.5	11.9	29.8	30.4	32.1	20.8	21.2	22.1
2022	11.7	11.9	12.2	>100	>100	>100	10.0	10.1	10.4	24.5	24.9	26.2	17.7	18.0	18.7
2023	11.3	11.4	11.8	>100	>100	>100	9.6	9.8	10.1	23.8	24.2	25.4	17.0	17.2	17.9
2024	10.8	11.0	11.4	>100	>100	>100	9.3	9.4	9.7	22.2	22.6	23.7	16.2	16.5	17.1
2025	10.3	10.4	10.7	>100	>100	>100	8.8	8.9	9.2	20.2	20.6	21.5	15.3	15.5	16.1
2026	9.9	10.0	10.3	>100	>100	>100	8.5	8.6	8.9	19.0	19.4	20.2	14.6	14.9	15.4
2027	9.5	9.6	9.9	>100	>100	>100	8.2	8.3	8.6	18.3	18.6	19.4	14.0	14.2	14.8
2028	9.0	9.2	9.5	>100	>100	>100	7.8	7.9	8.2	17.7	18.0	18.8	13.3	13.5	14.0
2029	8.5	8.6	8.9	>100	>100	>100	7.4	7.5	7.8	17.0	17.3	18.1	12.5	12.7	13.2
2030	8.4	8.5	8.8	>100	>100	>100	7.3	7.4	7.7	16.5	16.7	17.4	12.3	12.5	13.0
2031	8.9	9.1	9.4	>100	>100	>100	7.7	7.8	8.0	16.3	16.5	17.2	13.1	13.3	13.8
2032	9.1	9.2	9.5	>100	>100	>100	7.8	7.9	8.2	15.0	15.3	15.9	13.3	13.5	14.0
2033	8.8	8.9	9.2	>100	>100	>100	7.6	7.7	8.0	15.1	15.4	16.0	12.9	13.1	13.6
2034	8.7	8.8	9.1	>100	>100	>100	7.5	7.6	7.9	14.7	15.0	15.5	12.7	12.9	13.4
2035	8.4	8.5	8.8	>100	>100	>100	7.3	7.4	7.6	15.2	15.4	16.0	12.3	12.5	12.9

Table 44: Discounted payback periods for commercial customers, low-range battery costs, TOU end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	14.0	14.2	14.6	>100	>100	>100	12.7	12.9	13.3	43.5	44.9	48.7	27.1	27.6	28.9
2016	15.6	15.8	16.3	>100	>100	>100	12.7	12.8	13.3	39.4	40.5	43.7	24.0	24.4	25.5
2017	13.6	13.8	14.3	>100	>100	>100	11.5	11.6	12.0	30.9	31.6	33.6	20.5	20.8	21.8
2018	11.7	11.9	12.3	>100	>100	>100	9.7	9.9	10.2	24.6	25.1	26.5	17.2	17.5	18.3
2019	10.3	10.5	10.9	>100	>100	>100	8.7	8.8	9.1	20.7	21.1	22.2	15.0	15.3	15.9
2020	9.0	9.1	9.5	>100	>100	>100	7.6	7.8	8.1	17.0	17.3	18.2	12.9	13.1	13.7
2021	8.2	8.3	8.7	>100	>100	>100	7.0	7.1	7.4	15.0	15.3	16.1	11.6	11.8	12.4
2022	7.1	7.3	7.6	>100	>100	>100	6.2	6.3	6.5	13.0	13.3	14.0	10.2	10.4	10.8
2023	6.8	7.0	7.3	>100	>100	>100	5.9	6.0	6.3	12.7	12.9	13.6	9.7	9.9	10.4
2024	6.6	6.7	7.0	>100	>100	>100	5.7	5.8	6.1	11.9	12.2	12.8	9.3	9.5	10.0
2025	6.2	6.4	6.6	>100	>100	>100	5.4	5.5	5.8	11.1	11.3	11.9	8.8	9.0	9.4
2026	6.0	6.1	6.4	>100	>100	>100	5.2	5.3	5.6	10.6	10.8	11.3	8.5	8.7	9.1
2027	5.8	5.9	6.2	>100	>100	>100	5.1	5.2	5.4	10.2	10.4	11.0	8.2	8.3	8.8
2028	5.5	5.6	5.9	>100	>100	>100	4.8	4.9	5.1	9.9	10.1	10.6	7.8	7.9	8.3
2029	5.2	5.3	5.6	95.3	>100	>100	4.6	4.7	4.9	9.6	9.8	10.3	7.4	7.5	7.9
2030	5.2	5.2	5.5	81.7	>100	>100	4.5	4.6	4.8	9.3	9.5	10.0	7.3	7.4	7.8
2031	5.4	5.5	5.8	>100	>100	>100	4.7	4.8	5.0	9.2	9.4	9.9	7.6	7.8	8.2
