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Grid vs Garage

A comparison of battery deployment models in providing low voltage network support and other services

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Glossary

Term	Definition
AECOM	AECOM Australia Pty Ltd
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
Asset life	The length of time before the battery capacity drops below 80% of its nameplate capacity
Augex	Augmentation expenditure
Bankability	The willingness of well-established financial institutions to finance a project or proposal at a reasonable interest rate
BESS	Battery Energy Storage System
BNEF	Bloomberg New Energy Finance
Capacity	The energy that can be stored in the battery
Capex	Capital expenditure
CCI	Controlled Commercial and Industrial battery
C&I	Commercial and Industrial
Commercial benefits	The commercial benefits provided to the owner or operator of the BESS
CR	Controlled Residential battery
DER	Distributed Energy Resource
Dispatch time	The length of time that a battery can discharge energy for at its maximum rated power (rated output)
DNSP	Distribution Network Service Provider
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
Garage BESS	Behind the meter BESS
GW	Gigawatt (equivalent to 1,000,000,000 watts)
GWh	Gigawatt-hour (equivalent to 1,000,000,000 watt-hours)
Grid BESS	In front of meter BESS
HV	High Voltage
ISP	Integrated System Plan
kW	Kilowatt (equivalent to 1,000 watts)
kWh	Kilowatt-hour (equivalent to 1,000 watt-hours)
LCOE	Levelised Cost of Energy
Li-ion	Lithium-ion
LV	Low Voltage
MV	Medium Voltage
MVAr	Mega volt amps (reactive)
MW	Megawatt (equivalent to 1,000,000 watts)
MWh	Megawatt-hour (equivalent to 1,000,000 watt-hours)

Term	Definition
NEM	National Electricity Market
NCCI	Non-Controlled Commercial and Industrial battery
NCR	Non-Controlled Residential
NPV	Net Present Value
NSCAS	Network Support and Control Ancillary Services
Opex	Operational expenditure
PPA	Power Purchasing Agreement
PV	Photovoltaic
Rated output	The magnitude of instantaneous power that can be drawn from the battery
SRAS	System Restart Ancillary Service
Syncon	Synchronous Condenser
System benefits	The socioeconomic benefits provided to the overall system by the BESS, supporting the network and consumers
T&D	Transmission and Distribution
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer Reliability
VOM	Variable Operations and Maintenance
VRE	Variable Renewable Energy

Executive summary

Australia's future energy system will feature greater levels of energy storage such as utility and domestic scale battery energy storage systems (BESS). BESS are considered critical to support increased penetration of variable renewable energy and promote better system reliability and security.

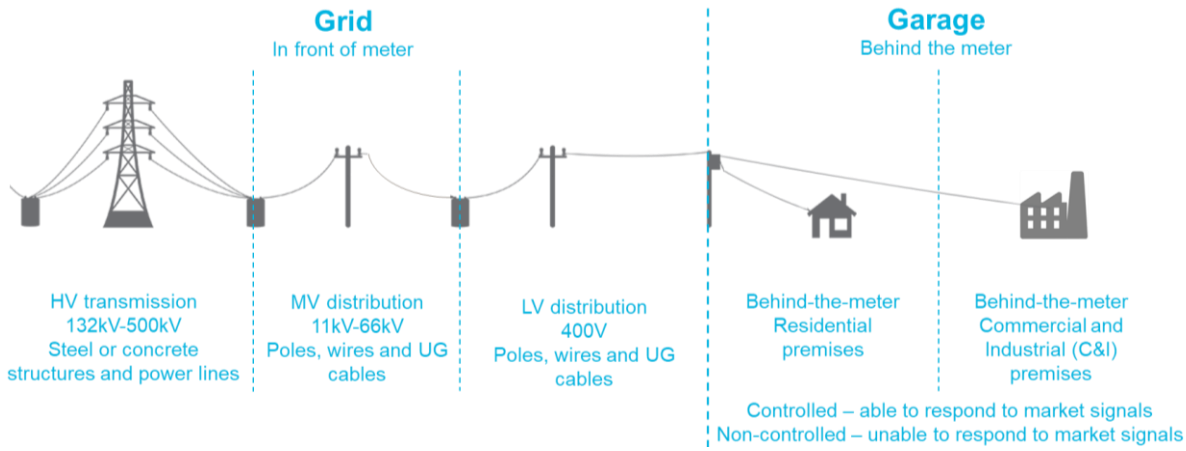
BESS can be connected at different points within the electricity supply chain, as shown in Figure 1. They can be installed in front of the meter on the high, medium and low voltage components of the network (grid BESS), as well as behind the meter on residential and commercial premises (garage BESS). Garage BESS can be either controlled or non-controlled depending on whether they have the technical and operation ability to respond to market signals.

The location at which BESS are connected on the network influences its capacity to deliver network services such as managing load peaks and supporting frequency, voltage and system strength. It also affects the commercial returns that asset owners can receive.

Our analysis of BESS deployment options at different connection points found:

1. There is a diversity of market and commercial benefits from BESS deployment
2. BESS on the low voltage network provide greatest benefit
3. Controlled BESS create additional value for the system and asset owners.

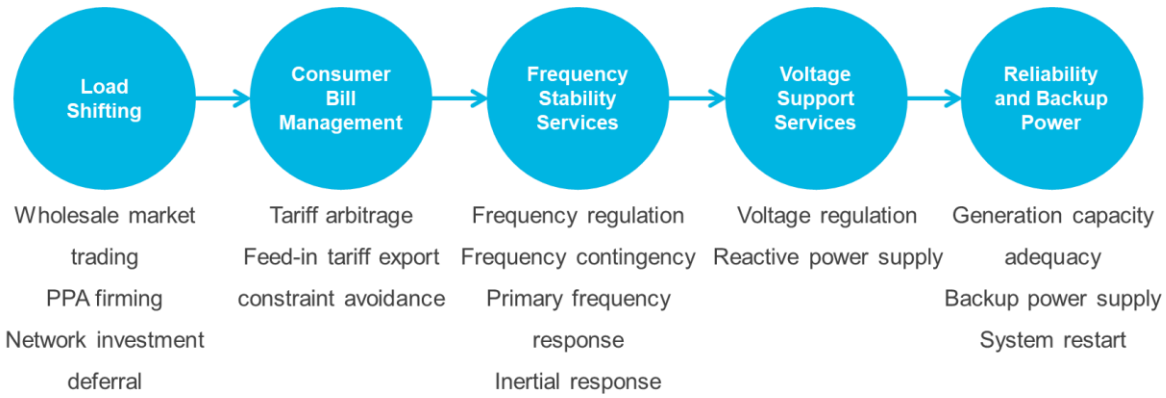
Figure 1 BESS connection option configurations within electricity supply chain



BESS value streams and value stacking

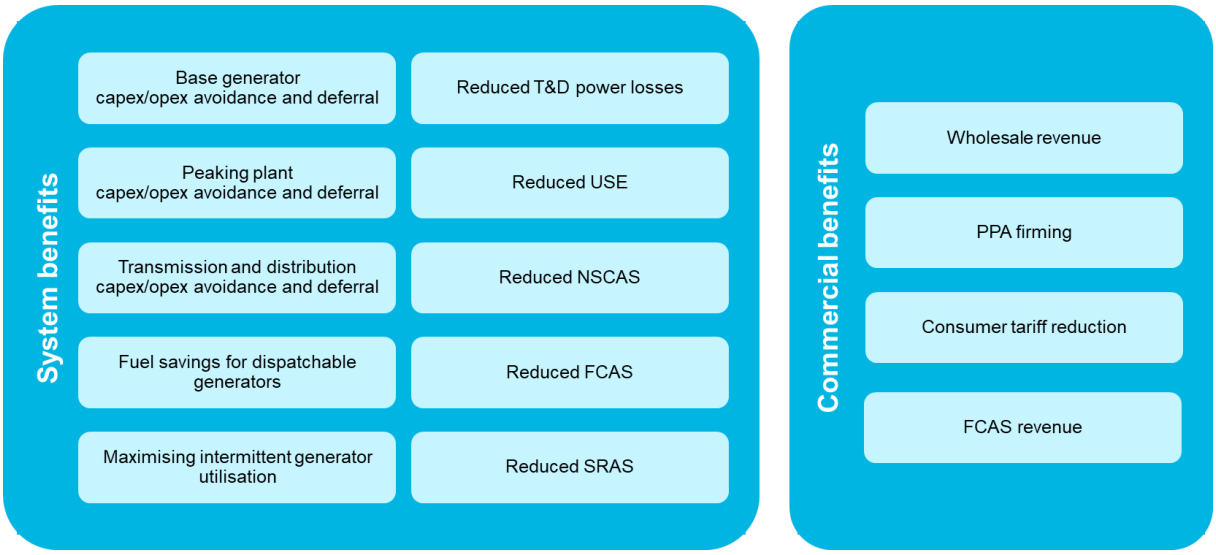
BESS can provide a wide range of services, outlined in Figure 2.

Figure 2 High-level battery services



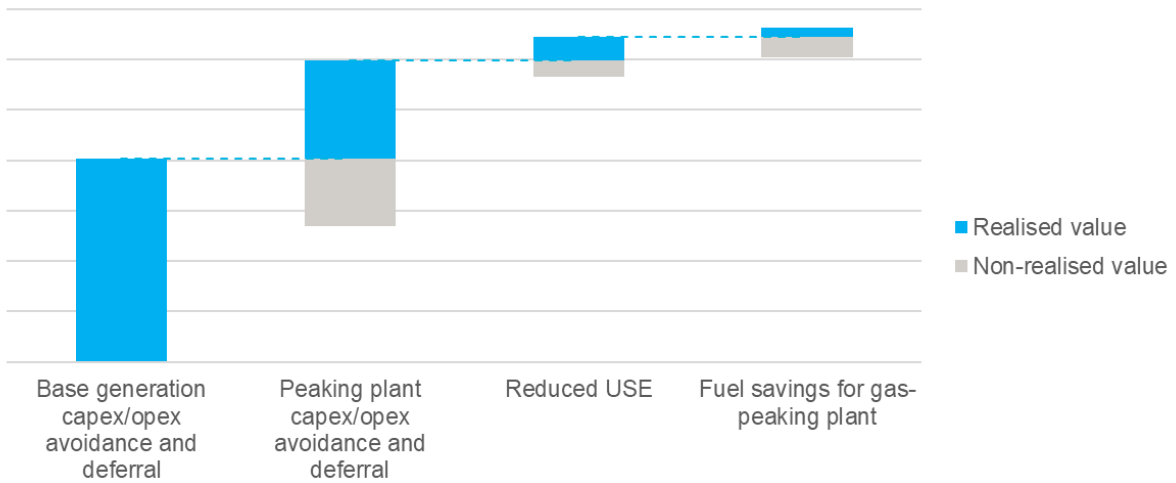
These services may deliver benefits across multiple value streams, defined in Figure 3. These value streams can provide system benefits for electricity networks and consumers or commercial benefits to asset owners, either simultaneously or by switching between services in response to technical needs or commercial incentives. Importantly, not all value streams can be accessed by a single BESS asset because of operational or market constraints.

Figure 3 BESS system and commercial benefits and value streams



There are multiple ways that BESS services can be stacked to provide economic benefit the system or commercial benefits to the asset owner. This means that the revenue that may be realised by a BESS is not simply the sum of the available revenue streams, as shown in Figure 4. The driver for value stacking will ultimately depend on the asset operators' priorities and approach to risk. It may require a complex trade-off analysis to optimise returns.

Figure 4 BESS value stack principle (example)



Approach

Seven BESS deployment pathways, shown in Figure 5, were assessed in the context of four different electricity market scenarios, outlined in Figure 6. This analysis considers one possible value stack which prioritises services based on the bankability of services. This recognises the ability of a BESS project to realise commercial returns for relevant services and secure finance at acceptable rates. This value stack is likely to reflect the overall investment in BESS, as it considers the risk and uncertainty that investors face in getting projects off the ground.

Figure 5 BESS deployment pathways

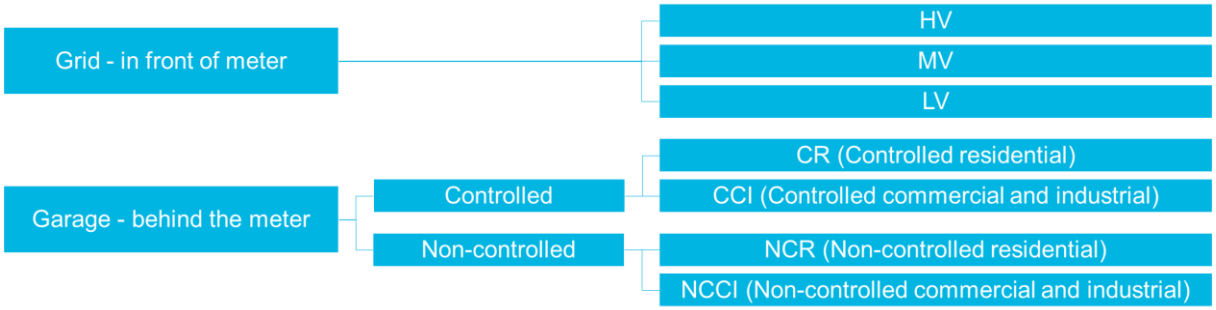


Figure 6 Electricity market scenarios and sources

	Low	Medium	High	Rapid transformation
Source	ISP Slow	ISP Neutral	ISP Fast	BNEF NEO
Emissions reduction	28%	28%	52%	42%
Battery aggregation 2050	90%	50%	10%	90%
VRE cost reductions	Slow	Neutral	Neutral	Rapid
Gas prices	Neutral	Weak	Strong	Neutral

Findings

In general, pathways perform better the higher the level of electricity consumption. This is shown in Figure 8 and Figure 9 with pathway benefits plotted on the y-axis, costs on the x-axis and the size of each bubble reflecting benefit cost ratios. The ideal position is in the top left quadrant with high benefits and low costs. Relative pathway performance is generally maintained across all scenarios for system benefits, as shown in Figure 8.

Finding 1: There is a diversity of market and commercial benefits from BESS deployment

Grid BESS provide different value streams than garage BESS, across all deployment pathways and electricity market scenarios, as outlined in Figure 7.

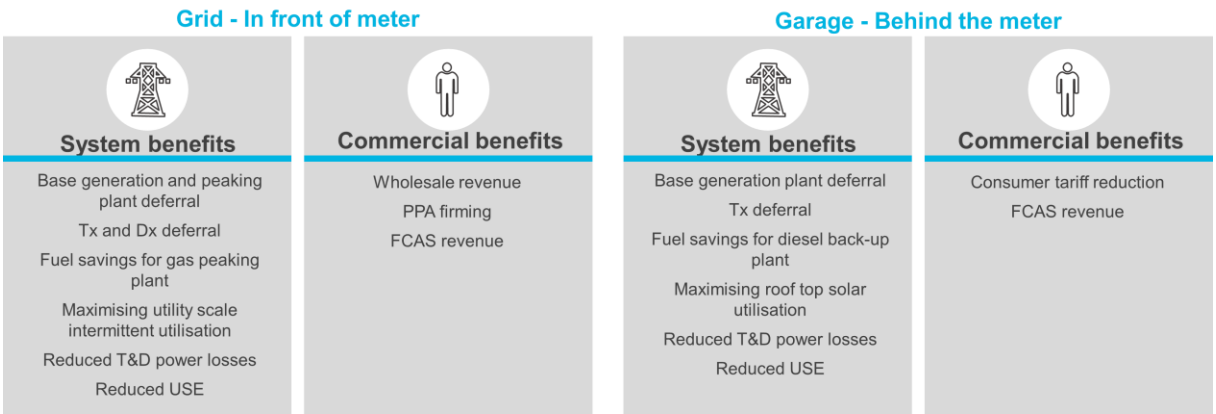
Grid and garage BESS provide some similar value streams, including deferring base generation plant and transmission augmentation expenditure (augex), reducing T&D power losses and reducing USE. Grid and garage BESS are likely to compete to provide the services that realise these values. However, they each provide a number of value stream benefits for which they would not need to compete.

In particular, grid BESS maximise the utilisation of utility scale wind and solar, whereas garage BESS maximise the utilisation of roof-top solar, and neither can compete with each other for these values. Similarly, grid BESS can provide fuel savings for gas peaking plant whereas garage BESS can provide fuel savings for diesel generators on commercial and industrial sites.

Grid BESS can defer distribution augex but because the penetration of garage batteries remains low for all deployment pathways and electricity market scenarios, they are unable to provide any meaningful benefit in deferring distribution augex.

In terms of commercial returns, controlled garage BESS are able to provide consumer tariff reductions that are not directly realised by grid BESS.

Figure 7 Grid and garage BESS benefits



Finding 2: BESS on the low voltage network provide greatest system benefits

LV BESS provide the greatest overall system benefits, as shown by their location close to the top left corner of Figure 8. The analysis highlights that this difference in value is largely driven by the ability of LV BESS to defer distribution augex.

This system benefit does not directly align with the commercial benefit; MV BESS provide the greatest commercial value as shown in Figure 9. This is a possible cause of the limited investment in LV BESS in the NEM to date.

Finding 3: Controlled BESS creates value for the system and asset owners

Controlled garage BESS provide significantly greater system benefits and commercial returns than non-controlled garage BESS, as shown by their location further from the bottom right corner of Figure 8 and Figure 9.

Figure 8 Pathway costs and stacked system benefits (2019 $billions, real)

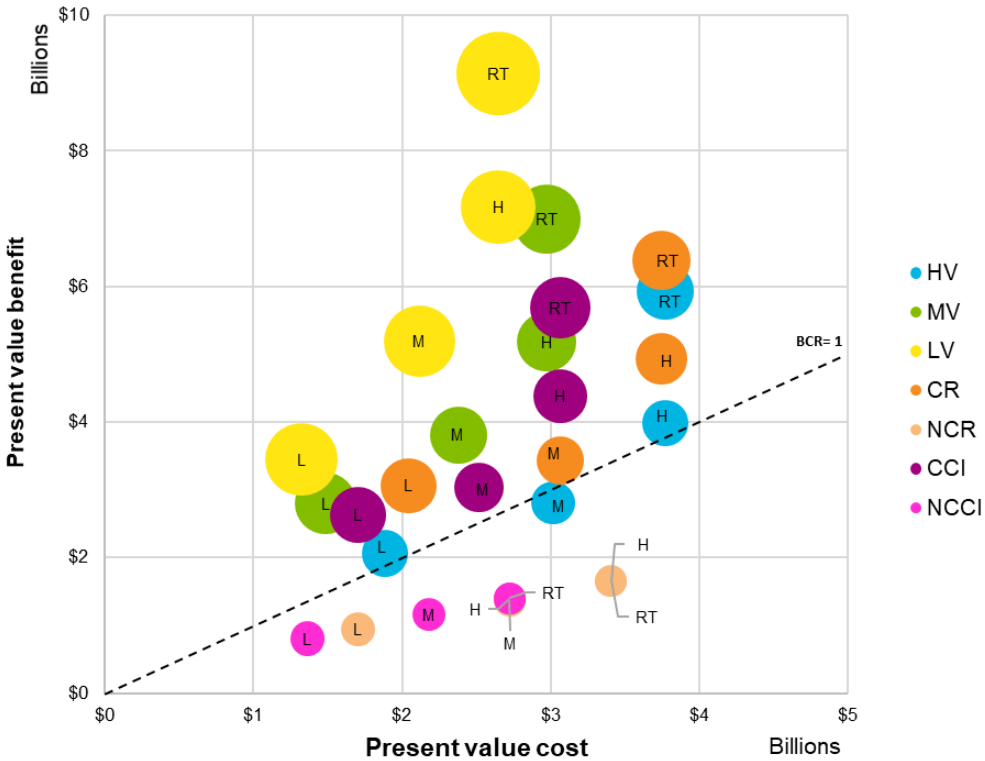
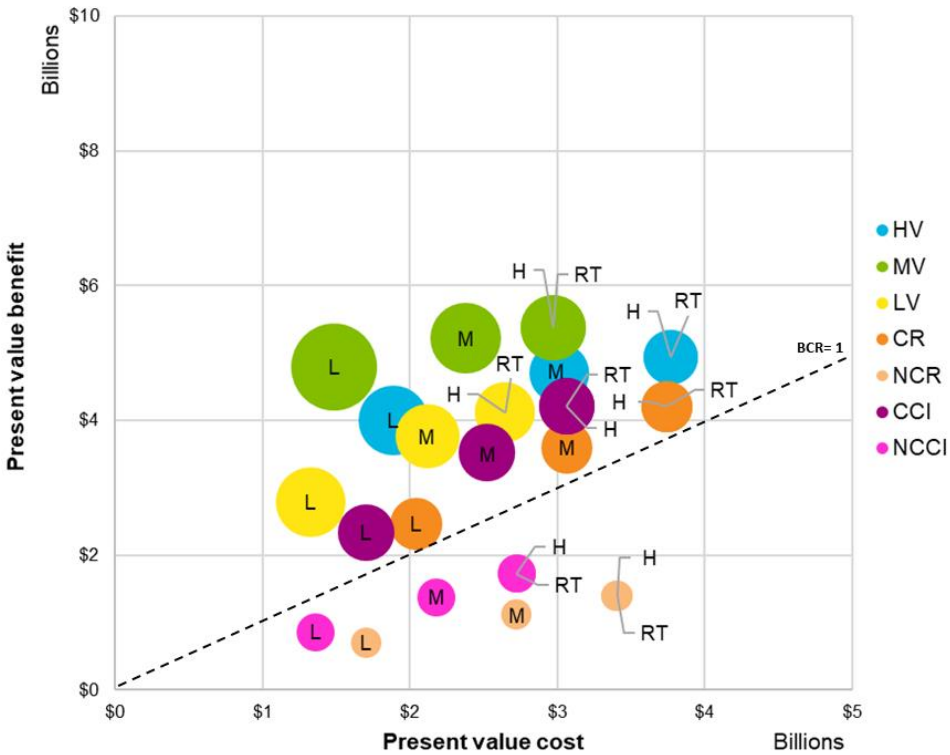


Figure 9 Pathway costs and commercial benefits (2019 $billions, real)



Implications

The deployment of BESS, especially when it starts to gather pace, raises important implications for policymakers, network owners, market bodies and asset owners, summarised in Table 1.

Table 1 Implications

Implication	Description
Optimising value for the network	While investors are likely to deliver a range of battery solutions into the market, outcomes may not necessarily be optimal from a whole of system perspective. There is merit in encouraging an appropriate balance of both utility-scale and smaller battery systems installed in the NEM to reflect the role which different scale BESS can play in the power system.
Reducing the uncertainty of investment	The extent that BESS, especially at utility scale, can provide system support services concerns the bankability of relevant ancillary service revenues. Addressing constraints on the ability of BESS projects to access finance on the right terms has the potential to encourage greater deployment of grid scale batteries.
Realising network performance	The analysis shows that utility scale BESS at LV level have the potential to significantly improve network performance. In order to realise the benefits, it will be necessary to test and resolve the technical limitations of BESS to improve network performance. For USE, this includes trialling the use of grid-forming inverters on radial networks and investigating the need to load match BESS to demand to reduce USE when islanded.
Promoting better system reliability and security	BESS deployment is an important complement to the growth of VRE and can support a reliable and secure NEM. Noting significant work undertaken in the frequency control frameworks review and identifying opportunities for fast frequency response in the NEM, there would be merit in testing the ability of deployed BESS to provide these and other ancillary services at scale.
Ensuring the value of behind the meter BESS are realised	There are likely to be issues if market arrangements regarding control mechanisms for residential and C&I BESS, which have the potential to deliver major commercial and system benefits, do not keep pace with technologies, or tariff arrangements aggravate electricity cost pressures for households without solar PV and BESS assets. It is important to note that consumers will invest in batteries behind the meter that provide a direct benefit to them, and as such there will be a component of CR or NCR in any real-world uptake pathway. This means that understanding the difference between these two configurations irrespective of their comparison to grid deployment pathways is crucial to informing the future benefit of behind the meter batteries.
Aligning tariff reform and social equity	Consumers that utilise behind the meter BESS to reduce their electricity costs will reduce overall revenues for network providers, particularly in the existing regulatory period. This revenue shortfall will be recovered through increased tariffs for consumers which will disproportionately affect consumers without distributed energy resources (DER), and it will be important to understand if retail offerings encourage BESS behaviour that increases costs for others in the long term. This issue needs to be managed by government and industry, especially in the context of structural changes in Australia's energy market and pressures on the rising cost of energy.

1.0 Introduction

Australia's electricity system is undergoing a profound evolution. It is shifting from a system based on a one-way distribution of power from large-scale thermal generators to a more decentralised structure in which energy comes from many smaller generators. These generators range in scale from wind and solar farms to residential installations, from which power may flow back into the grid. These distributed energy resources (DER) which produce electricity or actively manage consumer demand include solar photovoltaics (PV), batteries and electric vehicles (EV), as well as demand-responsive appliances such as hot water systems and pool pumps.

Importantly, these DER technologies are being connected to the power grid in a way that was not envisaged when the system was designed. Australia now has more rooftop solar PV installed per capita than any other country, and further growth is expected [1]. Moreover, battery energy storage systems (BESS) at the distribution level are emerging as a technology which can support increased penetration of intermittent generation, such as wind and solar PV. The installation of BESS at scale presents significant opportunities through its potential to manage load peaks and support frequency, voltage and system strength; however, it also presents a range of challenges across the system.

In this context, AECOM Australia Pty Ltd (AECOM) has been engaged by the Australian Renewable Energy Agency (ARENA) to examine the relative technical and economic merits of a suite of deployment pathways for low voltage (LV) grid-side and customer-side BESS deployments against utility scale high voltage (HV) and medium voltage (MV) BESS, under various electricity market scenarios. The assessment highlights how the scale, timing and distribution of BESS deployments influences the potential benefits to the network and to owners of the BESS assets, whether households or commercial entities. The analysis aims to support ARENA in its considerations about investing in BESS projects.

1.1 The role of batteries in energy storage

The large-scale deployment of energy storage has the potential to significantly alter electricity markets. Affordable energy storage is often seen as essential to integrate high penetration intermittent renewable generation, such as solar PV and wind, and ensure a secure and reliable network.

Crucially, storage can provide important services to the electricity system:

- Short-term energy storage can stabilise the grid by providing a rapid response capacity if there is an unexpected surge in demand or loss of supply.
- Daily energy storage can smooth generation requirements across the day, better matching the demand daytime peaks, shoulder periods and night-time troughs. This is seen with solar PV generation; the demand for energy is often higher in the evening after solar PV generation has fallen for the day.
- Intra-seasonal energy storage may be required to smooth variations in intermittent generation if output declines for several days at a time. This can occur, for instance, if weather events produce major cloud cover or long-lasting drops in wind speed. Battery technologies do not currently have sufficient capacity for this form of system balancing.
- Inter-seasonal energy storage would involve storing energy across seasons to capture surpluses when seasonal conditions for renewable generation are favourable and releasing it at other times of the year. Again, there are no current battery technologies that could provide such long duration services economically. Pumped hydro energy storage is the currently provider of this type of energy storage in the network and is not expected to be displaced by BESS.

The storage capacity of batteries in the National Electricity Market (NEM) is currently insignificant. Indeed, the primary purpose of almost all current BESS is to provide self-generation for households or specific facilities, or, where they are grid-connected, to provide stability on the local grid to support intermittent generation. The Clean Energy Regulator (CER) maintains a voluntary battery register, which currently indicates that there are almost 18,000 behind the meter battery installations, which represents about 2% of households [2]. There are currently five grid connected BESS registered on

the NEM, with a total registered capacity of 115MW compared to 5,364MW of installed hydro [3]. These BESS are all connected to the MV and HV networks.

In terms of battery technologies, lithium-ion (Li-ion) batteries typically receive the most attention and have progressed furthest in terms of their development. They are currently the most prospective battery technology over the next few decades. Different battery technologies have different costs and benefits, and as such this study does not apply to other battery technologies.

This study focuses on the relative costs and benefits of BESS deployment at different system levels, with a focus on LV network and behind the meter deployments. It does not compare these storage options against other alternative technologies which may provide a similar range of energy market outcomes. Rather, this study concentrates on the potential value of BESS, in the context of the Australian market, with a focus on:

- examining the relative technical and economic merits of widespread LV BESS deployment in front of and behind the meter
- how LV BESS deployment might be affected under current and future cost scenarios
- identifying where barriers and constraints to realising value from BESS deployment exist.

The study does not assess regulatory constraints and current tariff structures limitations.

1.2 Report structure

This report is structured in the following sections.

Section 2.0 provides a brief review of BESS, including how they work and the major differences between utility scale in front of meter and smaller behind the meter BESS, and how they connect with the network. An overview of the network services that BESS provide to electricity networks and electricity customers is also provided. This is drawn out in the form of a value map across different BESS deployment options.

Estimates for whole-of-life BESS costs are set out in section 3.0. As an emerging technology, costs are changing. The section highlights potential advancements in battery technologies and how costs may change going forward.

Section 4.0 discusses the suite of BESS deployment and electricity market scenarios which are assessed. Deployment options for both grid-side and customer-side BESS deployments over the next two decades are examined. These are overlaid on various electricity market environments, covering a spectrum of population growth, demand growth and dispatchable/renewable generation settings.

A technical assessment of BESS is provided in section 5.0. The analysis focuses on what system value or commercial return could be provided through different BESS services. This includes the potential for reduced network investments, fuel savings and ancillary service costs, as well as how higher levels of intermittent generation across the network would be supported. Estimates of the scale and quantum of technical value streams for specific BESS deployment pathways are detailed.

Section 6.0 examines the ability of BESS to provide these values simultaneously and provides a possible value stack for the economic assessment.

An economic assessment of BESS deployments, which builds on the technical evaluation, is provided in section 7.0. A socio cost benefit framework is applied which accounts for the whole-of-life costs of installed BESS and the specific benefits to the network and asset owners which are likely to accrue.

Finally, section 8.0 discusses the major policy implications related to different grid-side and customer-side BESS uptakes. Some specific recommendations for policy action are presented with a focus on addressing barriers to BESS deployment and maximising the technical and economic value which could be realised by supporting new BESS options.

A range of supporting information on technical assumptions, the battery cost review, the approach of the analysis, detailed results, and references are provided in the appendices.

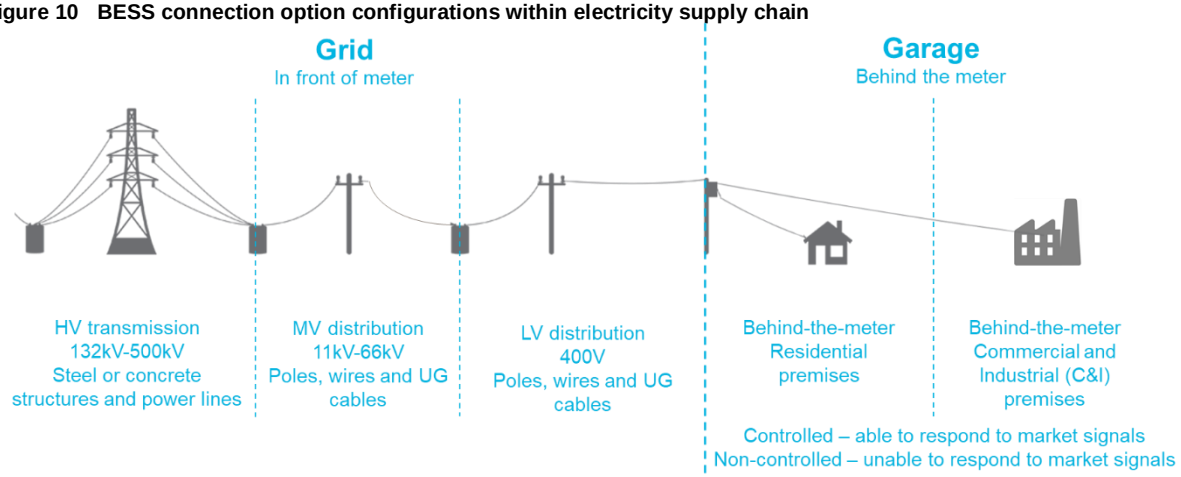
2.0 BESS services

BESS offer a range of possible services to electricity networks and electricity consumers. This section considers the BESS connection points, the services that BESS can offer to the electricity networks and consumers and the specific services that can be provided by the BESS configurations.

2.1 Connection points

BESS can be connected at different points within the electricity supply chain, as shown in Figure 10. Few BESS projects have been commissioned or are in development around Australia. Utility-scale HV BESS have gained public attention, with notable systems now operating in Hornsdale, Gannawarra, Ballarat and Dalrymple, some of which have received funding from state governments and ARENA [4] [5] [6] [7]. There are limited BESS currently connected to the MV and LV networks. Behind the meter BESS installations are becoming increasingly popular for commercial and industrial (C&I) and residential customers. These customers may install BESS as part of a virtual power plant (VPP), usually operated by an energy retailer, or as a standalone system for energy storage.

Figure 10 BESS connection option configurations within electricity supply chain



This study considers BESS configurations connected across all five connection points, with two additional options for behind the meter BESS that are controlled and non-controlled BESS, where controlled can respond to market signals:

1. HV network
2. MV network
3. LV network
4. Controlled residential (CR)
5. Non-controlled residential (NCR)
6. Controlled C&I (CCI)
7. Non-controlled C&I (NCCI)

The typical system characteristics for each BESS configuration have been estimated using existing Australian BESS projects, summarised in Table 2. Further detail is provided in Appendix A.

Table 2 BESS typical system characteristics

Characteristic	HV	MV	LV	CR	NCR	CCI	NCCI
Rated output (kW)	25,000	1,000	50	5	5	100	100
Capacity (kWh)	37,500	1,000	125	12.5	12.5	300	300
Dispatch time (hrs)	1.5	1	2.5	2.5	2.5	3	3

2.2 Services provided

BESS can provide a wide range of services that yield technical, commercial and economic value for both the electricity networks and the electricity consumers in Australia. They can be categorised into five high level functions as shown in Figure 11. These services are described in Table 3, which also identifies which BESS connection options can provide the associated service.

Figure 11 High-level battery services

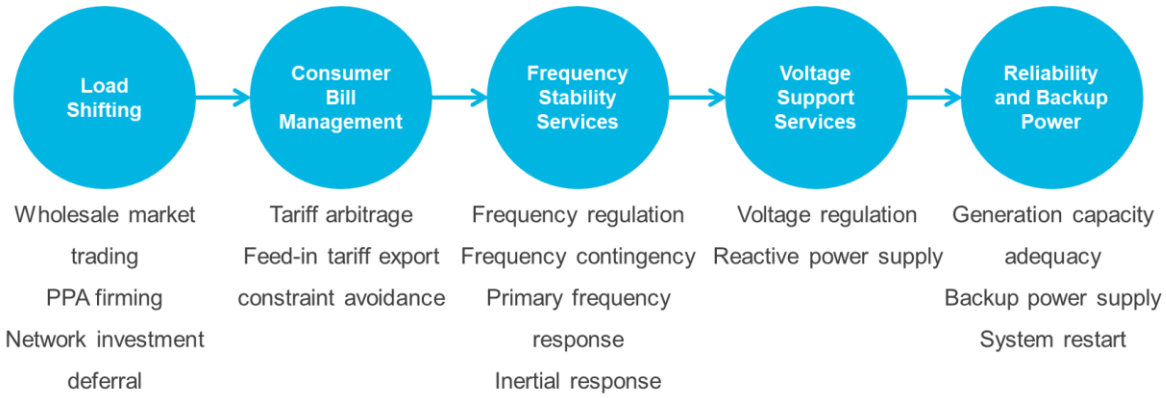


Table 3 BESS services descriptions and markets

Service	Description	Market	HV	MV	LV	CR	NCR	CCI	NCCI
Load shifting									
Wholesale market trading	Shift electricity from periods of low market value to periods of high market value	Wholesale market	✓	✓	✓	✓	×	✓	×
Power purchase agreement (PPA) firming	Increase the value of PPAs by increasing the dispatchability of the contracted power to be bought/sold	PPA	✓	✓	✓	•	×	•	×
Network investment deferral	Reduce investment into additional transmission and distribution (T&D) network upgrades to meet peak demand	-	•	•	•	•	×	•	×
Consumer bill management									
Tariff arbitrage	Reduce consumer tariffs by reducing consumer consumption during peak tariff bands, consumer peak demand and overall energy consumption from the grid	Retail	×	×	×	✓	✓	✓	✓
Feed-in tariff export constraint avoidance	Store excess electrical energy that can't be exported to the grid, and sell later when the export constraint is lifted	Feed-in tariff	×	×	×	✓	✓	✓	✓
Frequency stability services									
Frequency regulation	Manage network frequency by increasing or decreasing power supply to meet demand in the Frequency Control and Ancillary Services (FCAS) market	FCAS regulation	✓	✓	✓	•	×	•	×

Service	Description	Market	HV	MV	LV	CR	NCR	CCI	NCCI
Frequency contingency	Provide reserve for frequency control in response to contingency events	FCAS contingency	✓	✓	✓	•	×	•	×
Primary frequency response	Provide active power to quickly respond to measured changes in local frequency	-	•	•	•	•	×	•	×
Inertial response	Provide 'artificial inertia', slowing the ROCOF	-	•	•	•	•	×	•	×
Voltage support services									
Voltage regulation	Manage network voltages by providing or reducing active power to counter voltage deviations	NSCAS tender process	•	•	•	•	×	•	×
Reactive power support	Manage network voltages by supplying or absorbing reactive power	NSCAS tender process	•	•	•	•	×	•	×
Reliability and backup power									
Generation capacity adequacy	Provide additional dispatchable capacity to utility-scale generators or additional dispatchable capacity to distributed PV resources by storing unused generation	-	•	•	•	•	•	•	•
Backup power supply	Provide backup power to the network during periods of network outages or to localised areas during periods of localised power outages or to behind the meter premises	-	•	•	•	•	•	•	•
System Restart	Provide additional power to help generators restart following a blackout	SRAS tender process	✓	•	×	×	×	×	×

✓ Service able to access existing market
• Service able to be technically provided but without access to an existing market
× Service unable to be provided

2.3 Value of BESS services

The services provided by BESS can each provide a unique value offering to the electricity system through a combination of cost savings, increased market competition, and increased asset utilisation. Our analysis identifies thirteen unique value streams which represent the system or investors' commercial benefit which can be achieved through the provision of the combined BESS services. Ultimately, each of the system benefit value streams lead to a net benefit for all electricity market participants, from customer to market regulator [8]. The commercial benefit value streams are direct benefits to the asset owner or operator; they are less likely to be value creation for the system and more likely to represent wealth transfer to the asset operator. The mapping of services to their corresponding values is shown in

Figure 12, where the services are on the left side of the figure. Each battery service can provide several market benefits. The derivation of the value of each stream, and discussion around the associated limitations, are described in detail in section 5.0.

Figure 12 Value-adding services

Services		System benefits										Commercial benefits			
		Base generator capex/ opex avoidance and deferral	Peaking plant capex/ opex avoidance and deferral	Transmission and distribution capex/ opex avoidance and deferral	Fuel savings for dispatchable generators	Maximising intermittent generator utilisation	Reduced T&D power losses	Reduced USE	Reduced NSCAS	Reduced FCAS	Reduced SRAS	Wholesale revenue	PPA firming	Consumer tariff reduction	FCAS revenue
Load shifting	Wholesale market trading					✓						✓	✓		
	PPA firming					✓						✓	✓		
	Network investment deferral		✓	✓	✓		✓	✓	✓	✓		✓		✓	✓
Consumer bill mgt	Tariff arbitrage				✓	✓								✓	
	Feed-in tariff export constraint avoidance				✓	✓								✓	
Frequency stability	Frequency regulation		✓		✓			✓		✓	✓				✓
	Frequency contingency		✓		✓			✓		✓	✓				✓
	Primary frequency response							✓		✓	✓				✓
	Inertial response							✓		✓	✓				✓
Voltage support	Voltage regulation		✓		✓		✓		✓						
	Reactive power support								✓						
Reliability and backup power	Generation capacity adequacy	✓	✓	✓	✓	✓	✓					✓	✓	✓	
	Backup power supply		✓		✓			✓							
	System Restart Ancillary Services		✓		✓						✓				

3.0 BESS technology and expenditure

While the outlook [9] is that batteries will become more energy dense and less costly over time, the total cost of a BESS involves number of other components that do not expect to reduce in cost over time. Because of these broader system hardware costs, as well as the cost of siting, installation and maintenance, it is important to consider the whole-of-project costs of a BESS. This section considers:

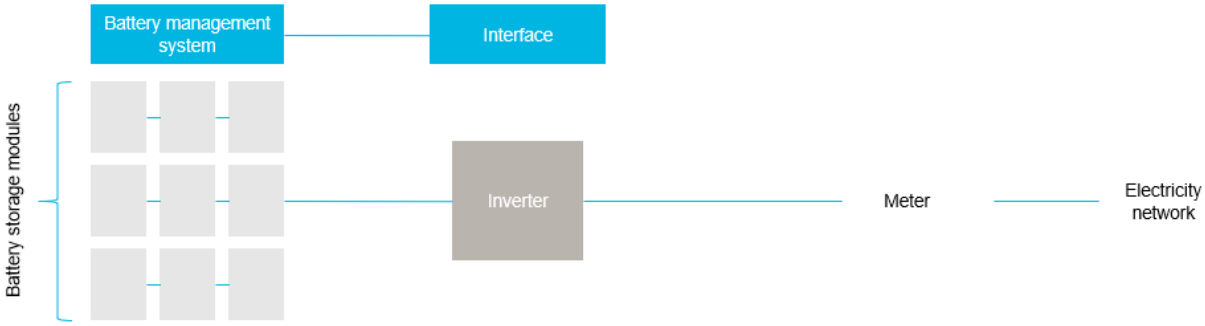
- The components that make up a BESS
- Battery technologies
- The expenditure associated with Li-ion BESS.

3.1 BESS system components

A BESS, whether at residential or utility scale, involves a package of battery modules, electronics, and software to manage the charge and discharge cycling, the depth of discharge and a range of other battery management functions.