2032	5.5	5.6	5.9	>100	>100	>100	4.8	4.9	5.1	8.6	8.8	9.2	7.7	7.9	8.3
2033	5.4	5.5	5.7	>100	>100	>100	4.7	4.8	5.0	8.6	8.8	9.3	7.5	7.7	8.1
2034	5.3	5.4	5.7	>100	>100	>100	4.6	4.7	4.9	8.4	8.6	9.0	7.5	7.6	8.0
2035	5.1	5.2	5.5	74.0	92.4	>100	4.5	4.6	4.8	8.6	8.8	9.3	7.2	7.3	7.7

Table 45: Discounted payback periods for commercial customers, mid-range battery costs, TOU(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	69.1	75.0	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2020	50.5	52.6	59.2	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2021	43.8	45.3	49.6	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2022	32.8	33.6	35.7	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2023	31.0	31.7	33.6	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2024	29.5	30.2	31.9	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2025	27.2	27.8	29.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2026	25.8	26.4	27.8	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2027	24.4	24.9	26.2	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2028	22.8	23.3	24.4	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2029	21.1	21.5	22.5	>100	>100	>100	75.2	85.4	>100	>100	>100	>100	>100	>100	>100
2030	20.7	21.1	22.1	>100	>100	>100	67.8	74.3	>100	>100	>100	>100	>100	>100	>100
2031	22.7	23.1	24.2	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2032	23.0	23.5	24.7	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2033	22.1	22.5	23.6	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2034	21.8	22.2	23.2	>100	>100	>100	86.4	>100	>100	>100	>100	>100	>100	>100	>100
2035	20.7	21.1	22.0	>100	>100	>100	66.3	72.3	>100	>100	>100	>100	>100	>100	>100

Table 46: Discounted payback periods for commercial customers, low-range battery costs, TOU(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	43.8	45.3	49.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	67.5	73.2	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	47.1	49.0	54.7	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	36.2	37.3	40.2	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2019	30.4	31.2	33.3	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2020	25.7	26.3	27.9	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2021	23.0	23.6	24.9	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100	>100
2022	19.4	19.8	20.8	>100	>100	>100	51.4	54.5	65.4	>100	>100	>100	>100	>100	>100
2023	18.5	18.9	19.9	>100	>100	>100	46.5	48.9	56.5	>100	>100	>100	>100	>100	>100