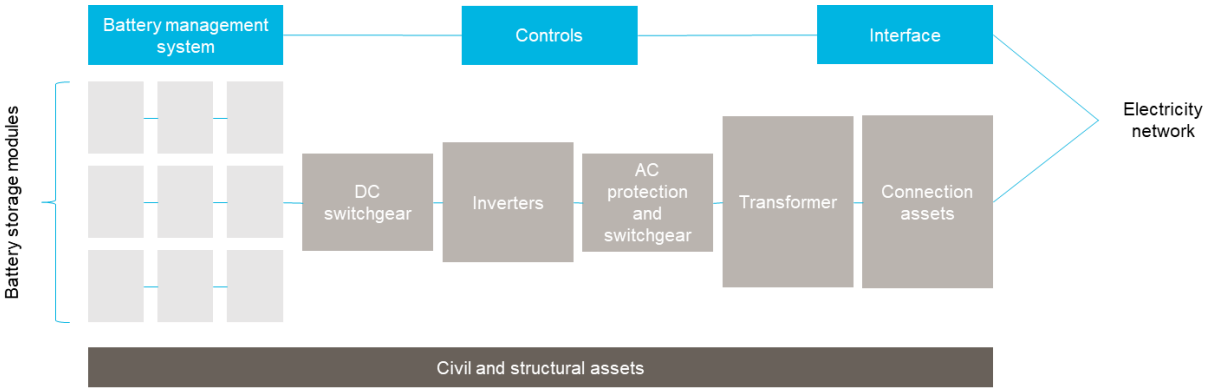
The behind the meter (CR, NCR, CCI and NCCI) BESS configurations will include capital expenditure (capex) for these components (see Figure 13) as well as installation costs [10]. Additional land is not needed as units are retrofitted into existing residential premises.

Figure 13 Behind-the-meter BESS components



Grid (HV, MV and LV) BESS configurations will have these capex costs as well as costs associated with system studies, connection assets, civil infrastructure such as roads and fencing, outage management, secondary systems and additional establishment, financial and administrative costs, as shown in Figure 14.

Figure 14 In front-of-meter BESS components



3.2 Battery technologies

There are a variety of battery technologies with differing applications. Li-ion is the most promising BESS battery technology and currently dominates investment in new energy storage, both at the residential and utility level. The analysis in this report is based on Li-ion BESS.

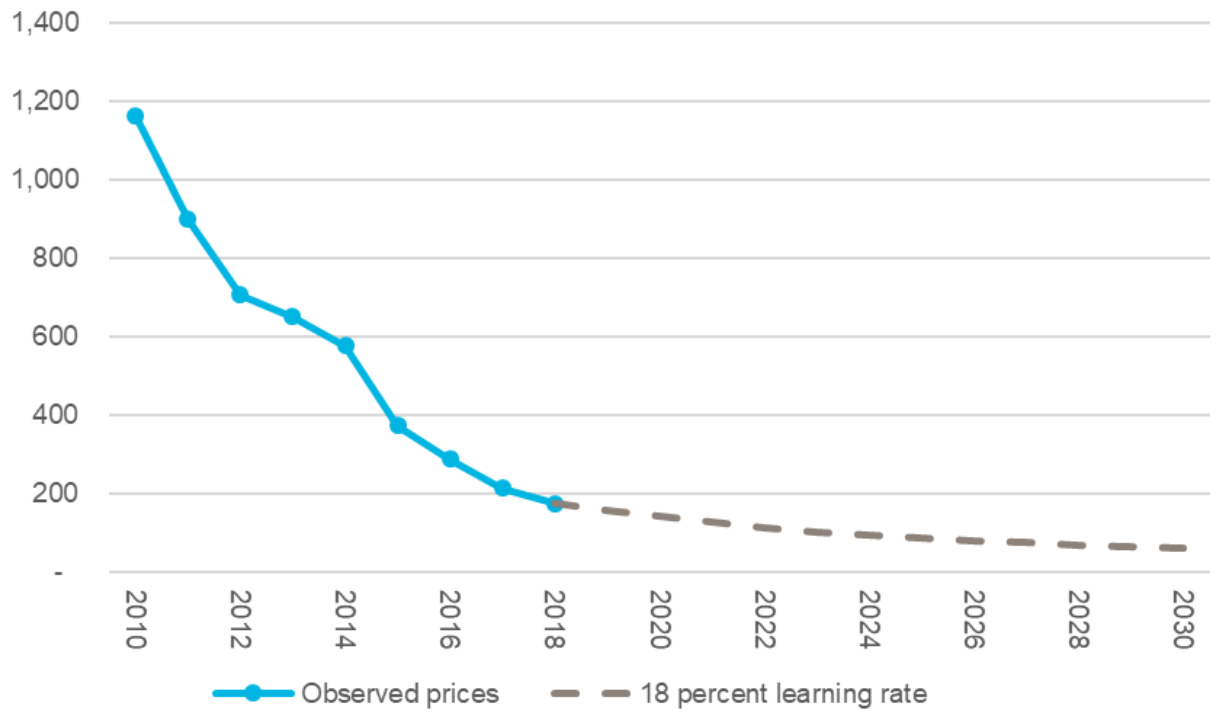
There are several reasons why Li-ion battery technologies have strong commercial deployment expectations:

- multiple chemistries and lithium compounds are available with potential for ongoing improvements across both energy and power applications
- they have good performance characteristics including relatively high energy density, low self-discharge and high charging efficiency
- there is a rapidly expanding global manufacturing base and extensive supply chain availability which can drive economies of scale and commensurate reductions in battery cell and system costs, a process that will likely be accelerated by further electrification of the transport industry.

Analysis has highlighted a consistent downward trend in the prices for Li-ion batteries since 2010, as shown in Figure 15. Over the period between 2010 and 2018, the price of Li-ion batteries fell by close to 85%. While there are strong reasons to indicate that the cost of li-ion batteries will continue to fall, the magnitude of any cost reduction over the longer term is difficult to predict, as it is with many rapidly emerging technologies.

Bloomberg New Energy Finance (BNEF) assessment suggests that Li-ion battery price reductions over the next decade may moderate as some of the earlier technological and 'learning by doing' improvements in production and in-country installation practices are locked in and the technology itself matures. This is a cost curve typical of many forms of high-tech componentry as they develop and become widely adopted.

Figure 15 Li-ion battery prices (US$/kWh, real 2018) [9]



3.3 BESS expenditure

For each BESS configuration the asset life, capex and opex, summarised in Table 4, have been calculated using information drawn from a range of existing and planned BESS projects across Australia, detailed in Appendix A. The resulting expenditure has been cross-checked against BESS costing studies [11] [12] [13] [14]. There is a cost borne by distribution network service providers (DNSP) to enable controlled BESS operation within their networks for CR and CCI BESS [15]. South Australia Power Networks (SAPN) is currently experiencing the need to manage their LV networks to address the uptake of DER. It is likely that other DNSPs will experience the same issues relatively soon after. As such, the SAPN LV management cost outlined in their 2020 to 2025 determination, has been applied in the near term. An extrapolation of this cost has been applied to the rest of the DNSPs in the NEM, based on the energy supplied by the DNSPs, and distributed over the following five-year period.

With battery costs, which comprise between 70 and 89% of total BESS capex, expected to decline in the future, as outlined in section 3.2, the capex for each BESS configuration is also likely to reduce over the medium to long term [16]. The battery proportion of the BESS capex, outlined in section 3.1, has been reduced over time by the expected battery learning rate of 18%.

Capex weighted by capacity is higher for behind the meter residential BESS where economies of scale are unlikely to be achieved. Capex is higher for HV and MV network connections which tend to involve significant connection activities and land acquisition. The higher costs for HV BESS are reflective of the battery size chosen. The costs associated with system studies, connection assets, civil infrastructure outage management, secondary systems and additional establishment, financial and administrative costs, would be diluted if a larger battery was chosen.

Opex costs are higher for BESS connected to the networks where maintaining the performance of the system is critical to the financial viability of the project. As battery systems move from HV to behind the meter (HV→NCCI), opex and asset life decreases.

Table 4 2019 BESS expenditure (2019$, real)

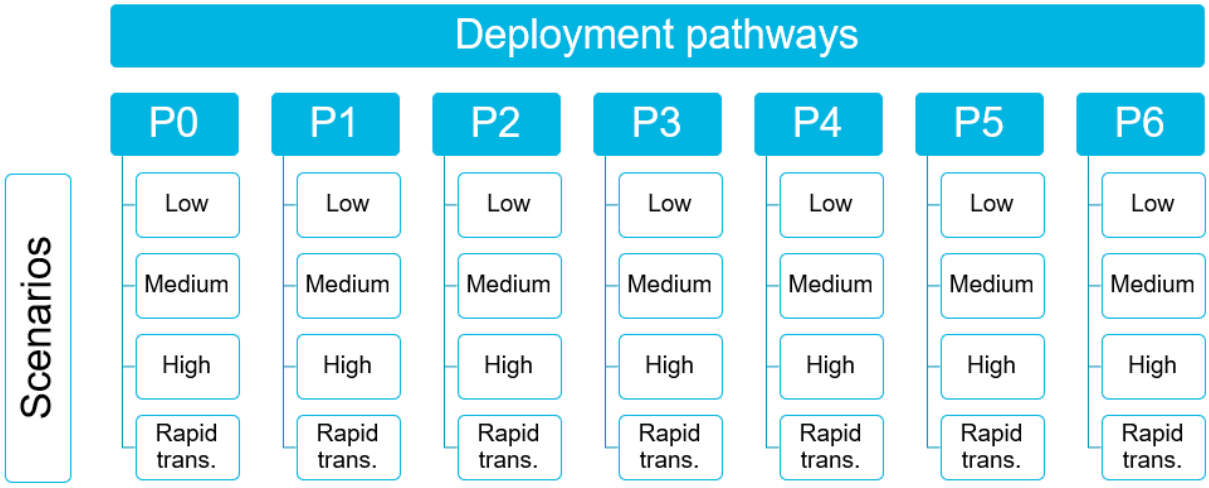
Item	HV	MV	LV	CR	NCR	CCI	NCCI
Typical rated output (kW)	25,000	1,000	50	5	5	100	100
Typical capacity (kWh)	37,500	1,000	125	12.5	12.5	300	300
Asset life (years)	17.8	13.3	14.4	12.5	12.5	12.5	12.5
Capex ($/kWh)	1,077	1,029	915	1,254	1,254	947	947
Battery proportion of capex (%)	69.5	79.2	81.5	83.8	83.8	83.8	83.8
Opex ($/kWh p.a.)	18.64	16.56	16.56	7.04	7.04	8.80	8.80
2020-25 LV network mgt ($M)	-	-	-	32	-	32	-
2025-30 LV network mgt ($M)	-	-	-	446	-	446	-

We note there is limited cost data for BESS which creates significant uncertainty on the cost estimates, especially given the limited uptake of LV BESS to date. It is likely that new project cost data will become available which could alter these cost estimates going forward and impact on the analysis within the report.

4.0 BESS deployment pathways and scenarios

This report defines seven different pathways to deployment of BESS. These pathways are tested across four scenarios to present a range of potential outcomes for alternative future states of the world. The scenarios, that recognise inherent uncertainties about how electricity markets might change over the coming decades, represent alternative future states of the world. A summary of the deployment pathways and scenarios is shown in Figure 16, and is discussed further below.

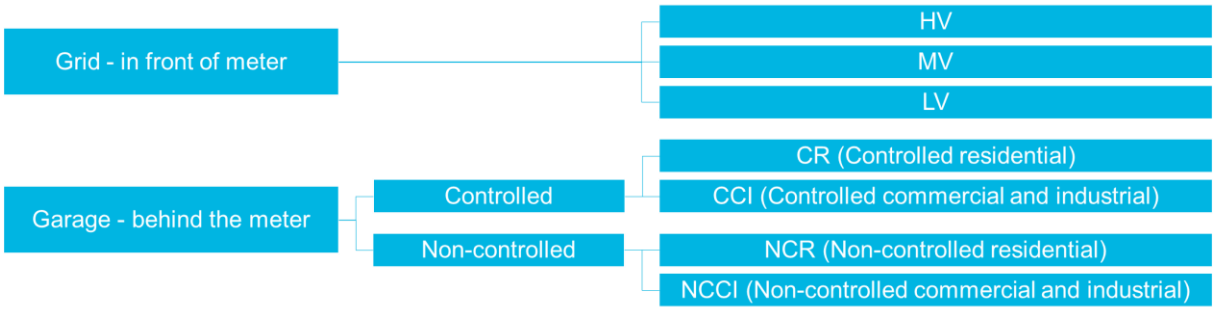
Figure 16 Deployment pathways vs scenarios



4.1 Deployment pathways

This study considers seven different BESS deployment pathways, each containing only BESS connected at a particular point in the supply chain, as shown in Figure 17.

Figure 17 BESS deployment pathways



Further deployment options that consider a mix of connection types may be investigated following this study.

To compare these deployment pathways, an equivalent battery system capacity (37.5MWh) has been defined, and the number of units required for each deployment pathway calculated based on the typical system sizes of the associated BESS, as shown in Table 5.

Table 5 Deployment pathways - typical system characteristics

Characteristic	HV	MV	LV	CR	NCR	CCI	NCCI
Rated output (kW)	25,000	1,000	50	5	5	100	100
Capacity (kWh)	37,500	1,000	125	12.5	12.5	300	300
No. BESS in a unit	1	38	300	3,000	3,000	125	125
Total capacity per unit (MWh)	37.5	37.5	37.5	37.5	37.5	37.5	37.5

Battery storage costs across the deployment pathways are detailed in section 3.3.

4.2 Scenarios

This study considers four distinct scenarios, shown in Table 6, that recognise inherent uncertainties about how electricity markets might change over the coming decades, and thus represent alternative future states of the world.

Table 6 Scenario details

Scenario	Low	Medium	High	Rapid trans.
Source	ISP Slow	ISP Neutral	ISP Fast	BNEF NEO
Economic growth	Weak	Neutral	Strong	Neutral
Population outlook	Weak	Neutral	Strong	Neutral
Emissions reduction trajectories 2005-2030	28%	28%	52%	42%
Demand side participation	Strong	Neutral	Weak	Strong
EV uptake	Weak	Neutral	Strong	Strong
Battery storage aggregation by 2050[11]	90%	50%	10%	90%
Energy efficiency improvement	Weak	Neutral	Strong	Strong
Variable renewable energy (VRE) cost reductions	Slow	Neutral	Neutral	Rapid
Storage cost reductions	Neutral	Neutral	Rapid	Rapid
Gas demand and export	Weak	Neutral	Strong	Neutral
Gas prices	Neutral	Weak	Strong	Neutral

The scenarios have been designed to align with the view of network planners, predominantly the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) 2019, to span a range of plausible grid consumption and supply outcomes.

[1] Battery storage aggregation is the proportion of BESS that are controlled vs non-controlled.

The scenarios were developed around different energy market conditions:

- variations in grid demand
- variations in economic and population growth, levels of consumer demand side participation, and the deployment of new technologies, such as EV
- variations in gas prices and emissions reductions settings.

Across these areas, the low, medium and high scenarios essentially involve moving towards an environment featuring changing electricity demand, greater penetration of EV, and more energy efficiency improvements. All scenarios involve a growing penetration of DER, consistent with observed trends in which residential, industrial, and commercial consumers are investing strongly in rooftop solar PV and there is keen interest in battery storage and load management. In effect, energy markets become more transformational as the scenarios move from low to high.

A fourth 'rapid transformation' scenario examines battery deployments within an alternative energy system characterised by an even more substantial change in sources of electricity generation. This scenario, based on options presented in the BNEF New Energy Outlook 2019, involves immediate and profound changes to consumption, demand management and technology adoption [16]. Energy markets evolve quickly with all key drivers undergoing a rapid rate of change over the next 20 years.

Detailed scenario parameters are set out in Appendix B.

4.2.1 Low scenario

In the low scenario, annual electricity demand is forecast to decrease between FY2019 and FY2038 in terms of peak demand (-0.6% per year) and total consumption (1.6% per year). Lower numbers of batteries are deployed as a result. Capex and opex are lowest in this scenario as a result, as are the benefits able to be realised through the deployment of batteries [17].

4.2.2 Medium scenario

In this scenario, FY2038 electricity consumption is forecast to be approximately 50% higher than in the low scenario, with a greater proportion from renewable sources. The increased consumption drives greater deployment of storage batteries, with approximately 50% more batteries installed by FY2038. This increases the total costs of each pathway compared to the low scenario, but also increases the benefits generated [17].

4.2.3 High scenario

The high scenario assumes stronger growth than the low and medium scenarios in terms of total electricity consumption and peak demand. By FY2038, electricity consumption is 13% higher than under the medium scenario, and 70% higher than under the low scenario. This results in greater deployment of storage batteries relative to the low and medium scenarios, increasing pathway costs and benefits [17].

4.2.4 Rapid transformation scenario

This scenario applies electricity consumption and peak demand forecasts adapted from the BNEF New Energy Outlook 2019. By FY2038, peak demand and total electricity consumption are forecast to be 12% and 37% higher than the high scenario, respectively. More than three quarters of total electricity generation is from renewable sources, increasing from one third in FY2019. A total of 33GW of generation capacity is assumed to be retired by FY2038, more than double that of the high scenario [16].

5.0 BESS technical assessment

The value derived from each BESS reflects its location in the network and the scenario under which it is operating. For example, a BESS that is located at a customer premise may be able to provide power to that premise when a local network element is out of service, whereas a battery located at transmission level cannot. Similarly, only a BESS located below a constrained element can substitute for augmentation on that element.

This section describes the methodology to quantify the identified value streams of BESS under each scenario to 2038/39. We have used a range of sources to make an informed estimate of the potential benefit or offset cost that each deployment pathway can provide through its services. Supporting annual results are provided in Appendix C, which are individually referenced in each value stream section.

5.1 Base generation capex/opex avoidance and deferral

Electricity consumption in Australia is forecast to grow in most scenarios, reflecting the increasing demand for electricity driven by population growth and electrification of transport and other industries, despite behind the meter solar PV installations plateauing [18] [19]. Pairing this with the planned retirement of existing coal-fired generators, there is a current and future need to develop new base generation plant. This market gap is being filled by new solar PV and wind farm development, with nearly 25 GW of solar PV and 17 GW of wind farms currently at various stages of project development and in the proposal stage with AEMO [20] [21].

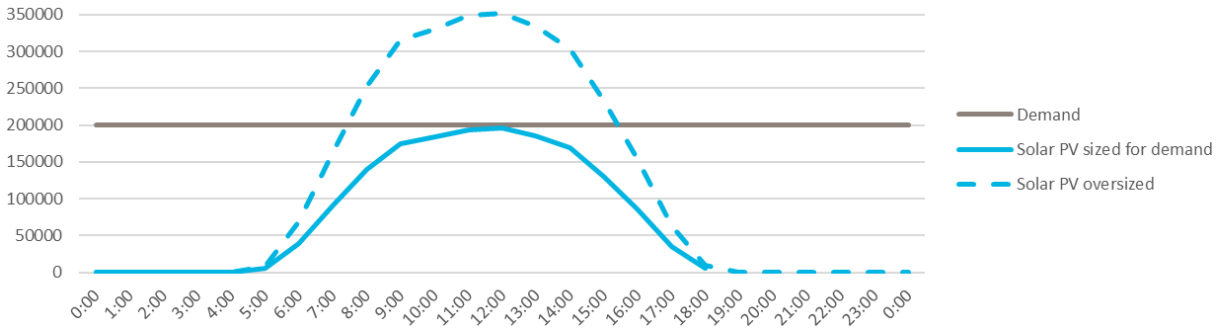
One challenge associated with an increased reliance on renewable generation is the intermittent nature of the electricity supply. Matching generation with demand is the main function of AEMO and is made challenging because solar PV only generates electricity during daylight hours and wind generation is a function of wind speed. Demand for electricity changes throughout the day, but not at the scale or frequency of the change in supply. BESS can be used to manage this difference between electricity supply and demand by shifting excess generation to meet demand later. This profile matching process reduces the need to install new solar PV and wind generators to meet the increasing base demand.

Note that for the purposes of this study, we have assumed that intermittent renewables will be over installed in the absence of BESS in order to maximise the amount of generation provided to the network. We are assuming no new thermal generation will be installed to meet future base generation and have assumed the uptake of gas generation will only be for peaking, as outlined in the ISP. As such, gas generation avoidance and deferral is addressed in peaking plant, section 5.2 and fuel savings for dispatchable generators, section 5.4.

In all scenarios, the increase in energy generation is being provided by renewable energy, predominantly solar PV. Solar PV has a daily profile because generation occurs only during daylight hours. The amount of energy that can be provided in the early hours of the day and late afternoon can be increased by oversizing systems and increasing the number of installations (as shown in Figure 18) but the hours of the day that solar PV can generate are fixed. The installation of BESS can utilise excess solar generated by an oversized system and deliver energy outside of daylight hours, see maximising intermittent generator utilisation in section 5.5. As the number of BESS installations increases, the amount of solar and wind that needs to be built to meet base generation needs reduces.

We compare the typical daily generation profile of wind and solar PV generators with the increasing daily demand profile to determine how much new base generation will be required to meet the changing demand profile. With BESS deployment, the amount of solar PV and wind generation installed will reduce as excess generation is shifted to meet periods of high demand that would have otherwise required additional base generation plant to meet. The analysis assumes that the average BESS charge is 50% and has a round-trip efficiency (RTE) of 92% [22].

Figure 18 Solar PV system sizing and ability to meet demand



An average of utility solar PV and wind levelised cost of energy (LCOE) has been used to represent the associated cost saving of the offset solar PV and wind generators (see Table 7). This price represents the costs to be recovered if the wind and solar PV were installed. The LCOE of wind and solar PV is updated regularly using real project values and can be found in several recent pricing studies, an average of which is shown in Table 7 [13] [23]. The estimated savings of offset new base generation in the medium scenario for 2019/20 is summarised in Table 7, with later years for each scenario shown in Table 53 in Appendix C.

Table 7 Base generation capex/opex avoidance and deferral value in medium scenario 2019/20 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Offset solar and wind generation LCOE ($/MWh)	60	60	60	60	-	60	-
Annual energy offset (MWh)	336,802	336,802	336,802	336,802	-	336,802	-

Levelised cost of energy

LCOE is one of the primary metrics for measuring the cost of electricity produced by a generator. It is calculated by accounting for all a generating plant's expected lifetime costs, which are then divided by the generator's lifetime expected power output (MWh). Future costs are discounted to net present value (NPV) terms. LCOE includes:

- land acquisition
- construction
- financing, taxes and insurance
- fuel
- maintenance
- overheads.

LCOE allows meaningful comparisons between renewables characterised by high capex low marginal costs (zero or low Variable Operations and Maintenance costs (VOM)) and traditional generators, which have comparatively low capital cost but high marginal costs (high VOM costs). Core components of VOM costs include incremental fuel, maintenance, labour and opex.

5.2 Peaking plant capex/opex avoidance and deferral

Peaking plant is used to generate electricity during periods of high consumer demand when there is insufficient base generation supply. As with base generation, BESS can be used to manage the peak demand seen on the network through load shifting, which reduces the need for additional peaking plant in the future.

Gas generation is a fast response peaking plant currently installed in the NEM and is anticipated to continue to provide peaking services for the foreseeable future. In the absence of significant BESS deployment, new installed peaking plant are also predominantly anticipated to be gas. For short term peaking, BESS can provide a fast response and displace the need for new gas capacity. This is particularly true where existing gas plant continue to provide peaking for longer periods of high demand. Potential system strength concerns may be raised by the direct replacement of peaking plant with BESS, which could limit the peaking plant offset in practice. In the case that grid-forming inverters are proven to provide synthetic inertia and fault current their uptake would eliminate this concern.

The ISP provides a forecast for the rated capacity of new peaking plant installations and associated peaking plant generation in each year to 2038/39 under each scenario of this study. The amount of gas peaking plant that can be offset is limited by the lower of the installed BESS capacity rated output and the rated output of the peaking plant installations in that year. The offset capacity is converted to an energy equivalent using a 20% gas peaker generation capacity factor [24], which is then valued using the peaking plant LCOE, applying an average BESS charge of 50% and an RTE of 92%. This value represents the costs to be recovered if the new gas peaking plant were installed.

The estimated savings of offset peaking plant generation in the rapid transformation scenario for 2019/20 is summarised in Table 8 below, with later years for each scenario shown in Table 56 in Appendix C.

Table 8 Peaking plant capex/opex avoidance and deferral value in rapid transformation scenario 2019/20 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Peaking plant LCOE ($/MWh)	210	210	210	-	-	-	-
Annual energy offset of new peaking plant (MWh)	78,428	78,428	78,428	-	-	-	-

5.3 T&D capex/opex avoidance and deferral

Transmission network service providers (TNSP) and distribution network service providers (DNSP) own and manage the network to deliver energy to customers. They monitor the demand and other limitations on feeders and substations to forward plan any augmentation work that is required to meet consumer demand and other network requirements. Strategically placed BESS can be used to defer or avoid augmentation of constrained up stream network elements.

5.3.1 Transmission capex/opex avoidance and deferral

AEMO's ISP provides the planned transmission upgrades to 2040 under each scenario of slow, neutral and fast transformation. It is assumed that the rapid transformation scenario will have the same transmission upgrades as the high scenario. We have considered BESS as a direct replacement for the transmission upgrades outlined in the ISP, when installed on the transmission network. The volume of replacements is limited by the installed rated output of the BESS deployment pathway in each year that an augmentation is proposed. Transmission upgrades are highly locational-based investments. This analysis assumes that BESS installed to reduce transmission upgrades are prioritised based on maximising the offset cost of upgrades over the reported time period and that thermal constraints occur for less than two hours at a time for the peaks each day.

Downstream BESS can impact transmission lines at a lower rate than those installed on the transmission network and as such a diversity factor commonly used in network planning has been applied to account for the likely coincident impacts on demand. This diversity factor [25], shown in

Table 9, represents the relationship between the coincident impact of the BESS operation throughout the supply chain; the lower the BESS connection along the electricity supply chain, the less the BESS can be a direct substitute for transmission upgrades. The intent of this approach is to ensure that the analysis does not overstate the impact of BESS not connected to the transmission network.

In an ideal world, controlled BESS would be orchestrated such that their impact would be coincident and they would be able to provide a 1:1 benefit; however controlled batteries are not centrally controlled by a single operator and have different drivers for utilisation.

The estimated savings of offset transmission capex in the low scenario for 2021/22 is summarised in Table 9 below, with later years for each scenario shown in Table 54 in Appendix C.

Table 9 Transmission capex/opex avoidance and deferral in low scenario 2021/22 ($, 2018)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Annual transmission capex deferred ($M,2018)	5	5	5	5	5	5	5
Diversity factor (%)	100	80	64	50	50	50	50

5.3.2 Distribution capex/opex avoidance and deferral

DNSPs augment their asset base to meet the maximum demand of consumers on their network. The main assets that are augmented are the substations and feeders that are used to transport electricity to consumers, which typically means increasing their carrying capacity to facilitate a greater amount of energy transfer capability.

BESS that are connected to the distribution network can be installed to provide the same services as distribution asset augmentation BESS connected to the distribution networks, MV and LV, can displace an equivalent amount of network augmentation, based on the installed rated output of the BESS. BESS can provide services to reduce the maximum demand seen by the distribution assets and would be installed in the locations in most need of network support. This analysis assumes that the majority of distribution upgrades occur to meet increasing peak demand, but that feeders are not highly utilised at other times of the day.

The location of the BESS connection in relation to the electricity network determines which DNSP assets it can impact. MV, which is connected to the MV network, can defer augmentation to sub-transmission feeders and sub-transmission substations, as these are located upstream of the MV-connected BESS. Additionally, we have assumed that on average half of the zone substations are located upstream of MV BESS, meaning that half of the augmentation expected for zone substations can be deferred by MV. Similarly, LV, which is connected to the LV-network, can offset augmentation to sub-transmission assets, as well as all zone substations and half of the distribution HV feeders.

BESS connected behind the meter have a limited impact on distribution augmentation because the penetration levels of BESS are too low. The planned augmentation of distribution assets are significantly more numerous than the BESS installed, and the maximum demand growth on the distribution network exceeds the garage BESS penetration rates in all scenarios. It is possible that garage BESS could offset some distribution augex if small local areas have high penetration and can impact the network characteristics driving augmentation in the local area.

An estimate of augmentation rates was developed based on the published RIN augex forecast for five years. We applied the published growth rate for each feeder to determine the expected maximum demand in each year to 2038/39, with some adjustment to account for recently created feeders with low loading and high growth rates. Augmentation is required when the maximum demand on a feeder in a given year is greater than the feeder rating. Distribution assets have long lives of 40 – 100 years, which means it is unlikely that DNSPs will undertake piecemeal small augmentations to feeders or substations; the analysis assumes that the augmentation required will upgrade the feeder to meet the feeder demand in 2039/40. The capex unit rates are based on 5-year average of actual and forecast expenditure in the published RINs.

The estimated augex savings for DNSPs in the low scenario for 2018/19 is summarised in Table 10 below, with later years for each scenario shown in Table 55 in Appendix C.

Table 10 Distribution capex/opex avoidance and deferral in low scenario 2018/19 ($M, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Annual augex deferred	-	16.3	45.9	-	-	-	-

5.4 Fuel savings for dispatchable generators

The predominant fuel types for dispatchable generators are gas and diesel; gas is typically used for utility scale peaking and diesel is typically used for backup generation for C&I customers. BESS can be used in place of dispatchable generators, reducing the cost of the diesel and gas inputs. For this application BESS will require the technical capability to operate in back-up or islanded mode, which we anticipate being commonly deployed in the coming years.

For gas peaker generation, the amount of fuel savings possible is limited by the BESS rated output. In all scenarios the rated capacity of installed peaking generation is higher than the BESS rated output. As such, we have assumed that BESS will be utilised for all short duration peaking, and the longer duration peaking will continue to be provided by gas. The forecast gas peaker rated output and forecast generation is provided in the ISP to 2038/39, which we assume can be directly offset by an equivalent capacity of BESS in front of the meter assuming an average BESS charge of 50% and round-trip efficiency (RTE) of 92%. Gas prices are forecast in AEMO's ISP [17].

For diesel generators, the average time that C&I customers experience unserved energy (USE) events is calculated by applying the average interruption duration to the average interruption frequency for C&I customers. The BESS dispatch time for C&I pathways is equivalent to the average interruption duration experienced by C&I customers. As such, the reduced diesel energy has been calculated by applying the annual interruption time to the BESS rated output. Diesel prices are taken as the national average for the past 12 months [26].

The estimated savings of offset fuel savings in the low scenario for 2018/19 is summarised in Table 11, with later years for each scenario shown in Table 57and Table 58 in Appendix C.

Table 11 Fuel savings for dispatchable generators value in low scenario 2018/19 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Gas fuel cost ($/GJ)	9.68	9.68	9.68	-	-	-	-
Diesel fuel cost ($/L)	-	-	-	-	-	1.48	1.48
Reduced gas usage (MWh)	165,052	247,579	99,031	-	-		
Reduced diesel usage (MWh)						229	229

5.5 Maximising intermittent generator utilisation

Maximising the utilisation of intermittent generators means delivering more energy to the consumer using the same installed generation equipment. Solar PV and wind generators are intermittent due to their power output being dependent on volatile inputs, the amount of sunshine and wind at any one time. When the power inputs are high, these generators may produce more electricity than what can be exported, forcing the generator output to be curtailed. This curtailment can be viewed as lost energy that would have otherwise been sold in the wholesale market or later used by consumers. BESS can be used to reduce this curtailment impact by storing some of the energy that would have otherwise been curtailed, up to the rated output of installed BESS assuming an average BESS charge of 50%. It can then deliver some of the stored energy to consumers, assuming around-trip efficiency (RTE) of 92%.

South Australia has the highest penetration of wind generation in the NEM. Currently, wind generators in South Australia experience a 6% curtailment rate [27]. We anticipate that the wind penetration for the other regions of the NEM will increase to levels close to the current penetration in South Australia. The analysis distributes the South Australian curtailment rate across the NEM's wind generation and is held constant over the duration of the analysis. We have assumed that in most cases that wind curtailment events will continue to be longer than 2 hours and as such the amount of excess wind energy that can be stored by BESS is limited to the lower of total curtailed wind generation in each year, or the installed BESS capacity in each deployment pathway, assuming an average charge state of 50% and an RTE of 92%. Increasing the utilisation of the asset also means increased degradation based on the increased MWh of generation, which is reflected in the price saving per MWh by deducting the variable opex from the LCOE of wind, shown in Table 12 [28]. The analysis has not considered other system strength issues provided by BESS or plant safety issues.

These savings can only be realised by grid BESS. Garage BESS would be able to provide these savings if a sophisticated demand response mechanism was closely related to wind generation capacity and the dispatch market, which we do not foresee being realised before 2040. The estimated savings of increased wind generator utilisation in the low scenario for 2018/19 is summarised in Table 12 below, with later years for each scenario shown in Table 60 in Appendix C.

Table 12 Increased wind generator utilisation in low scenario 2018/19 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Wind generator LCOE less variable opex ($/MWh)	57.33	57.33	57.33	-	-	-	-
Wind energy not curtailed (MWh)	302,303	302,303	183,899	-	-	-	-

For utility-scale solar, BESS may be able to provide inertia like services that will prevent curtailment and replace synchronous condensers (Syncon). Any further underutilisation of solar has been accounted for in section 5.5. Syncons are installed to counter the non-synchronous nature of wind and solar PV generators by providing inertia and fault current to the local network [29]. BESS are able to reduce the capacity of syncon installations in the NEM. To calculate the offset value, it is assumed that 90 MVAr of syncon is installed per 1450 MW of utility-scale solar PV installations, at a cost of $30M per unit. These values are derived from recent AECOM projects.

These savings can only be realised by grid BESS where BESS have the capability to provide an inertial response; we anticipate that this will be a standard BESS capability in the short term. The estimated savings of increased solar utilisation in the low scenario for 2019/20 is summarised in Table 13, with later years for each scenario shown in Table 61 in Appendix C.

Table 13 Increased utility-scale solar PV generator utilisation in low scenario 2019/20 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Syncon cost per new MW of utility solar PV installed ($/MW)	20,690	20,690	20,690	-	-	-	-
Utility solar PV installed per year (MW)	200	200	200	-	-	-	-

For behind the meter solar PV, additional generation that is not consumed or exported is effectively lost. BESS can be used to store excess generation for later consumption or export, reducing the amount of energy lost. The amount that BESS can increase the utilisation of behind the meter solar, 30% [30], is multiplied by the LCOE of a 5kW residential solar PV system [31].

These savings can only be realised by garage BESS because of export limitations. The estimated savings for maximising behind the meter solar PV utilisation in the low scenario for 2018/19 is summarised in Table 14, with later years for each scenario shown in Table 59 in Appendix C.

Table 14 Increased behind-the-meter solar PV utilisation in low scenario 2018/19 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Solar PV LCOE ($/MWh)	-	-	-	113.33	113.33	113.33	113.33
Increased solar PV utilisation per year (MWh)	-	-	-	76,173	76,173	63,477	63,477

5.6 Reduced T&D power losses

T&D power losses occur as power is transferred from one location to another. Most of the losses in the T&D networks occur at the distribution level, where power is transferred over lower voltages, with higher power losses. BESS can be used to reduce the peak flow through T&D power lines and reduce peak demand on the network that offset some T&D power losses.

We assume that one unit of HV BESS can reduce peak demand at its connection point in the network by 4%, which we further assume has a linear relationship with reduced power losses [32]. As with T&D capex/opex avoidance and deferral, the amount that each deployment pathway can offset T&D losses is estimated by the applicable planning diversity factor. The diversity factor describes the relationship between coincident impact of the BESS operation throughout the supply chain, the lower the BESS connection along the electricity supply chain, the less the BESS can be used to reduce T&D power losses. The estimated diversity factor is multiplied by the potential annual reduction in power losses detailed in Table 62.

The cost of power losses is represented by the 5-year average wholesale price of electricity, shown in Table 15. This is selected based on the losses representing the opportunity cost of having to generate additional electricity to account for the energy losses.

The estimated savings of reduced T&D power losses in the low scenario for 2018/19 is summarised in Table 15, with later years for each scenario shown in Table 62 in Appendix C.

Table 15 Reduced T&D power losses value in low scenario ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Wholesale price ($/MWh)	80.80	80.80	80.80	80.80	80.80	80.80	80.80
Estimated diversity factor (%)	100	80	64	50	50	50	50
BESS offset T&D power losses (MWh)	286,016	286,016	286,016	286,016	286,016	286,016	286,016

Voltage regulation is included in section 5.8 and so has not been included in this calculation.

5.7 Reduced USE

Customers experience supply interruptions, which are inconvenient and may cause safety issues, loss of income and food or material spoilages. USE is an estimate of the electricity that would otherwise have been used by customers, but for a supply interruption (power cut) [33]. BESS will prevent consumers from seeing interruptions, depending on where the BESS are located and where the interruption occurs.

BESS will only be able to reduce USE in specific network configurations and protect from specific types of network failures.

On radial networks, BESS can only reduce USE caused by an upstream component. There is a high correlation between the SAIDI and SAIFI experienced by a consumer and the radial nature of the line. In this configuration, the BESS requires the technical capability to operate in an islanded mode; of the five utility scale BESS currently installed in the NEM only one has this capability. Further, the BESS needs to be sized to match local load or be part of a scheme that also includes some demand response. The costs to reconfigure the network have not been included in this analysis.

A more meshed line provides greater opportunities for switching but may still be limited by the capacity of the line utilised to provide alternative supply in the event of an outage. In this case any downstream BESS can still operate and provide power after the constraint point.

Outages higher up in the network affect more customers, but generally have shorter durations and lower frequency.

HV BESS have the technical capability to reduce USE; the existing ESCRI HV BESS is reducing USE on a 132kV line to wattle point. However, the analysis HV will not be able to reduce USE because the transmission network operators are forecasting no USE so there is no potential value to be realised.

A BESS needs to have charge in order to reduce USE. In some cases, a network may contract some capacity of a BESS to remain charged to prevent USE in the event of an outage, but more likely the majority of BESS will opportunistically provide capacity to reduce USE in the event of an outage if a market is made available for them to do so. The analysis assumes an average charge of 50% and RTE of 92%, and that batteries reduce USE on an opportunistic basis, i.e. when they are charged.

USE is not evenly distributed across the network; poor performing feeders result from failures of degrading assets that were all installed at a similar time and are subject to fail in proximity. The analysis assumes that BESS will be installed on the poorest performing feeders and as such will have a reasonably high impact. In the aggregate SAIDI and SAIFI data, 38% of USE was caused by asset failures. In calculating the offset interruptions, we have assumed that BESS can address all asset failures, but no other interruption causes. This will overstate the ability of BESS to address asset failures and understate the other causes but is likely to determine the right overall magnitude.

The locational variability of USE is also a likely driver of battery investment for households. Households experiencing high frequency of interruption are more likely to purchase a BESS. If wired appropriately, a battery at a customer premises can provide power to that premises when there is an outage on the local network. This analysis assumes that garage BESS will provide backup power only to the household or site on which it is installed and that no micro-grid style VPPS will develop by 2040.

The amount of USE within the NEM is taken from the DNSPs annual reporting which discloses the USE on their network over the course of one year. This analysis sums USE for all DNSPs in the NEM in 2017/18, which was then assumed to adjust over the duration of the analysis based on the maximum demand in the NEM. This value was slightly higher than the reliability standard which defines 0.002% of total demanded energy as the maximum expected quantity of USE.

The cost of USE is determined by the value of customer reliability (VCR). VCR is the price a customer is willing to pay for the reliable supply of electricity. The residential and C&I VCRs, determined by AEMO, are used to measure the benefit derived from BESS reducing the amount of energy demanded but not supplied [34].

The estimated savings of reduced USE in the low scenario for 2018/19 is summarised in Table 16, with later years for each scenario shown in Table 63 in Appendix C.

Table 16 Value of Customer Reliability in low scenario ($/kWh, $, 2013/14)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Residential	-			25.95	25.95	-	-
C&I	-			-	-	45.48	45.48
Network		38.43	38.43				

Table 17 Energy provided by BESS during USE events in low scenario 2018/19 (MWh)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Annual energy provided	-	17.3	65.6	21.61	21.61	7.58	7.58

5.8 Reduced NSCAS costs

NSCAS is procured by TNSPs and, when required, by AEMO to maintain power quality in the transmission network. There are two types of NSCAS payments — payments for reactive power support and payments for load-shedding. BESS can be configured to provide or absorb reactive power and reduce the need for load-shedding by providing stored power to the network in periods of high demand.

There is no expected capacity for BESS to provide NSCAS services in the NEM for the next five years due to the limited number of NSCAS contracts procured in this period. We further assume that BESS will not be used for NSCAS through to 2038/39 due to the nature of the existing long-term contracts and likelihood that BESS won't be the lowest cost NSCAS provider [35].

The price of NSCAS is taken as the average of payments made from 2013-14 to 2017-18 [36] (see Table 18).

Table 18 Reduced NSCAS costs value, all scenarios ($, 2018)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
NSCAS cost ($/MVAr)	11,521	11,521	11,521	11,521	-	11,521	-
NSCAS from BESS (MVAr)	0	0	0	0	-	0	-

5.9 Reduced FCAS costs

FCAS is required by AEMO to match demand and generation within the NEM such that the network operates within a stable frequency range, which is facilitated by the FCAS regulation and contingency markets. The regulation market ensures ongoing frequency stability control is available, while the contingency market is used for responding to contingency events that require reserve capacity to counteract potential changes in frequency in three different time intervals — 5 seconds, 60 seconds and 5-minutes. BESS are well suited to provide frequency control services by responding to market signals to increase or reduce energy being supplied to the network. This has been observed with the Hornsdale battery in South Australia [37].

Currently, AEMO procures only a small amount of regulation services each year — less than 200MW for both raise and lower regulation services. Traded regulation volumes are likely to increase proportionally to the amount of VRE in the NEM.

The contingency market trades in larger volumes than the regulation market, up to 750MW in anticipation of contingency events, this volume is unlikely to significantly increase in the near future and so does not change over the analysis period.

BESS can bid in all regulation and contingency markets, except for garage BESS which must be aggregated and can only participate in contingency markets. The installed BESS is assumed to be able to offset all traded FCAS volumes up to the installed BESS rated output. An average charge of

50% and RTE of 92% are applied to determine the number of BESS that are able to respond, but only impact the traded volume in the early years of each scenario. The analysis assumes that each BESS can provide the same amount of FCAS services per MW installed.

The quantity of BESS in each scenario will likely significantly lower the prices of FCAS services in every market, as was seen after the commissioning of the Hornsdale Power Reserve in South Australia. FCAS prices from 2017 to 2019 have been used to determine an average price in $/MWh for each market. With increased competition in the markets, FCAS prices are likely to reduce from their current highs and stabilise at a lower price [38]. The analysis assumes that the FCAS prices in each market reduce exponentially to 10% of current values by 2040.

The estimated savings in the FCAS markets for 2018/19 is summarised in Table 19, with later years shown in Table 64 and Table 65 in Appendix C. The resulting value is an optimistic approach to valuing BESS as an FCAS provider, as it is assumes that the entire traded value is a net benefit to the network.