2024	17.9	18.2	19.2	>100	>100	>100	42.7	44.7	50.6	>100	>100	>100	>100	>100	>100
2025	16.9	17.2	18.1	>100	>100	>100	38.1	39.6	44.0	>100	>100	>100	>100	>100	>100
2026	16.2	16.5	17.4	>100	>100	>100	35.4	36.7	40.4	80.0	>100	>100	>100	>100	>100
2027	15.5	15.8	16.6	>100	>100	>100	33.1	34.2	37.4	65.1	72.6	>100	>100	>100	>100
2028	14.7	15.0	15.7	>100	>100	>100	30.4	31.4	34.0	57.2	61.9	83.2	>100	>100	>100
2029	13.8	14.1	14.7	>100	>100	>100	27.8	28.6	30.8	51.6	55.1	67.6	>100	>100	>100
2030	13.6	13.8	14.5	>100	>100	>100	27.1	27.9	30.0	47.2	49.9	58.6	>100	>100	>100
2031	14.6	14.9	15.6	>100	>100	>100	29.6	30.5	33.0	45.8	48.2	56.1	>100	>100	>100
2032	14.8	15.1	15.8	>100	>100	>100	30.3	31.2	33.8	38.4	40.0	44.6	>100	>100	>100
2033	14.3	14.5	15.3	>100	>100	>100	28.9	29.8	32.2	38.8	40.4	45.2	>100	>100	>100
2034	14.1	14.4	15.1	>100	>100	>100	28.4	29.2	31.5	36.9	38.3	42.5	>100	>100	>100
2035	13.5	13.8	14.5	>100	>100	>100	26.9	27.6	29.7	39.1	40.8	45.7	>100	>100	>100

Table 47: Discounted payback periods for commercial customers, mid-range battery costs, Standard tariff end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	41.4	67.7	>100	8.4	9.6	13.4	46.6	>100	>100	17.9	21.4	36.9	>100	>100	>100
2016	69.7	>100	>100	7.7	9.7	13.6	53.4	73.9	>100	18.1	21.7	38.1	>100	>100	>100
2017	57.5	96.0	>100	7.3	9.4	13.3	51.4	63.2	>100	17.3	20.7	36.0	>100	>100	>100
2018	43.2	50.2	>100	6.9	8.6	12.3	37.9	46.7	>100	15.6	18.7	31.5	>100	>100	>100
2019	35.4	40.8	>100	6.4	8.0	11.5	32.2	38.5	>100	14.1	16.9	28.1	>100	>100	>100
2020	30.7	35.4	>100	6.0	7.4	10.7	28.5	33.6	>100	12.8	15.4	25.1	>100	>100	>100
2021	28.2	32.7	>100	5.8	7.1	10.2	26.5	31.0	>100	12.1	14.5	23.5	>100	>100	>100
2022	23.0	26.6	85.4	5.2	6.4	9.2	22.1	25.6	69.3	10.8	12.8	20.4	>100	>100	>100
2023	22.0	25.5	69.7	5.1	6.3	9.2	21.2	24.6	60.6	10.6	12.7	20.2	>100	>100	>100
2024	21.1	24.4	61.4	4.9	6.1	8.9	20.4	23.6	55.2	10.2	12.2	19.3	>100	>100	>100
2025	19.8	22.8	51.6	4.8	5.8	8.4	19.1	22.1	47.8	9.5	11.4	18.0	>100	>100	>100
2026	18.9	21.8	46.8	4.6	5.6	8.1	18.3	21.1	43.9	9.2	10.9	17.2	82.9	>100	>100
2027	18.0	20.8	42.8	4.5	5.4	7.9	17.5	20.2	40.4	8.9	10.6	16.6	63.9	>100	>100
2028	17.0	19.7	38.7	4.4	5.3	7.7	16.6	19.1	36.8	8.7	10.4	16.2	52.8	>100	>100
2029	15.9	18.4	34.7	4.2	5.2	7.6	15.6	17.9	33.2	8.4	10.1	15.7	44.5	94.3	>100
2030	15.6	18.0	33.7	4.1	5.1	7.4	15.3	17.6	32.3	8.2	9.8	15.3	42.8	83.7	>100
2031	16.9	19.3	37.7	4.3	5.0	7.3	16.3	18.9	36.3	8.2	9.7	15.1	50.7	>100	>100
2032	17.1	19.6	38.9	4.3	4.7	6.9	16.5	19.2	37.4	7.6	9.1	14.0	53.1	>100	>100
2033	16.5	19.0	36.8	4.2	4.8	6.9	16.1	18.5	35.3	7.7	9.1	14.1	48.5	>100	>100
2034	16.3	18.7	35.8	4.2	4.7	6.7	15.8	18.2	34.4	7.5	8.9	13.7	46.6	>100	>100
2035	15.6	18.0	33.6	4.1	4.8	6.9	15.2	17.5	32.2	7.7	9.2	14.1	42.4	79.6	>100

Table 48: Discounted payback periods for commercial customers, low-range battery costs, Standard tariff end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	28.5	38.5	>100	7.0	8.2	11.7	30.8	42.9	>100	14.4	17.3	29.0	>100	>100	>100
2016	34.8	40.0	>100	6.3	8.0	11.7	31.3	37.2	>100	14.0	16.9	28.7	>100	>100	>100
2017	29.1	35.0	>100	5.7	7.4	10.9	27.7	31.9	>100	12.6	15.3	25.9	>100	>100	>100
2018	24.3	27.8	>100	5.2	6.7	10.0	22.4	26.8	>100	11.2	13.6	22.9	>100	>100	>100
2019	21.1	24.4	79.7	4.8	6.2	9.4	19.8	23.6	66.6	10.1	12.4	20.8	>100	>100	>100
2020	18.2	21.4	53.6	4.4	5.6	8.6	17.3	20.6	48.9	8.9	11.0	18.5	59.8	>100	>100
2021	16.6	19.6	45.4	4.1	5.2	8.1	15.8	18.9	42.0	8.2	10.2	17.1	45.5	>100	>100
2022	14.2	16.9	35.1	3.7	4.8	7.4	13.8	16.4	33.4	7.4	9.1	15.2	34.4	52.9	>100
2023	13.6	16.3	33.4	3.6	4.7	7.3	13.3	15.9	31.8	7.3	9.0	15.1	32.2	47.6	>100
2024	13.2	15.8	32.0	3.5	4.5	7.1	12.8	15.3	30.6	7.0	8.7	14.5	30.3	44.0	>100
2025	12.5	15.0	29.7	3.4	4.3	6.7	12.1	14.6	28.5	6.6	8.2	13.7	27.9	39.8	>100
2026	12.0	14.4	28.2	3.3	4.2	6.5	11.7	14.1	27.2	6.3	7.9	13.1	26.4	37.3	>100
2027	11.6	13.9	26.8	3.2	4.1	6.4	11.3	13.5	25.9	6.2	7.7	12.7	25.0	34.9	>100
2028	11.0	13.2	25.1	3.1	4.0	6.2	10.7	12.9	24.3	6.0	7.5	12.4	23.3	32.2	>100
2029	10.4	12.5	23.3	3.0	3.9	6.1	10.2	12.2	22.6	5.9	7.3	12.1	21.6	29.4	>100
2030	10.2	12.3	22.9	3.0	3.8	5.9	10.0	12.0	22.2	5.7	7.1	11.8	21.2	29.0	>100
2031	10.9	13.0	24.7	3.1	3.8	5.9	10.6	12.7	24.1	5.7	7.0	11.7	22.9	31.5	>100
2032	11.0	13.2	25.2	3.1	3.5	5.5	10.7	12.9	24.5	5.3	6.6	10.9	23.3	32.1	>100
2033	10.7	12.8	24.3	3.0	3.6	5.6	10.4	12.5	23.6	5.3	6.6	10.9	22.4	30.6	>100
2034	10.6	12.6	23.8	3.0	3.5	5.5	10.3	12.4	23.2	5.2	6.5	10.7	22.0	30.1	>100
2035	10.2	12.2	22.8	2.9	3.6	5.6	10.0	11.9	22.1	5.4	6.7	11.0	21.0	28.6	>100

Table 49: Discounted payback periods for commercial customers, mid-range battery costs, Standard(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	72.8	100.7	>100	32.1	33.9	44.4	>100	>100	>100	>100	>100	>100	>100	>100	>100
2016	>100	>100	>100	27.5	34.0	44.9	>100	>100	>100	>100	>100	>100	>100	>100	>100
2017	>100	>100	>100	24.8	31.4	40.5	>100	>100	>100	>100	>100	>100	>100	>100	>100
2018	67.0	50.3	>100	22.0	26.4	33.1	>100	>100	>100	54.1	62.0	>100	>100	>100	>100