Table 19 Reduced FCAS costs in low scenario 2018/19 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
FCAS regulation ($/MWh)	55.39	55.39	55.39	-	-	-	-
FCAS contingency ($/MWh)	26.53	26.53	26.53	26.53	-	26.53	-
BESS regulation volume (MWh)	3,011,860	3,011,860	3,011,860	-	-	-	-
BESS contingency volume (MWh)	20,790,958	20,790,958	20,790,958	20,790,958	-	20,790,958	-

5.10 Reduced SRAS costs

System Restart Ancillary Services (SRAS) are a key instrument in ensuring the resilience of the NEM power system and returning power after a system-black event. SRAS is procured by AEMO, who is responsible for ensuring that there is sufficient SRAS available to restart the system throughout the year by establishing contracts for SRAS at several locations around the NEM. BESS connected on the HV network could provide SRAS by providing stored energy to restart nearby larger generation plant.

There are currently 12 SRAS providers contracted across the NEM which are selected based on their location and network restart capabilities. To date, no BESS have been contracted to provide SRAS. At this stage, no installed BESS have black start capability. Most BESS have grid following inverters that cannot establish their own voltage source and require an operating grid with a number of nearby synchronous generation units to establish stable operation. A number of BESS under development are proposing to install grid-forming inverters, which will function similarly to a synchronous generator, from a system restoration perspective, and may prove capable of restarting the grid.

Despite the potential for BESS to operate as an SRAS provider, it is unlikely that commercial BESS owners will engage in this market due to lower economic returns in the SRAS than what can be achieved in other markets. Further, competition from less capital-intensive generators would likely mean that BESS prices are too high to be competitive to secure SRAS contracts.

This study assumes that only a small number of installed HV BESS installed will have the capability to provide these services, having grid forming inverters, storage capacity, the required location, connection to other plant, response times and communications requirements.

SRAS costs are made up of three payment types — availability, testing and usage. Most SRAS payments are availability payments made to the contracted SRAS providers throughout the year, with a smaller proportion of the costs associated with testing and the provision of SRAS in the event of a blackout. The SRAS provider price is an average of 2017/18 actual costs and the 2018/9 cost estimates [36].

AEMO has recently initiated a rule change regarding SRAS which is likely to result in a mandatory SRAS product that is likely to deplete the existing SRAS market. The analysis assumes that this product will be in operation by 2021 and no value will be realised by BESS from this date.

The value of reduced SRAS costs is then the number of offset SRAS providers multiplied by the annual cost per provider, these values provided in Table 20 for the high scenario in 2018/19. Later years are shown in Table 66 in Appendix C. This result is an optimistic approach to valuing BESS as an SRAS provider as it is assumes that the entire offset cost is a net benefit to the network.

Table 20 Reduced SRAS costs value in low scenario 2019/20 ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
SRAS annual costs per provider	2,595,336	-	-	-	-	-	-
SRAS providers offset	1	-	-	-	-	-	-

5.11 Commercial values

The owners and operators of batteries can realise specific commercial returns from a BESS that do not necessarily provide system benefit, but move value from one party to another.

5.11.1 Wholesale revenue

Energy storage, including BESS, has the ability to earn revenue by buying energy to charge when prices are low, and discharging energy to sell when prices are high. The analysis applies a market model to each BESS pathway, utilising a priced based behavioural model to determine when the BESS is most likely to charge or discharge. This model has been applied to actual wholesale prices from 2014-18, calculating the annual revenue over the four years in each state. Our analysis uses the maximum demand in each state to calculate a demand-weighted average annual revenue in the NEM, the results shown in Table 21. Garage BESS could access wholesale revenue through a VPP, but this would be at the expense of tariff arbitrage. Consumer tariff arbitrage is calculated in section 5.11.3.

Table 21 Wholesale revenue per BESS unit ($, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Wholesale revenue	859,690	982,134	713,407	-	-	-	-

5.11.2 PPA firming

In addition to the wholesale market, BESS can trade electricity through PPAs — private contracts for the purchase of electricity. This study assumes that the increase in PPA prices is reflective of the level of revenue for wholesale prices, described in section 5.11.1.

5.11.3 Consumer tariff reduction

Garage BESS can allow consumers to better manage their electricity bills by reducing their electricity consumption from the grid, especially at times of high grid demand and high tariff prices. Tariffs generally consist of a fixed access charge and a variable consumption charge. Analysing all the available network charges for DNSPs in the NEM, and we found that all were a combination of flat rate, ToU and demand charges [39]:

- Flat rate tariffs charge the customer a fixed price per kilowatt-hour of electricity consumed
- TOU pricing applies a varying price per kilowatt-hour of electricity consumed, usually having a peak, shoulder and an off-peak price; the retail price theoretically reflects time-based factors including the wholesale costs and network costs driven by the average demand on the network during that period
- Demand tariffs are based on a customer's maximum demand at a specific time, i.e. when they are using the most electricity, within a specified period [40]. For C&I customers, this rate also takes into account their power factor, meaning demand is measured in kVA rather than kW.

Our analysis assumes that retail products offered to consumers include these types of tariff structures and that owners of BESS are likely to sign up for them. Where BESS owners do not sign up for these specific products, we assume that the products they do sign up for reflect the savings that the retailer is realising from the BESS behaviour.

We determined the value of consumer tariff reduction by considering a typical residential and C&I customer under the three tariff structures. Because each DNSP has unique tariff rates, we have selected a representative tariff for each tariff type from Powercor, Essential Energy and SAPN's 2019-20 prices [41] [42] [43]. It was assumed that each customer installing BESS also has rooftop solar PV installed capable of generating up to 80% of their total consumption. BESS can store the excess solar PV generation during the day and use the energy to reduce their consumption from the grid overnight, with a round trip efficiency (RTE) of the BESS applied, which is assumed to be 92%. The system sizes assumed means that no solar generation is exported to the grid. A typical residential customer was developed having a 5kW/12.5kWh BESS, 5kW solar PV, and 15kWh daily consumption. The results show that one unit of CR/CCI BESS can impact TOU tariff prices most, with annual customer bill reductions shown in Table 22 and Table 23.

Table 22 Consumer tariff reduction value for residential customers (per household with installed BESS, $, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Flat savings	-	-	-	260	260	-	-
TOU savings	-	-	-	874	874	-	-
Demand savings	-	-	-	71	71	-	-

Similarly, a C&I customer profile was created with a 100kW/300kWh BESS, 100kW solar PV, and 300.5kWh of daily consumption. C&I tariffs often include mixtures of demand, TOU and flat pricing — but we have considered examples of tariffs that isolate these tariff types. Flat and TOU tariffs are shown to benefit C&I customers the most, as shown in Table 23.

Table 23 Consumer tariff reduction value for C&I customers (per C&I site with installed BESS, $, 2019)

Item	HV	MV	LV	CR	NCR	CCI	NCCI
Flat savings	-	-	-	-	-	8,844	8,844
TOU savings	-	-	-	-	-	22,010	22,010
Demand savings	-	-	-	-	-	4,811	4,811

Note that each household will achieve only one of these value streams, or a component of each of them. The analysis assumes an equal split between all three tariff types. Extending the analysis to consider a larger representation of tariffs applied in the NEM may be investigated following this study.

6.0 Value stacking

One of the key features of BESS are their ability to provide multiple services. These services may be provided simultaneously, or the BESS might switch between functions in response to technical needs or commercial incentives. Not all value streams can be accessed by the same BESS, because of technical, operational or market constraints.

There are many ways that BESS services can be stacked to benefit the network or BESS owner. The driver for value stacking will depend on the asset operators' priorities and approach to risk and may require a complex trade-off analysis to optimise returns. The technical ability to provide more than one service does not necessarily translate to a commercial incentive to provide those services. Value stacking in practice usually reflects commercial incentives, and so certain services are unlikely to be provided unless market or regulatory changes are made to provide these incentives (e.g. FFR).

A BESS that trades on the wholesale market cannot provide FCAS raise services when the BESS is discharging at full capacity or FCAS lower services when the BESS is charging at full capacity. Conversely, a BESS that is contracted to provide demand management for a network will not be required for that function continuously throughout the day or the year. In periods where there is no risk of demand exceeding a certain threshold, the BESS may provide other services such as trading in the wholesale and FCAS market.

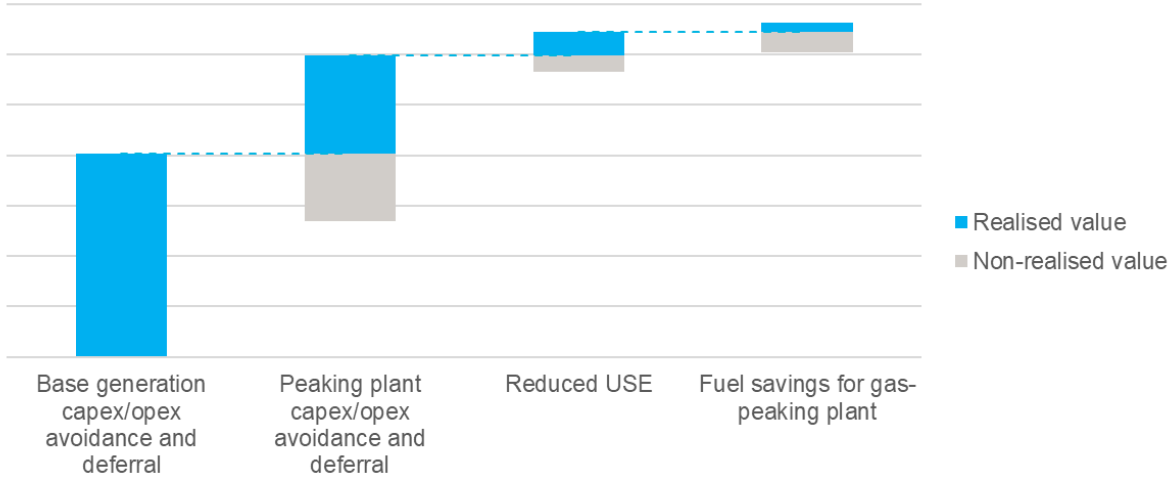
SRAS providers are contractually required to meet the minimum availability/reliability and technical requirements for the duration of the SRAS contract [44]. These requirements generally prohibit BESS from providing in other services.

Our analysis considers one possible value stack which prioritises services based on the bankability of services; i.e. the willingness of well-established financial institutions to finance a project or proposal at a reasonable interest rate. For large scale projects that require both debt and equity funding, this translates to a level of assurance that a return will be provided for the given service. This prioritises direct contract for capacity and availability, and then open markets in order of volatility.

We anticipate that a BESS preventing or reducing capex would either be a direct saving to a business or be able to access a capacity payment under a contract to provide this service. Similarly, we anticipate that BESS providing a direct network service will be able to access an annual revenue under a direct contract. Lastly, we have assumed that the variability in ancillary service volumes and costs makes the return from these services most volatile. When BESS is being used to offset base generation capex, then the value stream of deferring peaking plant capex, fuel savings for dispatchable generators and reducing FCAS costs are only available when the BESS is charging (or discharging for lower services). In the medium, high and rapid transformation scenarios this limits the three value streams to approximately 60% of their maximum potential. Similarly, when BESS are used to offset peaking plant capex, BESS can only access approximately 50% of the fuel savings for dispatchable generators and FCAS value streams in the high and rapid transformation scenarios. Finally, BESS used for fuel savings for dispatchable generators can't simultaneously provide FCAS in any scenario, based on the installed capacity of gas peakers relative to installed BESS capacity.

Commercially and economically, this means that the revenue that may be realised by a BESS is not the sum of the available revenue streams, as shown in Figure 19. The values provided by the economic assessment present both the potential revenue streams that may be accessed and a stacked revenue.

Figure 19 BESS value stack principle (example)



7.0 Economic assessment

The technical analysis in Section 5.0 and 6.0 showed the value of services which could be potentially provided by BESS across myriad service streams, including those services which are able to be provided in a composite or stacked manner. Building on this evaluation, this section assesses the economic performance of the seven deployment pathways.

The assessment applies a social cost benefit framework which is a common method of appraising large scale investment projects. Here, it is important to recognise that each of the pathways effectively represents a separate large scale infrastructure project; multiple BESS units of different forms are progressively installed over a 20-year period to realise a BESS capacity of 37.5MWh. The pathways differ in terms where in the system the BESS are connected, as well as their respective cost structures and the scenarios differ in terms of their installation rates.

The economic assessment involves estimating all the private and external costs and benefits of alternative deployment options and identifying which option(s) have the highest net benefit.

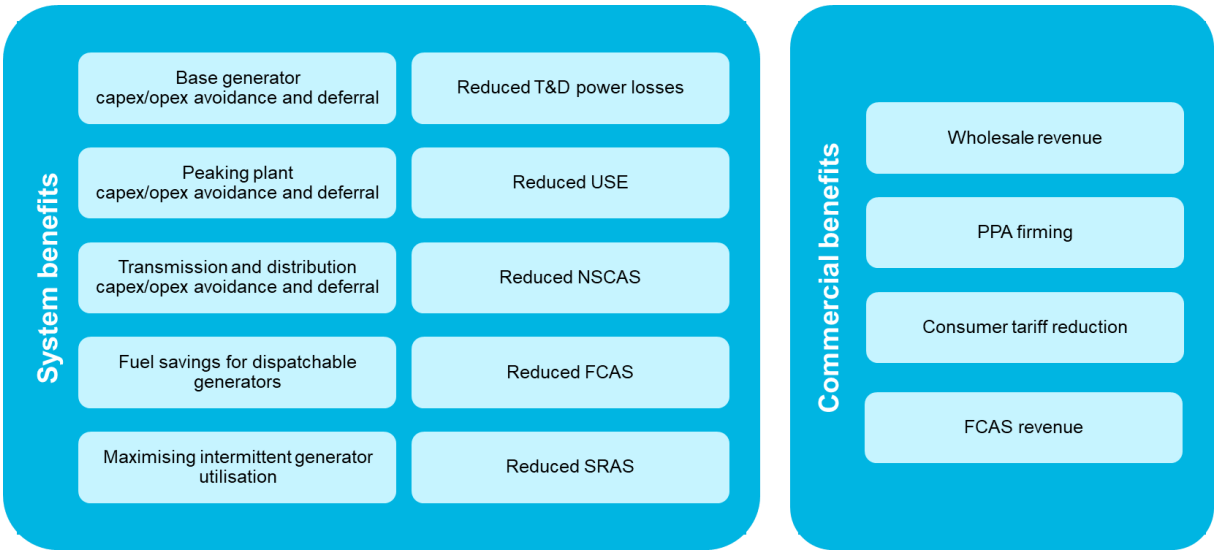
7.1 Framework

The economic assessment compares the costs and benefits of each pathway under each scenario, as shown in Figure 21. Annual capex and opex of respective BESS deployments were estimated, as detailed in section 3.0; taking account of respective asset lives, replacement requirements and timing. These were set against the quantified benefits for each pathway (discussed in section 5.0).

The four scenarios (Low, Medium, High and Rapid transformation) reflect different energy market environments, with different market conditions such as peak electricity demand, population and new technology adoption. Such factors also drive different BESS deployments. As the scenarios move from low to high, the rate of BESS deployment increases, with higher costs but also earlier realisation of benefits. The scenarios are detailed in section 4.2.

The benefits of BESS deployments have been split into system benefits and commercial benefits to distinguish between the wider system benefits and those which accrue to the owner of a system. The benefit streams are discussed in section 5.0.

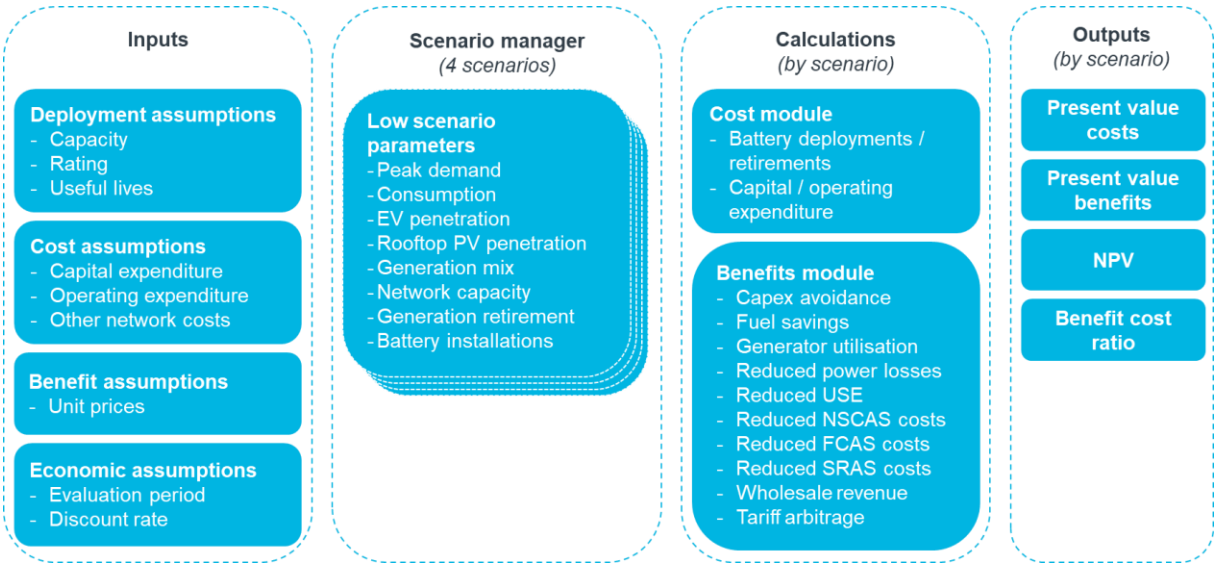
Figure 20 BESS system and commercial benefits



The economic values of costs and benefits for each pathway are forecast over the period FY2019-FY2038. The costs are offset from benefits on an annual basis, and the resulting net impacts are discounted to present values, as at 30 June 2019, at a real discount rate of 4%.

The NPV allows pathways to be compared on the same basis and allows for the determination of the greatest net benefit to the community or the most economic use of resources.

Figure 21 Economic assessment framework



7.2 BESS costs across the deployment pathways

The economic modelling has considered three cost components, capex, opex and other network costs (orchestration and low voltage management costs associated with controlled, behind the meter systems). Costs for each of the seven pathways are determined based on the rates as presented in section 3.3, Table 4. A cost reduction factor was applied to the battery proportion of capex, to realise the reduction in the cost of batteries over the period analysed. The grid BESS pathways (HV, MV and LV) have the highest opex, as shown in Table 24, which is reflective of the performance and testing requirements applicable to utility-scale storage. The residential systems have the highest per unit capital cost as they typically lack the scale efficiencies of larger systems. The other network costs are fixed for each controlled pathway. They account for the cost of orchestration and low voltage management and are not dependant on the number of batteries installed in a given scenario.

Table 24 Deployment pathway cost breakdown for 37.5MWh unit of BESS (2019, $/unit)

Pathway	Capex	Annual opex	Other network costs (fixed, first 5-years)	Other network costs (fixed, second 5-years)
HV	40,371,753	699,111		
MV	38,596,311	621,150		
LV	34,298,156	621,150		
CR	47,026,242	264,146	32,000,000	446,000,000
NCR	47,026,242	264,146		
CCI	35,512,153	330,182	32,000,000	446,000,000
NCCI	35,512,153	330,182		

There is a significant increase in the total BESS deployment costs between the low and medium scenarios for all pathways proportional to the increase number of BESS being deployed, with the exception of the controlled garage pathways (CR and CCI) where the cost of orchestration and low voltage management is diluted as the number of BESS installed increases, as shown in Table 25.

Similarly, the increase in cost between the medium and high scenarios is proportional to the number of BESS deployed for all non-controlled pathways, although the increased is much less marked.

Table 25 Present value costs by scenario and pathway (2019 $billions, real)

Pathway		Low	Medium	High	Rapid trans.
HV	Present value cost	1.89	3.02	3.77	3.77
	Change	-	60%	25%	0%
MV	Present value cost	1.49	2.38	2.97	2.97
	Change	-	60%	25%	0%
LV	Present value cost	1.32	2.12	2.65	2.65
	Change	-	61%	25%	0%
CR	Present value cost	2.04	3.07	3.75	3.75
	Change	-	50%	22%	0%
NCR	Present value cost	1.70	2.72	3.40	3.40
	Change	-	60%	25%	0%
CCI	Present value cost	1.70	2.52	3.06	3.06
	Change	-	48%	21%	0%
NCCI	Present value cost	1.36	2.18	2.72	2.72
	Change	-	60%	25%	0%

7.3 Low scenario

In the low scenario, the changes in Australia's energy market over the next 20 years are relatively benign. Economic and population growth are weak, and peak electricity demand decreases. BESS deployment is consequently moderated, with low investment costs across all pathways, as shown in Figure 22 and Table 26.