2019	45.0	38.7	59.1	19.3	22.7	28.0	>100	>100	>100	39.8	43.2	77.8	>100	>100	>100
2020	36.3	32.7	45.5	17.4	19.8	24.1	>100	>100	>100	32.1	34.4	49.1	>100	>100	>100
2021	32.4	29.8	40.2	16.3	18.3	22.3	>100	>100	>100	28.8	30.7	41.8	>100	>100	>100
2022	25.5	24.2	31.0	14.1	15.8	19.0	>100	>100	>100	23.7	25.1	32.4	68.7	61.2	>100
2023	24.0	23.0	29.2	13.5	15.4	18.6	93.3	69.4	>100	23.0	24.3	31.4	57.0	52.7	>100
2024	22.8	21.8	27.6	13.0	14.6	17.6	66.1	57.3	>100	21.5	22.7	28.9	49.6	46.9	>100
2025	21.1	20.2	25.5	12.3	13.5	16.3	51.8	47.4	>100	19.6	20.6	26.0	42.4	41.2	81.3
2026	20.0	19.3	24.1	11.9	12.9	15.4	45.8	42.6	>100	18.4	19.4	24.3	38.7	38.0	64.6
2027	19.0	18.4	22.9	11.5	12.4	14.9	41.3	38.8	68.7	17.7	18.6	23.2	35.5	35.3	55.3
2028	17.8	17.4	21.5	11.0	12.1	14.5	37.1	35.1	55.1	17.1	18.0	22.4	32.4	32.5	48.0
2029	16.6	16.2	19.9	10.4	11.7	14.0	33.0	31.5	45.8	16.5	17.3	21.5	29.3	29.4	41.4
2030	16.3	15.9	19.5	10.3	11.3	13.6	32.0	30.6	43.9	15.9	16.7	20.7	28.5	28.9	40.4
2031	17.6	16.9	20.9	10.8	11.2	13.4	35.3	34.0	52.3	15.7	16.5	20.4	31.4	31.4	45.7
2032	17.8	17.2	21.3	10.9	10.5	12.5	36.4	34.9	55.0	14.6	15.3	18.7	32.2	32.0	47.1
2033	17.2	16.7	20.6	10.6	10.5	12.5	34.6	33.1	50.0	14.7	15.4	18.8	30.7	30.6	43.9
2034	17.0	16.4	20.3	10.5	10.3	12.2	33.7	32.3	48.0	14.3	15.0	18.3	30.0	30.1	42.9
2035	16.2	15.8	19.4	10.2	10.6	12.6	31.6	30.3	43.4	14.7	15.4	18.9	28.2	28.6	39.8

Table 50: Discounted payback periods for commercial customers, low-range battery costs, Standard(PV) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	34.3	36.7	53.6	22.2	23.3	28.9	>100	>100	>100	41.7	45.6	99.6	>100	>100	>100
2016	42.1	36.3	54.0	18.6	22.0	27.3	>100	>100	>100	37.7	41.0	70.2	>100	>100	>100
2017	32.1	30.1	41.9	15.6	18.8	23.2	>100	>100	>100	29.6	31.7	45.2	>100	>100	>100
2018	25.2	23.2	30.6	13.6	15.8	19.5	99.6	74.8	>100	23.6	25.1	33.7	58.5	54.3	>100
2019	21.1	19.8	25.7	11.9	13.7	17.0	47.9	44.9	>100	19.8	21.0	27.6	39.8	38.6	78.8
2020	17.4	16.7	21.6	10.3	11.6	14.4	33.9	32.7	55.0	16.2	17.2	22.3	29.8	29.4	45.2
2021	15.4	14.9	19.3	9.3	10.4	13.0	28.4	27.5	42.0	14.3	15.2	19.7	25.3	25.1	36.6
2022	13.0	12.8	16.5	8.2	9.2	11.5	23.0	22.6	32.1	12.4	13.2	16.9	20.9	20.8	29.0
2023	12.4	12.2	15.7	7.8	8.9	11.2	21.6	21.2	29.9	12.0	12.8	16.5	19.7	19.6	27.2
2024	11.8	11.7	15.0	7.5	8.5	10.6	20.2	20.0	28.1	11.3	12.0	15.5	18.5	18.6	25.6
2025	11.1	11.0	14.2	7.2	7.9	9.9	18.8	18.6	25.8	10.5	11.2	14.4	17.3	17.5	23.9
2026	10.7	10.6	13.6	6.9	7.5	9.5	17.8	17.7	24.4	10.0	10.6	13.7	16.4	16.7	22.8
2027	10.2	10.2	13.1	6.7	7.3	9.2	17.0	16.9	23.1	9.7	10.3	13.2	15.7	16.0	21.7
2028	9.6	9.6	12.4	6.4	7.1	8.9	15.9	15.9	21.6	9.3	9.9	12.8	14.8	15.1	20.4
2029	9.1	9.1	11.7	6.1	6.9	8.7	14.9	14.9	20.0	9.0	9.6	12.4	13.8	14.2	19.1
2030	8.9	9.0	11.5	6.0	6.7	8.4	14.6	14.6	19.6	8.8	9.3	12.0	13.6	14.0	18.8
2031	9.5	9.4	12.1	6.3	6.6	8.4	15.4	15.5	21.1	8.7	9.2	11.9	14.4	14.8	20.0
2032	9.6	9.5	12.3	6.3	6.2	7.8	15.7	15.7	21.5	8.1	8.6	11.1	14.6	14.9	20.2
2033	9.3	9.3	11.9	6.2	6.2	7.9	15.2	15.2	20.7	8.2	8.7	11.1	14.2	14.5	19.5
2034	9.2	9.2	11.8	6.1	6.1	7.7	15.0	15.0	20.4	8.0	8.5	10.8	14.0	14.4	19.3
2035	8.9	8.9	11.4	6.0	6.3	7.9	14.4	14.4	19.4	8.2	8.7	11.1	13.4	13.9	18.6

Table 51: Discounted payback periods for commercial customers, mid-range battery costs, TOU(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	28.8	29.0	32.7	37.8	38.1	38.8	17.1	15.3	15.3	42.7	43.1	21.4	27.4	27.5	24.5
2016	43.9	44.2	54.8	87.3	91.1	105.7	22.1	19.5	19.4	>100	>100	29.1	40.0	40.3	34.3
2017	34.4	34.6	40.0	49.0	49.5	50.8	19.2	17.1	17.1	59.3	60.1	24.6	32.1	32.3	28.4
2018	29.9	30.1	34.1	40.0	40.3	41.2	17.5	15.7	15.6	45.7	46.2	22.2	28.2	28.4	25.3
2019	27.3	27.5	30.8	35.5	35.8	36.5	16.4	14.7	14.7	39.9	40.2	20.7	25.9	26.0	23.3
2020	25.3	25.5	28.3	32.3	32.5	33.1	15.5	13.9	13.9	35.8	36.1	19.4	24.0	24.2	21.8
2021	24.2	24.4	27.1	30.6	30.8	31.3	15.0	13.5	13.5	33.8	34.0	18.7	23.0	23.2	20.9
2022	18.3	18.4	20.1	22.1	22.2	22.5	12.0	10.9	10.9	23.8	24.0	14.6	17.7	17.8	16.3
2023	17.1	17.2	18.7	20.5	20.6	20.9	11.3	10.3	10.3	22.0	22.1	13.7	16.5	16.6	15.3
2024	16.1	16.1	17.5	19.1	19.2	19.5	10.7	9.8	9.8	20.5	20.6	13.0	15.5	15.6	14.4
2025	15.1	15.2	16.5	17.9	18.0	18.2	10.1	9.3	9.3	19.1	19.2	12.3	14.6	14.7	13.6
2026	14.6	14.7	15.9	17.2	17.3	17.5	9.8	9.0	9.0	18.4	18.5	11.9	14.1	14.2	13.1
2027	14.2	14.3	15.5	16.7	16.8	17.0	9.6	8.8	8.8	17.8	17.9	11.6	13.7	13.8	12.8
2028	13.8	13.9	15.0	16.3	16.4	16.6	9.4	8.6	8.6	17.3	17.4	11.3	13.4	13.4	12.5
2029	13.5	13.5	14.6	15.8	15.9	16.1	9.2	8.4	8.4	16.8	16.9	11.0	13.0	13.1	12.1
2030	13.0	13.1	14.1	15.2	15.3	15.5	8.9	8.2	8.2	16.2	16.3	10.6	12.6	12.6	11.7
2031	12.4	12.5	13.4	14.5	14.5	14.7	8.5	7.8	7.8	15.3	15.4	10.2	12.0	12.0	11.2
2032	11.9	11.9	12.8	13.8	13.9	14.0	8.2	7.5	7.5	14.6	14.7	9.7	11.5	11.5	10.7
2033	11.4	11.5	12.3	13.2	13.3	13.5	7.9	7.2	7.2	14.0	14.1	9.4	11.0	11.1	10.3
2034	11.1	11.1	11.9	12.8	12.9	13.1	7.7	7.1	7.1	13.6	13.6	9.1	10.7	10.8	10.0
2035	10.7	10.7	11.5	12.4	12.5	12.6	7.4	6.8	6.8	13.1	13.2	8.8	10.4	10.4	9.7