Figure 22 Low scenario present value total costs by pathway (2019 $billions, real)

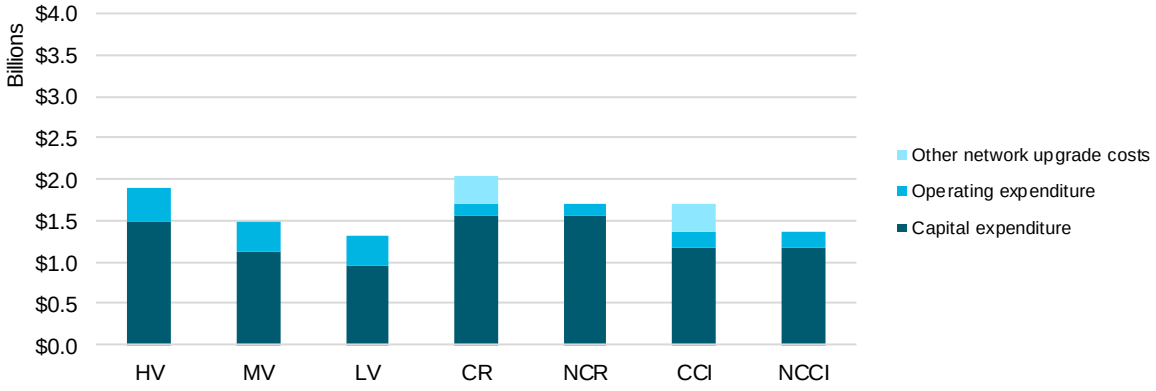


Table 26 Present value cost of pathways low scenario (2019 $billions, real)

Pathway	Capex	Opex	Other network upgrade costs	Total
HV	1.48	0.41	-	**1.89**
MV	1.13	0.36	-	**1.49**
LV	0.96	0.36	-	**1.32**
CR	1.55	0.15	0.34	**2.04**
NCR	1.55	0.15	-	**1.70**
CCI	1.17	0.19	0.34	**1.70**
NCCI	1.17	0.19	-	**1.36**

7.3.1 Low scenario pathway system benefits

The system benefits potentially generated by each pathway in the low scenario are generally greater further up the supply chain, as shown in Figure 23 and Table 27. The value realised for reduced T&D power losses reduces down the supply chain.

The analysis shows that not all benefits are able to be provided by every BESS deployment pathway and the fewest number potential benefits are available from the non-controlled BESS. Controlled BESS have the potential to provide significant value in FCAS savings, accounting for more than half of the potential benefit of each of these pathways.

Grid BESS are able to maximise the use of intermittent utility scale generation. Garage BESS are able to maximise the use of intermittent rooftop solar generation at slightly higher values. Distribution capex is only able to be provided by the grid batteries lower than HV, i.e. MV and LV.

The grid BESS pathways are able to provide transmission network capex deferral and fuel savings for dispatchable generators. C&I BESS are also able to provide fuel savings, but the impact is negligible.

Under this scenario none of the pathways are able to provide base generation capex deferral or peaking plant capex deferral because of the forecast reduction in peak demand.

The overall value of reduction of USE is very low in this scenario and is provided at similar levels by all pathways except for LV, which is significantly higher and HV which provides none of this value.

Figure 23 Low scenario present value total potential system benefits by pathway (2019 $billions, real)

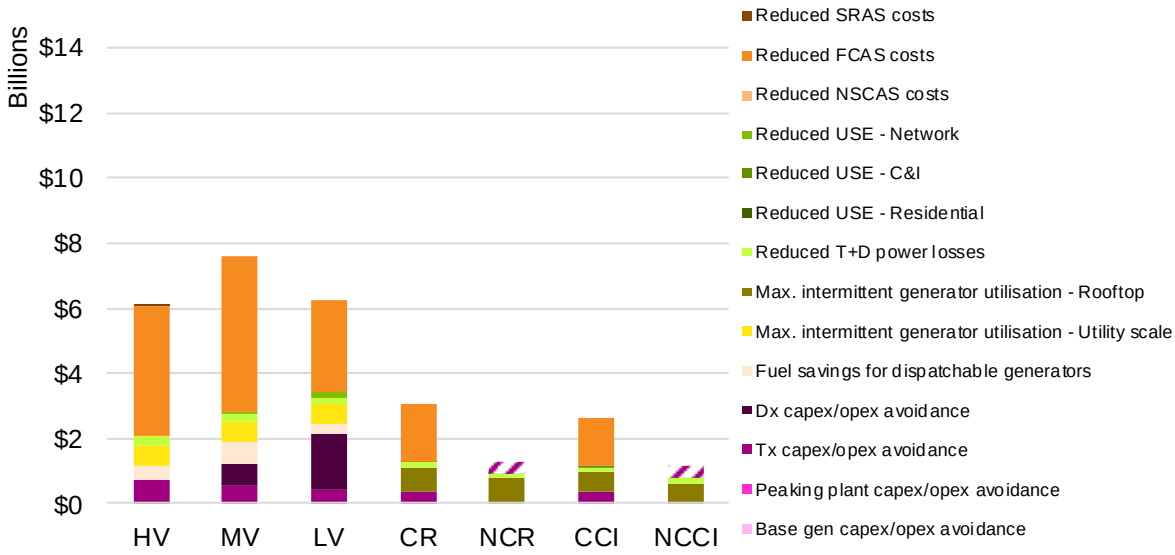


Table 27 Total potential system benefits of pathways low scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	-	-	-	-	-	-	-
Peaking plant capex/opex avoidance	-	-	-	-	-	-	-
Tx capex/opex avoidance	0.71	0.57	0.45	0.35	-	0.35	-
Dx capex/opex avoidance	-	0.64	1.71	-	-	-	-
Fuel savings for dispatchable generators	0.47	0.70	0.28	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	0.61	0.61	0.61	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	0.77	0.77	0.64	0.64
Reduced T+D power losses	0.27	0.22	0.17	0.14	0.14	0.14	0.14
Reduced USE - Residential	-	-	-	0.04	0.04	-	-
Reduced USE - C&I	-	-	-	-	-	0.03	0.03
Reduced USE - Network	-	0.06	0.22	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	3.99	4.78	2.78	1.77	-	1.47	-
Reduced SRAS costs	0.00	-	-	-	-	-	-

The ability of BESS to access these value streams simultaneously services was examined. Benefit stacking for the low scenario significantly scales back the realised value from the potential HV, MV and LV pathway benefits as FCAS benefits are only able to be partially realised or not realised at all. All other value streams have remained approximately constant in the low scenario. The FCAS savings in the controlled behind the meter pathways make stacked benefits comparable with the upstream pathways.

Figure 24 Low scenario stacked system benefits summary (2019 $billions, real)

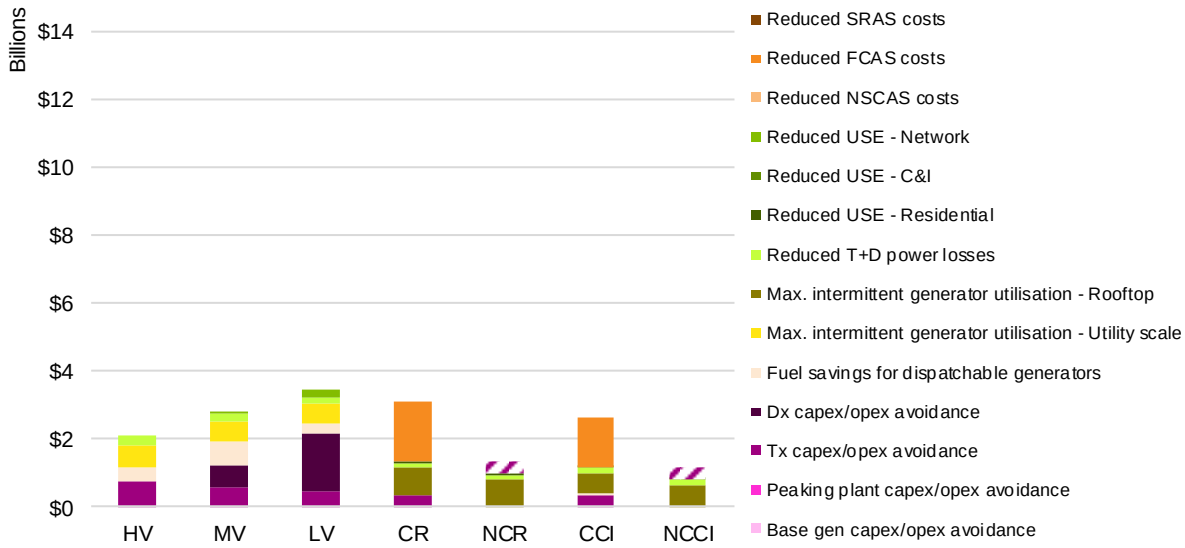


Table 28 Low scenario stacked system benefits by pathway (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	-	-	-	-	-	-	-
Peaking plant capex/opex avoidance	-	-	-	-	-	-	-
Tx capex/opex avoidance	0.71	0.57	0.45	0.35	-	0.35	-
Dx capex/opex avoidance	-	0.64	1.71	-	-	-	-
Fuel savings for dispatchable generators	0.47	0.70	0.28	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	0.61	0.61	0.61	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	0.77	0.77	0.64	0.64
Reduced T+D power losses	0.27	0.22	0.17	0.14	0.14	0.14	0.14
Reduced USE - Residential	-	-	-	0.04	0.04	-	-
Reduced USE - C&I	-	-	-	-	-	0.03	0.03
Reduced USE - Network	-	0.06	0.22	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	-	-	-	1.77	-	1.47	-
Reduced SRAS costs	-	-	-	-	-	-	-
Total	**2.06**	**2.80**	**3.45**	**3.06**	**0.94**	**2.63**	**0.80**

7.3.2 Low scenario pathway commercial benefits

The commercial benefits to asset owners estimated for each pathway in the low scenario are dominated by FCAS savings (see Figure 25). Consumer tariff reductions add to the commercial benefits for the garage pathways, however these are greatly outweighed by FCAS savings. The MV pathway has the greater commercial benefit of around $4.8 billion in present value terms, followed by the HV pathway with $4 billion. PPA firming and wholesale revenue benefits are negligible.

Figure 25 Low scenario present value commercial benefits by pathway (2019 $billions, real)

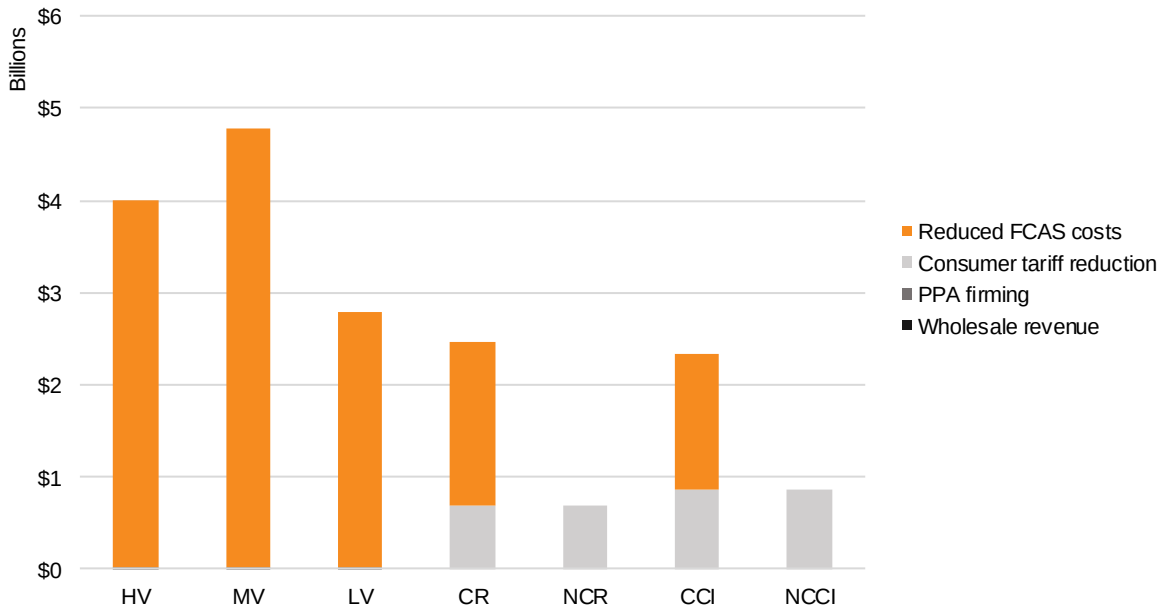


Table 29 Commercial benefits of pathways low scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Wholesale revenue	0.01	0.01	0.01	-	-	-	-
PPA firming	-	-	-	-	-	-	-
Consumer tariff reduction	-	-	-	0.70	0.70	0.86	0.86
Reduced FCAS costs	3.99	4.78	2.78	1.77	-	1.47	-
Total	**4.00**	**4.79**	**2.79**	**2.47**	**0.70**	**2.33**	**0.86**

7.3.3 Low scenario pathway NPVs

With a stacked system NPV of $2.13 billion the LV pathway provides the highest system benefit in the low scenario, as shown in Figure 26. The MV and P3-LV pathways also deliver significant value, returning NPVs of $1.31 billion and $1.02 billion respectively. The garage pathways perform poorly in comparison with costs out weighting benefits in the non-controlled cases, primarily due to the lack of FCAS benefits for non-controlled BESS. Residential pathways marginally outperform the commercial and industrial pathways which may be attributed to the tariff structures that are applied to residential premises being more suited to tariff arbitrage.

Commercial NPVs are positive for all pathways that can realise FCAS benefits, as presented in Figure 27. The HV pathways realise major FCAS benefits returning NPVs between $3.3 billion and $1.5 billion. The non-controlled NCR pathway and NCCI pathway return negative NPVs as only consumer tariff reduction benefits are realised.

Table 30 Low scenario pathway NPV (2019 $billions, real)

Pathway	Total potential system benefits	Stacked system benefits	Commercial
HV	4.16	0.17	2.11
MV	6.09	1.31	3.31
LV	4.90	2.13	1.46
CR	1.02	1.02	0.42
NCR	(0.76)	(0.76)	(1.00)
CCI	0.93	0.93	0.63
NCCI	(0.56)	(0.56)	(0.50)

Figure 26 Low scenario stacked system benefit pathway summary (2019 $billions, real)

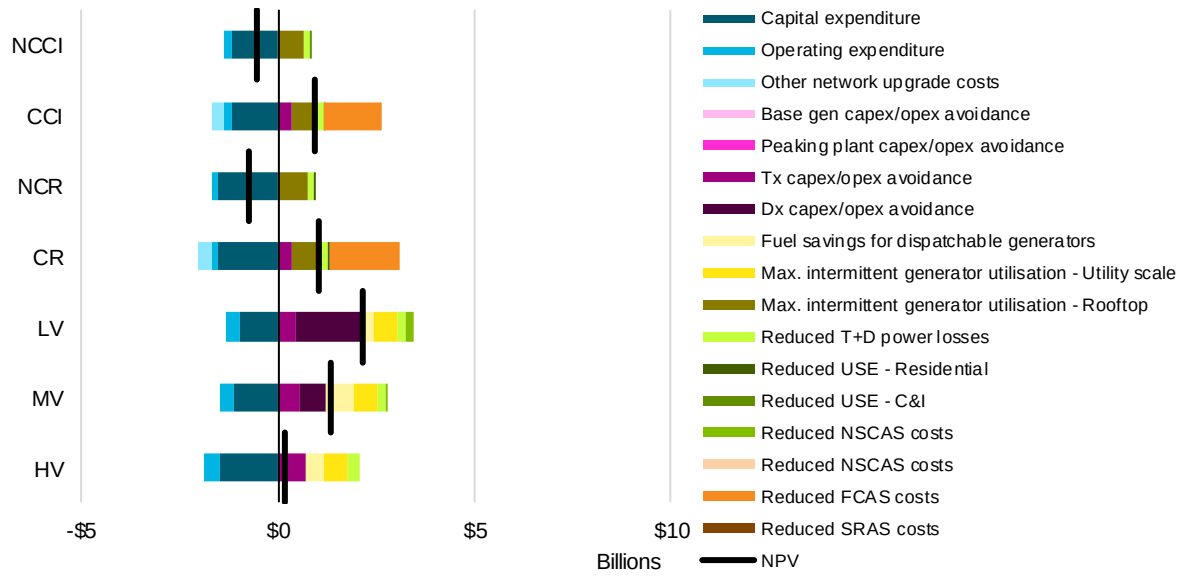
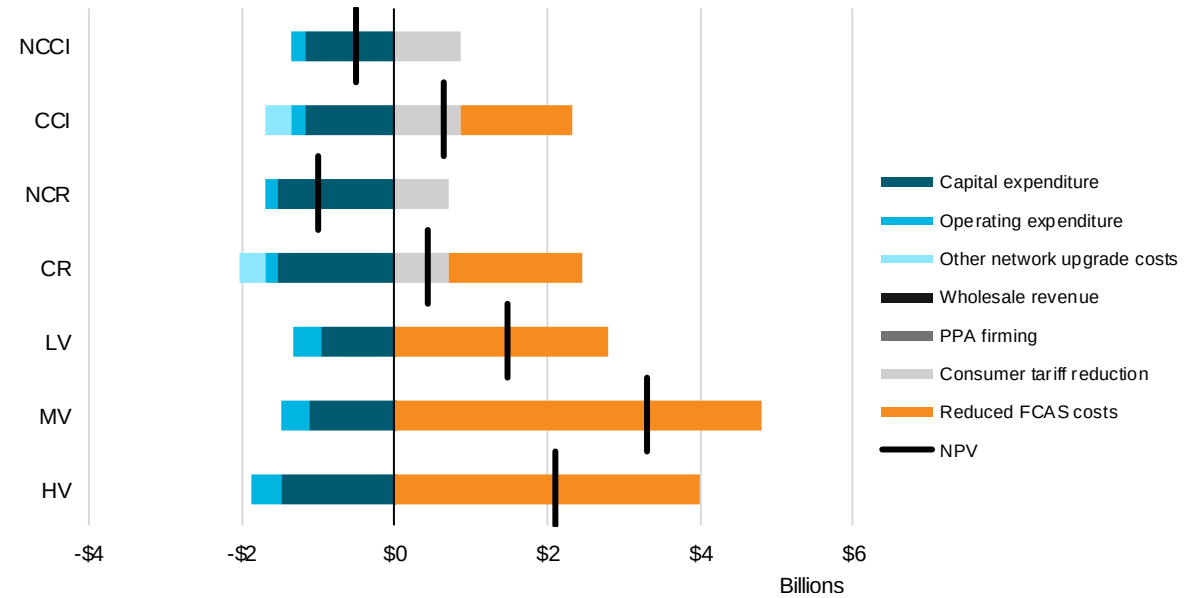


Figure 27 Low scenario commercial pathway summary (2019 $billions, real)



7.4 Medium scenario

In the medium scenario, the changes in Australia's energy market over the next 20 years are moderate. Economic and population growth are largely consistent with long term trends. Electricity consumption is forecast to be around 50% higher than in the low scenario, with a greater proportion from renewable sources. There is greater deployment of storage batteries, with approximately 50% more batteries installed by 2038, which is reflected in higher pathway costs as shown in Figure 28 and Table 31.

Figure 28 Medium scenario present value total costs by pathway (2019 $billions, real)

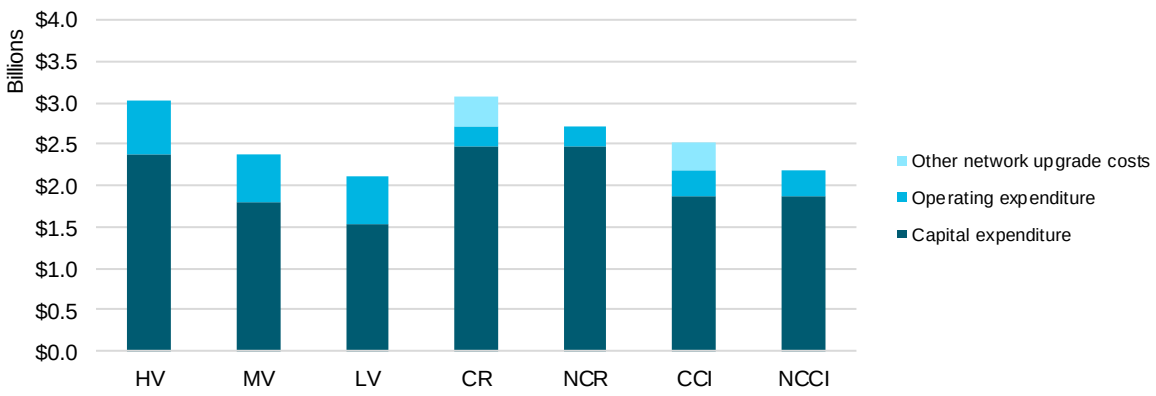


Table 31 Present value cost of pathways medium scenario (2019 $billions, real)

Pathway	Capex	Opex	Other network upgrade costs	Total
HV	2.37	0.65	-	**3.02**
MV	1.80	0.58	-	**2.38**
LV	1.54	0.58	-	**2.12**
CR	2.48	0.25	0.34	**3.07**
NCR	2.48	0.25	-	**2.72**
CCI	1.87	0.31	0.34	**2.52**
NCCI	1.87	0.31	-	**2.18**

7.4.1 Medium scenario pathway system benefits

The system benefits estimated by each pathway in the medium scenario are generally greater as BESS is installed further upstream in the network supply chain, as presented in Figure 29.The value realised for reduced T&D power losses reduces down the supply chain.

The analysis shows that not all benefits are able to be provided by every BESS deployment pathway and the least potential benefits are available from the non-controlled BESS. Controlled BESS have the potential to provide significant value in FCAS savings, accounting for close than half of the potential benefit of each of these pathways. Grid BESS are able to maximise the use of intermittent utility scale generation. Garage BESS are able to maximise the use of intermittent rooftop solar generation at higher values.