Table 52: Discounted payback periods for commercial customers, low-range battery costs, TOU(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	24.1	24.3	26.9	30.4	30.6	31.1	17.1	15.3	15.3	33.7	33.9	18.7	23.1	23.2	21.0
2016	33.4	33.6	38.7	47.2	47.7	49.0	22.1	19.5	19.4	57.4	58.3	24.4	31.2	31.4	27.7
2017	26.2	26.3	29.4	33.8	34.0	34.7	19.2	17.1	17.1	38.1	38.4	20.1	24.8	25.0	22.5
2018	23.0	23.1	25.6	28.9	29.0	29.5	17.5	15.7	15.6	32.0	32.2	18.1	21.9	22.0	20.0
2019	21.2	21.4	23.5	26.3	26.5	26.9	16.4	14.7	14.7	29.0	29.2	16.9	20.3	20.4	18.6
2020	19.5	19.6	21.4	23.8	24.0	24.4	15.5	13.9	13.9	26.1	26.3	15.7	18.6	18.7	17.1
2021	18.4	18.5	20.3	22.5	22.6	22.9	15.0	13.5	13.5	24.5	24.7	15.0	17.6	17.7	16.3
2022	14.0	14.1	15.2	16.5	16.6	16.9	12.0	10.9	10.9	17.9	18.0	11.6	13.6	13.6	12.7
2023	13.1	13.2	14.3	15.5	15.6	15.8	11.3	10.3	10.3	16.7	16.8	11.0	12.8	12.8	11.9
2024	12.4	12.5	13.5	14.6	14.7	14.9	10.7	9.8	9.8	15.7	15.8	10.4	12.0	12.1	11.3
2025	11.8	11.8	12.8	13.8	13.9	14.1	10.1	9.3	9.3	14.8	14.9	9.9	11.4	11.5	10.7
2026	11.4	11.5	12.4	13.3	13.4	13.6	9.8	9.0	9.0	14.3	14.4	9.6	11.1	11.1	10.4
2027	11.2	11.2	12.1	13.0	13.1	13.3	9.6	8.8	8.8	13.9	14.0	9.4	10.8	10.9	10.1
2028	10.9	10.9	11.8	12.7	12.7	12.9	9.4	8.6	8.6	13.5	13.6	9.1	10.5	10.6	9.9
2029	10.6	10.7	11.5	12.4	12.4	12.6	9.2	8.4	8.4	13.2	13.3	8.9	10.3	10.4	9.7
2030	10.3	10.4	11.1	12.0	12.0	12.2	8.9	8.2	8.2	12.8	12.8	8.7	10.0	10.0	9.4
2031	9.8	9.9	10.6	11.4	11.5	11.6	8.5	7.8	7.8	12.1	12.2	8.3	9.5	9.6	9.0
2032	9.4	9.5	10.2	10.9	11.0	11.1	8.2	7.5	7.5	11.6	11.7	8.0	9.1	9.2	8.6
2033	9.1	9.1	9.8	10.5	10.5	10.7	7.9	7.2	7.2	11.2	11.2	7.7	8.8	8.8	8.3
2034	8.8	8.9	9.5	10.2	10.2	10.4	7.7	7.1	7.1	10.8	10.9	7.5	8.6	8.6	8.1
2035	8.5	8.6	9.2	9.8	9.9	10.0	7.4	6.8	6.8	10.5	10.5	7.2	8.3	8.3	7.8

Table 53: Discounted payback periods for commercial customers, mid-range battery costs, Standard(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	7.8	9.8	14.4	9.0	9.9	12.7	6.8	5.8	7.6	9.1	9.8	11.6	8.4	10.0	10.7
2016	9.9	12.0	17.0	10.9	11.9	14.9	8.4	7.2	9.1	11.3	12.1	14.0	10.5	12.2	13.0
2017	9.0	11.0	15.7	9.9	10.9	13.8	7.7	6.5	8.4	10.3	11.0	12.9	9.5	11.2	11.9
2018	8.5	10.4	14.9	9.4	10.3	13.1	7.2	6.2	7.9	9.7	10.4	12.2	9.0	10.6	11.4
2019	8.2	10.1	14.5	9.0	9.9	12.7	7.0	6.0	7.7	9.4	10.1	11.8	8.8	10.2	11.1
2020	8.0	9.8	14.0	8.7	9.6	12.3	6.7	5.8	7.4	9.1	9.8	11.5	8.5	9.9	10.7
2021	7.8	9.6	13.8	8.5	9.4	12.1	6.6	5.7	7.3	8.9	9.6	11.3	8.3	9.7	10.6
2022	6.0	7.6	11.7	6.9	7.7	10.3	5.2	4.5	6.0	7.0	7.6	9.2	6.5	7.8	8.7
2023	5.7	7.3	11.2	6.6	7.4	9.9	5.0	4.3	5.8	6.7	7.3	8.9	6.2	7.5	8.3
2024	5.5	7.1	10.8	6.3	7.1	9.5	4.8	4.1	5.5	6.4	7.0	8.5	6.0	7.2	8.0
2025	5.3	6.8	10.4	6.1	6.8	9.2	4.6	4.0	5.3	6.2	6.8	8.2	5.8	7.0	7.8
2026	5.2	6.7	10.2	6.0	6.6	9.0	4.5	3.9	5.2	6.1	6.6	8.1	5.7	6.8	7.6
2027	5.2	6.6	10.0	5.9	6.5	8.8	4.5	3.9	5.1	6.0	6.5	7.9	5.6	6.7	7.5
2028	5.1	6.5	9.9	5.8	6.4	8.7	4.4	3.8	5.1	5.9	6.4	7.8	5.5	6.6	7.4
2029	5.0	6.4	9.7	5.7	6.3	8.5	4.3	3.7	5.0	5.8	6.3	7.6	5.4	6.5	7.2
2030	4.9	6.2	9.5	5.5	6.2	8.3	4.2	3.7	4.9	5.7	6.2	7.5	5.3	6.3	7.1
2031	4.7	6.0	9.1	5.3	5.9	8.0	4.1	3.5	4.7	5.5	5.9	7.2	5.1	6.1	6.8
2032	4.6	5.8	8.8	5.2	5.7	7.8	3.9	3.4	4.5	5.3	5.7	7.0	4.9	5.9	6.6
2033	4.4	5.6	8.6	5.0	5.6	7.6	3.8	3.3	4.4	5.1	5.6	6.8	4.8	5.7	6.4
2034	4.3	5.5	8.4	4.9	5.5	7.4	3.7	3.2	4.3	5.0	5.4	6.6	4.7	5.6	6.3
2035	4.2	5.4	8.2	4.8	5.3	7.2	3.6	3.1	4.2	4.9	5.3	6.4	4.5	5.4	6.1

Table 54: Discounted payback periods for commercial customers, low-range battery costs, Standard(IPSS) end-use case

	NSW			QLD			SA			TAS			VIC		
Year	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small	Large	Medium	Small
2015	7.5	9.3	13.5	8.4	9.2	11.9	6.4	5.5	7.1	8.6	9.3	11.0	8.0	9.5	10.3
2016	9.5	11.4	16.0	10.1	11.1	14.0	7.9	6.8	8.5	10.7	11.4	13.3	10.0	11.5	12.4
2017	8.5	10.2	14.5	9.0	9.9	12.7	7.0	6.1	7.7	9.6	10.3	12.0	9.0	10.3	11.3
2018	8.0	9.6	13.7	8.5	9.3	12.0	6.6	5.7	7.2	9.1	9.7	11.3	8.5	9.7	10.7
2019	7.7	9.3	13.2	8.1	8.9	11.6	6.4	5.5	7.0	8.8	9.4	10.9	8.2	9.4	10.4
2020	7.5	9.0	12.7	7.8	8.5	11.1	6.1	5.3	6.7	8.4	9.0	10.5	7.9	9.0	10.0
2021	7.3	8.8	12.4	7.6	8.2	10.9	5.9	5.2	6.5	8.2	8.8	10.3	7.7	8.8	9.8
2022	5.4	6.8	10.4	5.9	6.6	9.2	4.5	4.0	5.3	6.3	6.8	8.3	5.9	6.9	8.0
2023	5.2	6.6	10.0	5.7	6.3	8.8	4.4	3.8	5.1	6.0	6.6	8.0	5.7	6.7	7.7
2024	5.1	6.3	9.6	5.5	6.1	8.5	4.2	3.7	4.9	5.8	6.3	7.7	5.5	6.4	7.4
2025	4.9	6.1	9.3	5.3	5.8	8.2	4.0	3.6	4.7	5.6	6.1	7.4	5.3	6.2	7.1
2026	4.8	6.0	9.1	5.1	5.7	8.0	4.0	3.5	4.6	5.5	6.0	7.2	5.2	6.1	7.0
2027	4.7	5.9	8.9	5.1	5.6	7.9	3.9	3.4	4.5	5.4	5.9	7.1	5.1	6.0	6.9
2028	4.7	5.8	8.8	5.0	5.5	7.7	3.8	3.4	4.4	5.3	5.8	7.0	5.0	5.9	6.8
2029	4.6	5.7	8.6	4.9	5.4	7.6	3.8	3.3	4.4	5.2	5.7	6.9	4.9	5.8	6.7
2030	4.5	5.6	8.4	4.8	5.3	7.4	3.7	3.3	4.3	5.1	5.6	6.7	4.8	5.6	6.5
2031	4.3	5.4	8.1	4.6	5.1	7.2	3.6	3.2	4.1	4.9	5.4	6.5	4.7	5.4	6.3
2032	4.2	5.2	7.9	4.5	4.9	6.9	3.4	3.0	4.0	4.8	5.2	6.3	4.5	5.3	6.1
2033	4.1	5.1	7.6	4.3	4.8	6.7	3.3	3.0	3.9	4.6	5.0	6.1	4.4	5.1	5.9
2034	4.0	4.9	7.5	4.2	4.7	6.6	3.3	2.9	3.8	4.5	4.9	5.9	4.3	5.0	5.8
2035	3.8	4.8	7.3	4.1	4.6	6.4	3.2	2.8	3.7	4.4	4.8	5.8	4.1	4.8	5.6

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