Distribution capex is only able to be provided by the grid batteries lower than HV, i.e. MV and LV. The grid BESS pathways are able to provide peaking plant capex avoidance, reflective of the forecast increase in VRE. These BESS pathways are also able to provide transmission network capex deferral and fuel savings for dispatchable generators. C&I BESS are also able to provide fuel savings, but the impact is negligible.

The overall value of reduction of USE is very low in this scenario and is provided at similar levels by all pathways except for LV, which is significantly higher and HV which provides none of this value.

Under this scenario none of the pathways are able to provide base generation capex deferral or fuel savings for dispatchable generators because of the forecast for minimal growth in peak demand.

Figure 29 Medium scenario present value total potential system benefits by pathway (2019 $billions, real)

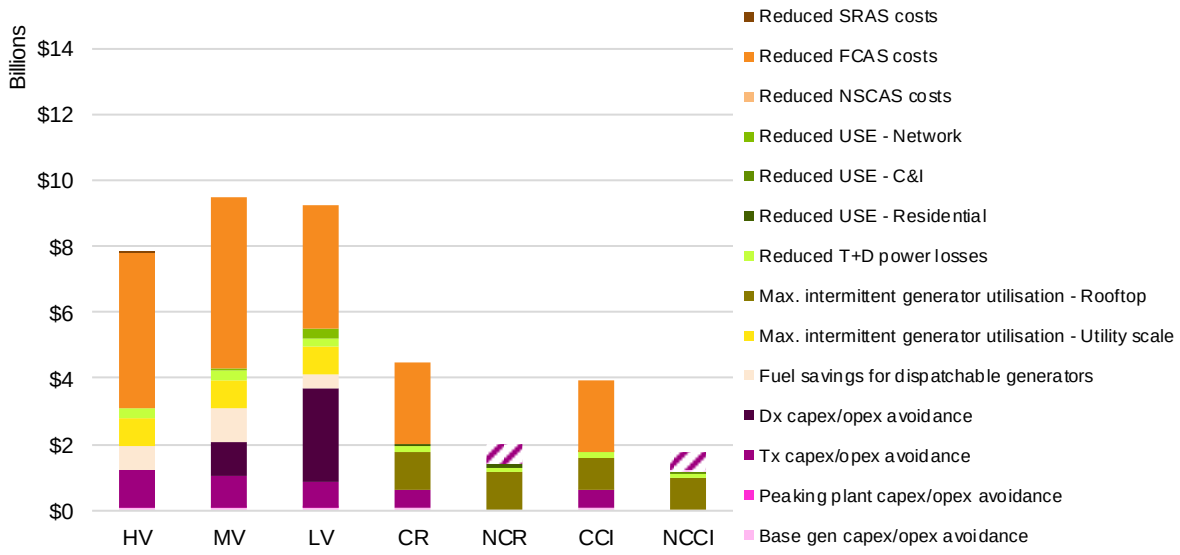


Table 32 Total potential system benefits of pathways medium scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	0.05	0.05	0.05	0.05	-	0.05	-
Peaking plant capex/opex avoidance	0.04	0.04	0.04	-	-	-	-
Tx capex/opex avoidance	1.15	0.92	0.73	0.57	-	0.57	-
Dx capex/opex avoidance	-	1.04	2.88	-	-	-	-
Fuel savings for dispatchable generators	0.70	1.05	0.42	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	0.86	0.86	0.86	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	1.15	1.15	0.96	0.96
Reduced T+D power losses	0.30	0.24	0.20	0.15	0.15	0.15	0.15
Reduced USE - Residential	-	-	-	0.06	0.06	-	-
Reduced USE - C&I	-	-	-	-	-	0.04	0.04
Reduced USE - Network	-	0.09	0.33	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	4.69	5.21	3.75	2.48	-	2.14	-
Reduced SRAS costs	0.00	-	-	-	-	-	-

When the ability to access these value streams simultaneously is considered, the benefits for the HV, MV and LV pathways are significantly scaled back due to the removal of the FCAS benefits. FCAS benefits remain for the controlled garage pathways at a reduced rate of 59% of total FCAS benefits. All other value streams have remained approximately constant resulting in overall value returns ranging from approximately $5.2 billion for the LV pathway to approximately $1.2 billion for the NCCI pathway. The LV pathway returns the highest stacked system benefits with the distribution benefits equating to 55% ($2.9 billion) of the pathway's stacked system benefits.

Figure 30 Medium scenario stacked system benefits summary (2019 $billions, real)

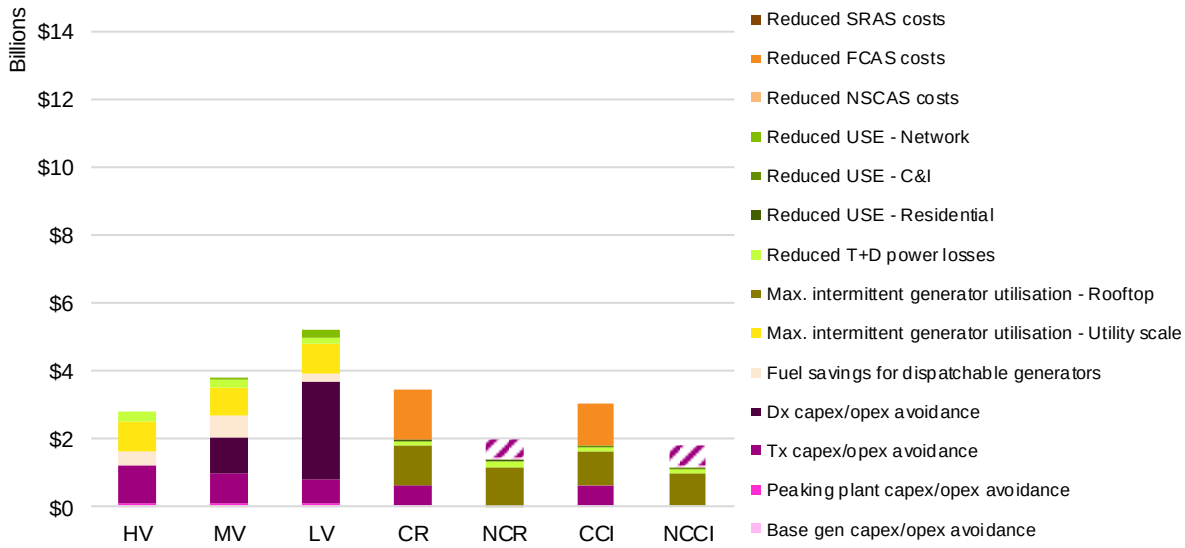


Table 33 Medium scenario stacked system benefits by pathway (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	0.05	0.05	0.05	0.05	-	0.05	-
Peaking plant capex/opex avoidance	0.02	0.02	0.02	-	-	-	-
Tx capex/opex avoidance	1.15	0.92	0.73	0.57	-	0.57	-
Dx capex/opex avoidance	-	1.04	2.88	-	-	-	-
Fuel savings for dispatchable generators	0.41	0.62	0.25	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	0.86	0.86	0.86	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	1.15	1.15	0.96	0.96
Reduced T+D power losses	0.30	0.24	0.20	0.15	0.15	0.15	0.15
Reduced USE - Residential	-	-	-	0.04	0.06	-	-
Reduced USE - C&I	-	-	-	-	-	0.02	0.04
Reduced USE - Network	-	0.05	0.20	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	-	-	-	1.46	-	1.26	-
Reduced SRAS costs	-	-	-	-	-	-	-
Total	**2.80**	**3.81**	**5.19**	**3.43**	**1.37**	**3.03**	**1.16**

7.4.2 Medium scenario pathway commercial benefits

The commercial present value benefits estimated for each pathway in the medium scenario are dominated by FCAS savings, as shown in Figure 31. Consumer tariff reductions add to the commercial benefits for the garage pathways, however these are greatly outweighed by FCAS savings. The MV pathway returns the greater benefit approximately $5.2 billion followed by the HV pathway with $4.7 billion. PPA firming and wholesale revenue benefits are negligible.

Figure 31 Medium scenario present value total commercial benefits by pathway (2019 $billions, real)

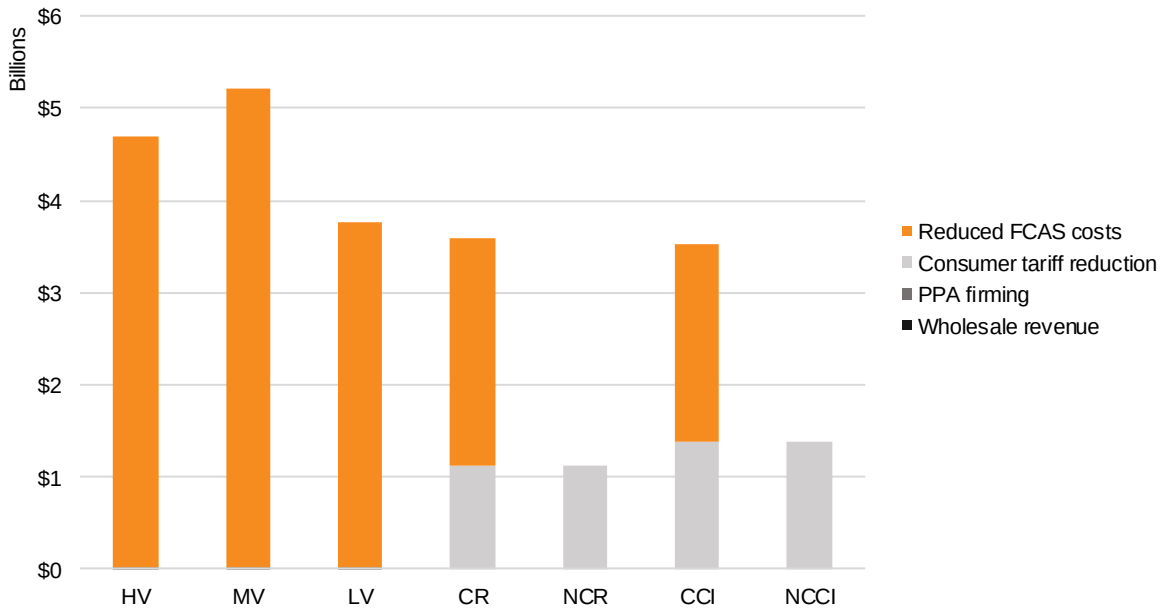


Table 34 Commercial benefits of pathways medium scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Wholesale revenue	0.01	0.01	0.01	-	-	-	-
PPA firming	-	-	-	-	-	-	-
Consumer tariff reduction	-	-	-	1.12	1.12	1.38	1.38
Reduced FCAS costs	4.69	5.21	3.75	2.48	-	2.14	-
Total	**4.70**	**5.22**	**3.76**	**3.60**	**1.12**	**3.52**	**1.38**

7.4.3 Medium scenario pathway NPVs

The MV and LV pathways perform best in the medium scenario, both returning a stacked system NPV of $1.43 billion and $3.07 billion respectively, as shown in Figure 32 and Table 35. The garage pathways perform comparatively poorly, with costs out weighting benefits in the non-controlled cases. Both non-controlled garage pathways return negative NPVs, primarily due to the lack of FCAS benefits which can be realised in the controlled pathways. Residential pathways outperform the commercial and industrial pathways, as they did in the low scenario.

Commercial NPVs are positive for all pathways other than the non-controlled garage pathways, as presented in Figure 33. The HV pathways realise major FCAS benefits returning an overall commercial return of between $2.9 billion and $1.6 billion on a net present basis. The non-controlled NCR pathway and NCCI pathway return negative NPVs as only consumer tariff reduction benefits are realised.

Table 35 Medium scenario pathway NPVs (2019 $billions, real)

Pathway	Total potential system benefits	Stacked system benefits	Commercial
HV	4.78	(0.21)	1.68
MV	7.13	1.43	2.85
LV	7.15	3.07	1.64
CR	1.40	0.36	0.53
NCR	(1.36)	(1.36)	(1.61)
CCI	1.41	0.51	1.00
NCCI	(1.02)	(1.02)	(0.80)

Figure 32 Medium stacked system benefit pathway network summary (2019 $billions, real)

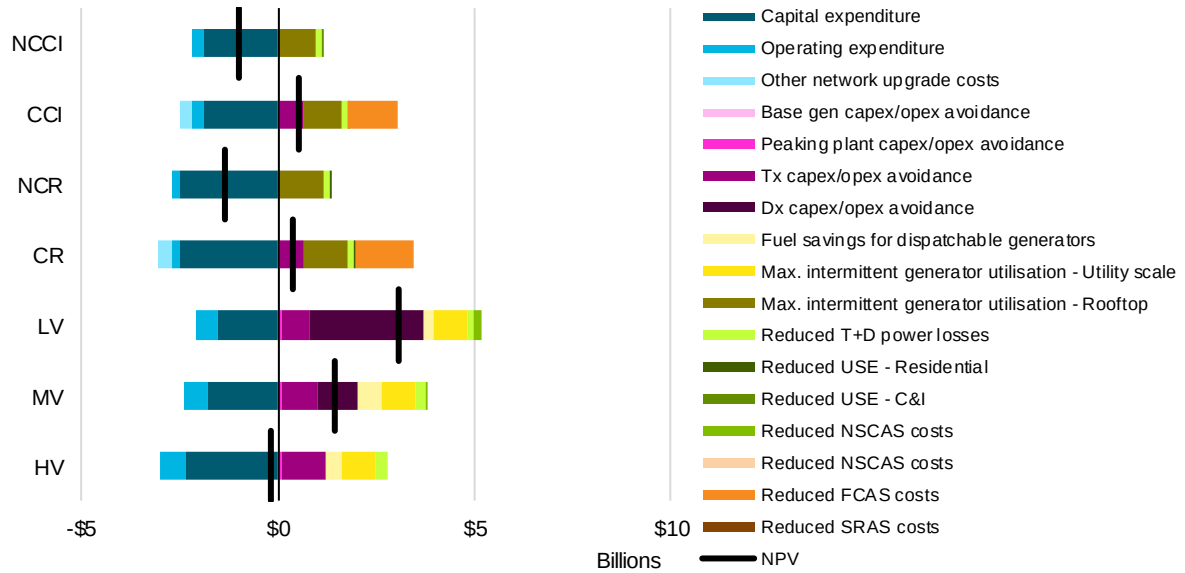
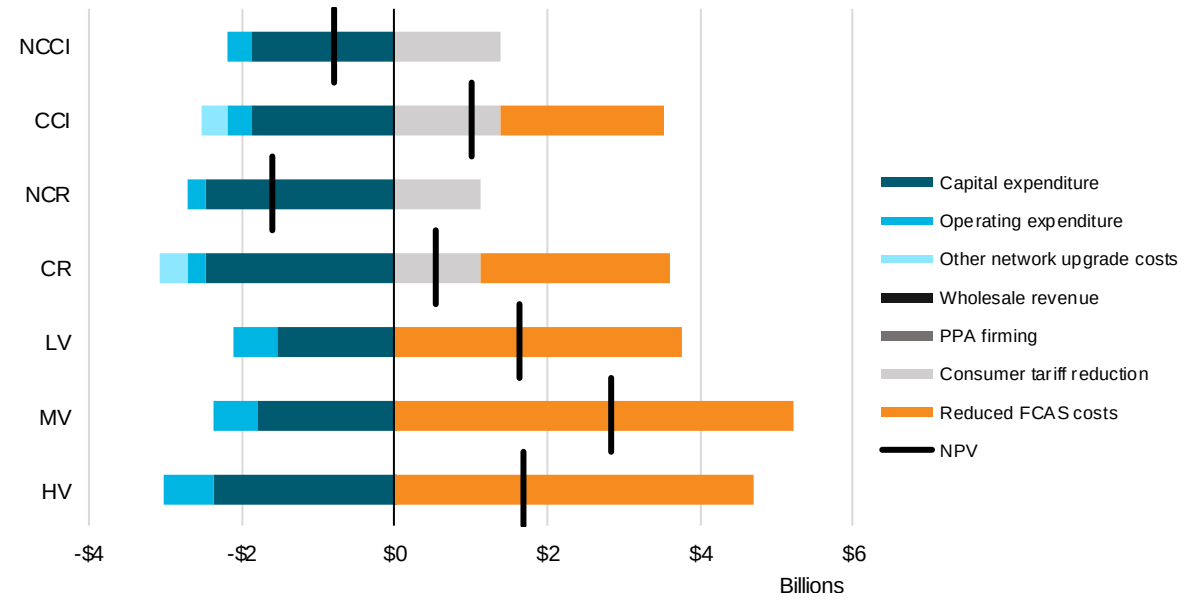


Figure 33 Medium scenario pathway commercial summary (2019 $billions, real)



7.5 High scenario

In the high scenario, there are major changes in Australia's energy market over the next 20 years. Economic and population growth are strong, with significant growth in total electricity consumption. There is greater deployment of storage batteries relative to the low and medium scenarios, which is reflected by higher total pathway costs as shown in Figure 34 and Table 36.

Figure 34 High scenario present value total costs by pathway (2019 $billions, real)

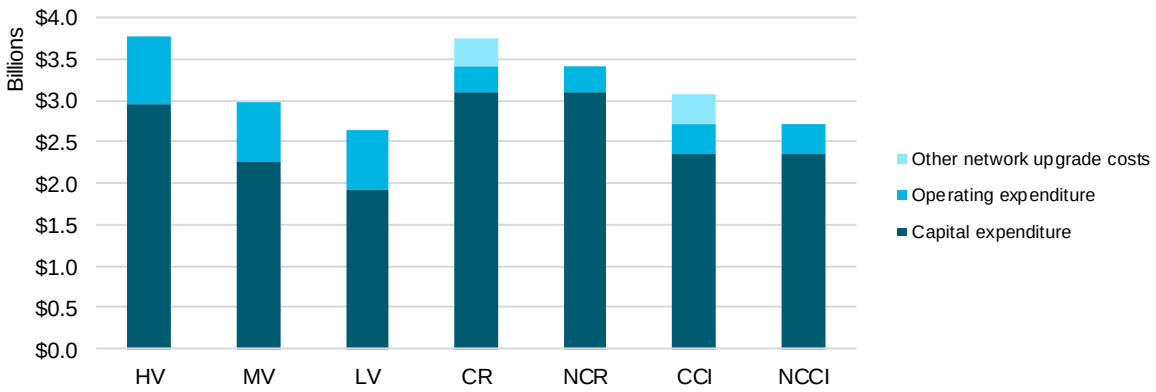


Table 36 Present value cost of pathways high scenario (2019 $billions, real)

Pathway	Capex	Opex	Other network upgrade costs	Total
HV	2.96	0.81	-	**3.77**
MV	2.25	0.72	-	**2.97**
LV	1.93	0.72	-	**2.65**
CR	3.10	0.31	0.34	**3.75**
NCR	3.10	0.31	-	**3.40**
CCI	2.34	0.38	0.34	**3.06**
NCCI	2.34	0.38	-	**2.72**

7.5.1 High scenario pathway system benefits

The system benefits estimated to be generated by each pathway in the high scenario are generally greater further up the supply chain (see Figure 35). The value realised for reduced T&D power losses reduces down the supply chain.

The analysis shows that not all benefits are able to be provided by every BESS deployment pathway and the fewest potential benefits are available from the non-controlled BESS. Controlled BESS have the potential to provide significant value in FCAS savings, accounting for up to half of the potential benefit of each of these pathways.

Grid BESS are able to maximise the use of intermittent utility scale generation. Garage BESS are able to maximise the use of intermittent rooftop solar generation at significantly higher values.

Distribution capex is only able to be provided by the grid batteries lower than HV, i.e. MV and LV.

The grid BESS pathways are able to provide peaking plant capex avoidance, reflective of the forecast increase in VRE. These BESS pathways are also able to provide transmission network capex deferral and fuel savings for dispatchable generators. C&I BESS are also able to provide fuel savings, but the impact is negligible.

Under this scenario all the controlled BESS pathways can provide base generation capex deferral because of the forecast increase in peak demand.

The overall value of reduction of USE is low in this scenario and is provided at similar levels by all pathways except for LV, which is significantly higher and HV which provides none of this value.

Figure 35 High scenario present value total potential system benefits by pathway (2019 $billions, real)

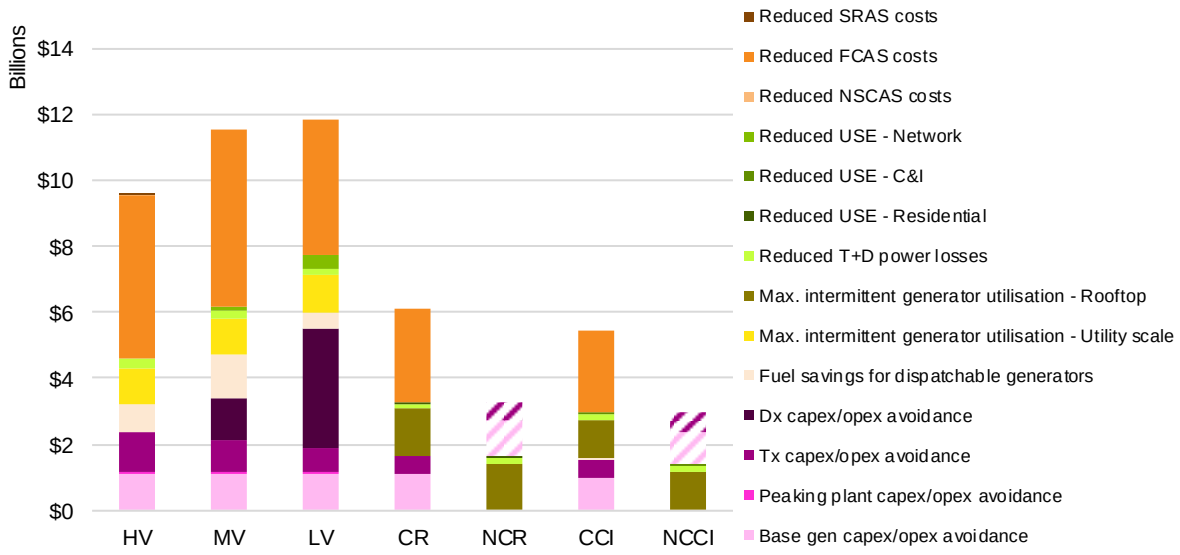


Table 37 Total potential system benefits of pathways high scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	1.08	1.08	1.07	1.07	-	0.96	-
Peaking plant capex/opex avoidance	0.09	0.09	0.09	-	-	-	-
Tx capex/opex avoidance	1.17	0.93	0.75	0.58	-	0.58	-
Dx capex/opex avoidance	-	1.30	3.59	-	-	-	-
Fuel savings for dispatchable generators	0.86	1.29	0.51	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	1.11	1.11	1.11	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	1.41	1.41	1.18	1.18
Reduced T+D power losses	0.32	0.26	0.21	0.16	0.16	0.16	0.16
Reduced USE - Residential	-	-	-	0.07	0.07	-	-
Reduced USE - C&I	-	-	-	-	-	0.05	0.05
Reduced USE - Network	-	0.11	0.41	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	4.93	5.36	4.11	2.81	-	2.49	-
Reduced SRAS costs	0.00	-	-	-	-	-	-

When the ability to access these values stream simultaneously is considered, the high scenario significantly scales back the HV, MV and LV pathway benefits as FCAS benefits are only able to be partially realised or not realised at all. All other value streams have remained approximately constant in the high scenario. The FCAS savings in the controlled garage pathways lead to stacked benefits being comparable with the upstream pathways.

Figure 36 High scenario stacked system benefits summary (2019 $billions, real)

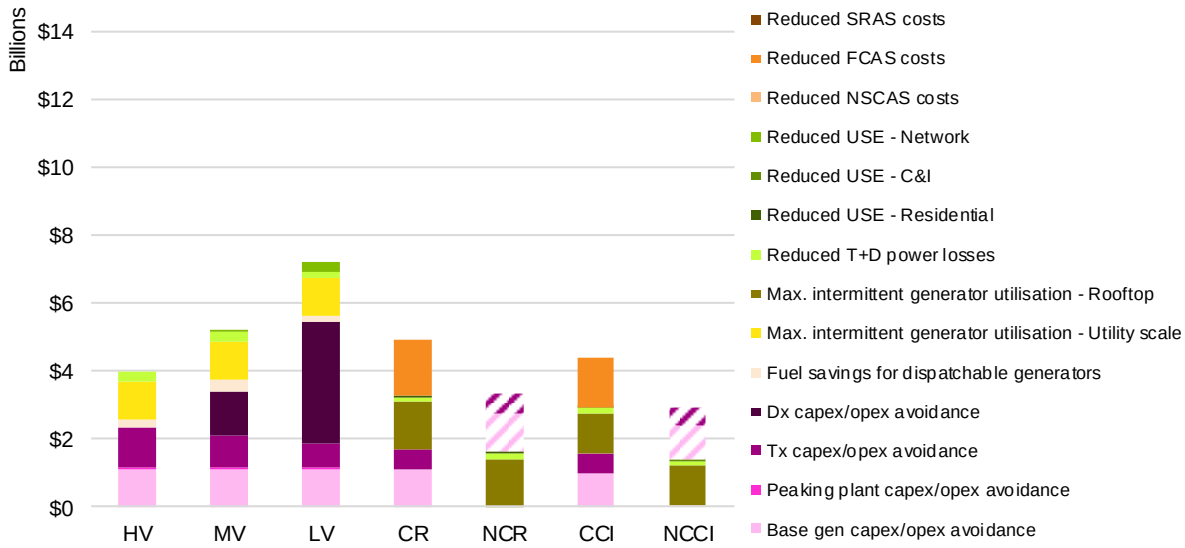


Table 38 High scenario stacked system benefits by pathway (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	1.08	1.08	1.07	1.07	-	0.96	-
Peaking plant capex/opex avoidance	0.05	0.05	0.05	-	-	-	-
Tx capex/opex avoidance	1.17	0.93	0.75	0.58	-	0.58	-
Dx capex/opex avoidance	-	1.30	3.59	-	-	-	-
Fuel savings for dispatchable generators	0.26	0.39	0.15	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	1.11	1.11	1.11	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	1.41	1.41	1.18	1.18
Reduced T+D power losses	0.32	0.26	0.21	0.16	0.16	0.16	0.16
Reduced USE - Residential	-	-	-	0.04	0.07	-	-
Reduced USE - C&I	-	-	-	-	-	0.03	0.05
Reduced USE - Network	-	0.06	0.24	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	-	-	-	1.66	-	1.47	-
Reduced SRAS costs	-	-	-	-	-	-	-
Total	**3.99**	**5.18**	**7.17**	**4.92**	**1.65**	**4.39**	**1.39**

7.5.2 High scenario pathway commercial benefits

The commercial benefits estimated to be generated by each pathway in the high scenario are dominated by FCAS savings, as presented in Figure 37. Consumer tariff reductions add to the commercial benefits for the garage pathways, however these are greatly outweighed by FCAS savings. The MV pathway returns the greatest present value benefit of approximately $5.4 billion followed by the HV pathway with $4.9 billion. PPA firming and wholesale revenue benefits are negligible.

Figure 37 High scenario present value total commercial benefits by pathway (2019 $billions, real)

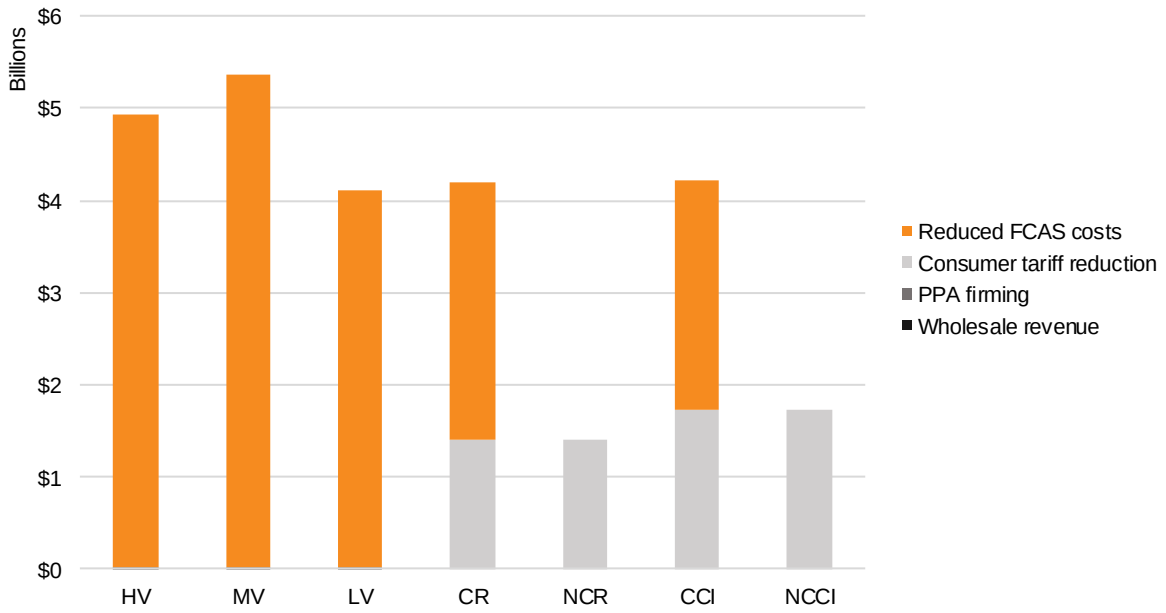


Table 39 Commercial benefits of pathways, high scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Wholesale revenue	0.01	0.01	0.01	-	-	-	-
PPA firming	-	-	-	-	-	-	-
Consumer tariff reduction	-	-	-	1.40	1.40	1.72	1.72
Reduced FCAS costs	4.93	5.36	4.11	2.81	-	2.49	-
Total	**4.94**	**5.38**	**4.12**	**4.21**	**1.40**	**4.21**	**1.72**

7.5.3 High scenario pathway NPVs

The MV and LV pathways perform best in terms of stacked system value in the high scenario, returning present value benefits of $2.2 billion and $4.5 billion respectively, as shown in Table 40 and Figure 38. The garage pathways perform poorly in comparison to upstream pathways with costs outweighing benefits in the non-controlled cases. Both non-controlled garage pathways have negative system returns, primarily due to the lack of FCAS benefits which are realised in the controlled pathways.

Commercial NPVs are positive for all pathways other than the non-controlled garage pathways, as presented in Figure 39. The grid pathways realise major FCAS benefits, resulting in an NPV of approximately $2.4 billion for LV. The non-controlled NCR pathway and NCCI pathway return negative NPVs as only consumer tariff reduction benefits are realised.

Table 40 High scenario pathway NPVs (2019 $billions, real)

Pathway	Total potential system benefits	Stacked system benefits	Commercial
HV	5.78	0.22	1.17
MV	8.55	2.21	2.40
LV	9.20	4.53	1.47
CR	2.36	1.18	0.46
NCR	(1.76)	(1.76)	(2.01)
CCI	2.36	1.32	1.15
NCCI	(1.33)	(1.33)	(1.00)

Figure 38 High scenario stacked system benefit pathway summary (2019 $billions, real)

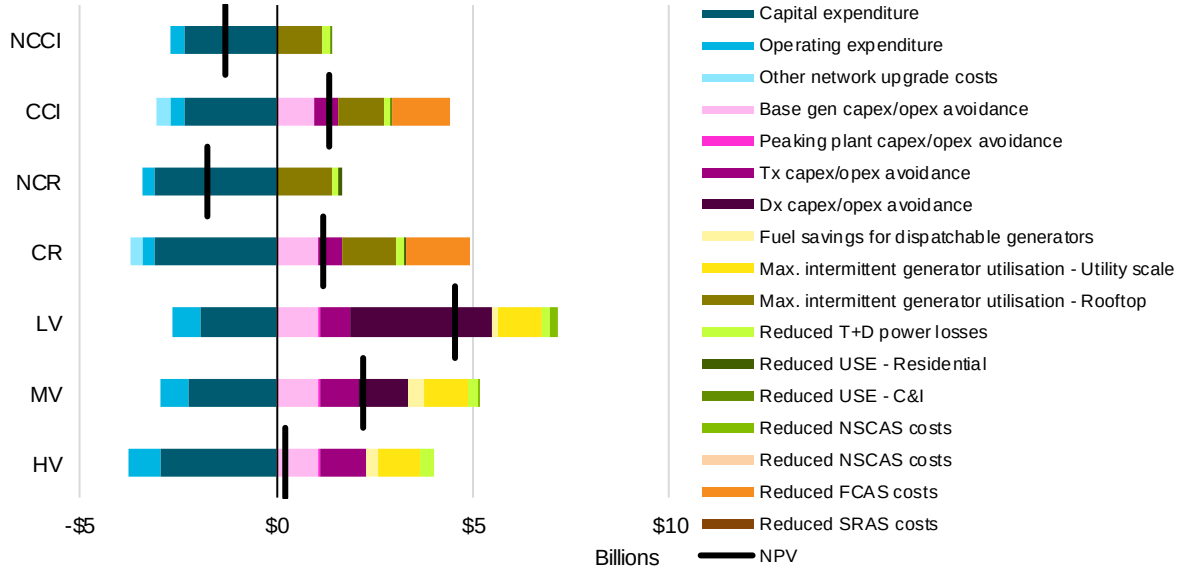
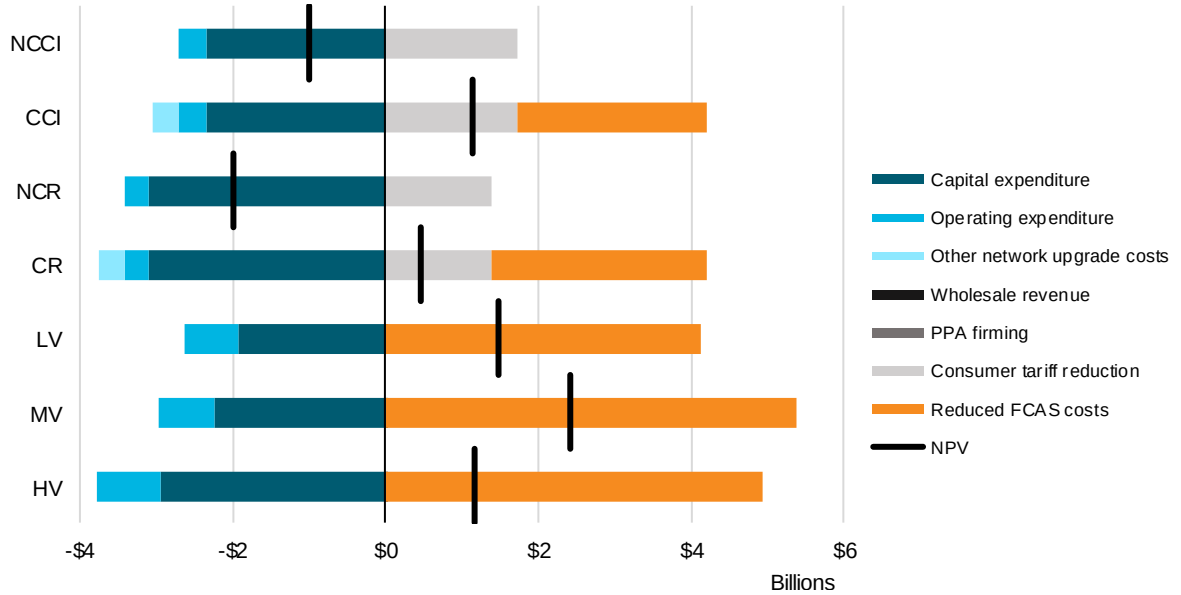


Figure 39 High scenario pathway commercial summary (2019 $billions, real)



7.6 Rapid transformation scenario

In the rapid transformation scenario, the changes in Australia's energy market over the next 20 years are profound. Peak demand and total electricity consumption are high and there is major technology advancement, driving strong demand side participation and EV adoption. More than three quarters of total electricity generation is from renewable sources, spurring significant deployment of storage batteries. Total pathway costs for the rapid transformation scenario are the same as for the high scenario, as shown in Figure 40 and Table 41.

Figure 40 Rapid transformation scenario present value total costs by pathway (2019 $billions, real)

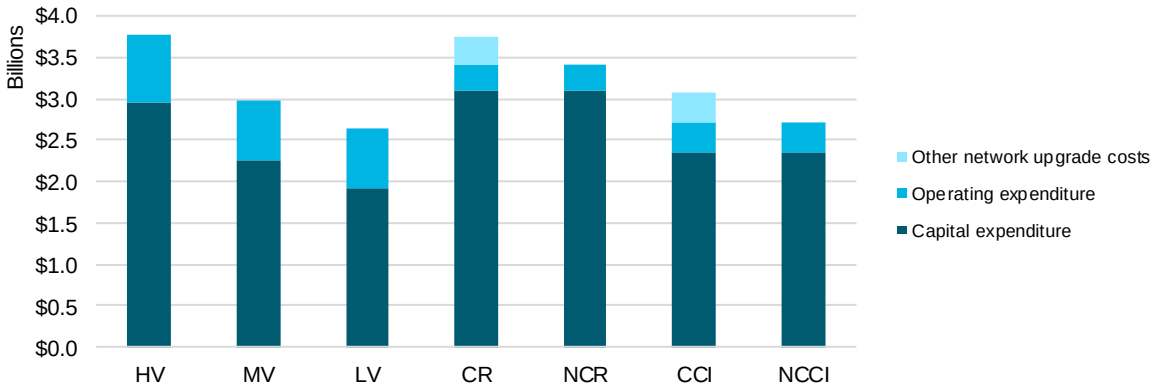


Table 41 Present value cost of pathways rapid transformation scenario (2019 $billions, real)

Pathway	Capex	Opex	Other network upgrade costs	Total
HV	2.96	0.81	-	**3.77**
MV	2.25	0.72	-	**2.97**
LV	1.93	0.72	-	**2.65**
CR	3.10	0.31	0.34	**3.75**
NCR	3.10	0.31	-	**3.40**
CCI	2.34	0.38	0.34	**3.06**
NCCI	2.34	0.38	-	**2.72**

7.6.1 Rapid transformation scenario pathway system benefits

The system benefits estimated to be generated by each pathway in the rapid transformation scenario are generally greater further up the supply chain, as shown in Figure 41 and Table 42. The value realised for reduced T&D power losses reduces down the supply chain with LV realising the greatest amount of distribution benefit of all pathways.

The analysis shows that not all benefits are able to be provided by every BESS deployment pathway and the fewest potential benefits are available from the non-controlled BESS. Controlled BESS have the potential to provide significant value in FCAS savings, accounting for up to half of the potential benefit of each of these pathways.

Grid BESS are able to maximise the use of intermittent utility scale generation. Garage BESS can maximise the use of intermittent rooftop solar generation at lower values.

Distribution capex avoidance is only able to be provided by the grid batteries lower than HV, i.e. MV and LV.

The grid BESS pathways are able to provide peaking plant capex avoidance, reflective of the forecast increase in VRE. These BESS pathways are also able to provide transmission network capex deferral

and fuel savings for dispatchable generators. C&I BESS are also able to provide fuel savings, but the impact is negligible.

Under this scenario all the controlled BESS pathways can provide significant base generation capex deferral because of the forecast increase in peak demand.

The overall value of reduction of USE is low in this scenario and is provided at similar levels by all pathways except for LV, which is significantly higher and HV which provides none of this value.

Figure 41 Rapid transformation scenario present value total potential system benefits by pathway (2019 $billions, real)

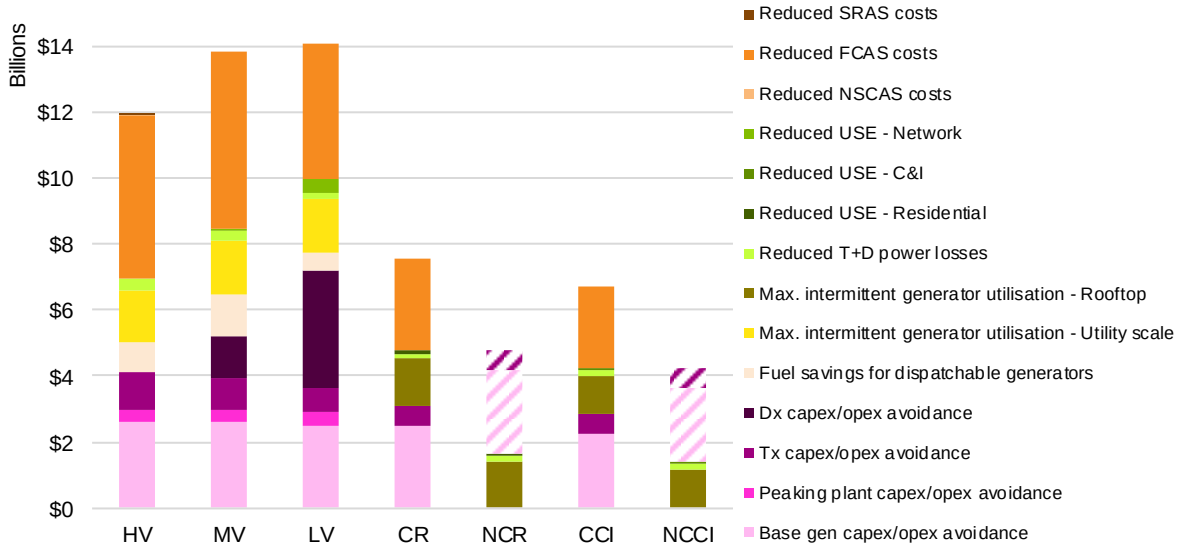


Table 42 Total potential system benefits of pathways, rapid transformation scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	2.58	2.58	2.51	2.51	-	2.25	-
Peaking plant capex/opex avoidance	0.40	0.40	0.36	-	-	-	-
Tx capex/opex avoidance	1.17	0.93	0.75	0.58	-	0.58	-
Dx capex/opex avoidance	-	1.30	3.59	-	-	-	-
Fuel savings for dispatchable generators	0.86	1.29	0.51	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	1.61	1.61	1.61	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	1.41	1.41	1.18	1.18
Reduced T+D power losses	0.34	0.27	0.22	0.17	0.17	0.17	0.17
Reduced USE - Residential	-	-	-	0.07	0.07	-	-
Reduced USE - C&I	-	-	-	-	-	0.05	0.05
Reduced USE - Network	-	0.11	0.41	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	4.93	5.36	4.11	2.81	-	2.49	-
Reduced SRAS costs	0.00	-	-	-	-	-	-

Considering the ability of BESS to access these value streams simultaneously for the rapid transformation scenario scales back the HV, MV and LV pathway benefits as FCAS benefits are only able to be partially realised or not realised at all. Base generation expenditure avoidance is maximised in this scenario for all pathways except for the non-controlled garage pathways. The FCAS savings in the controlled garage pathways lead to staked benefits being comparable with the upstream pathways.

Figure 42 Rapid transformation scenario stacked system benefits summary (2019 $billions, real)

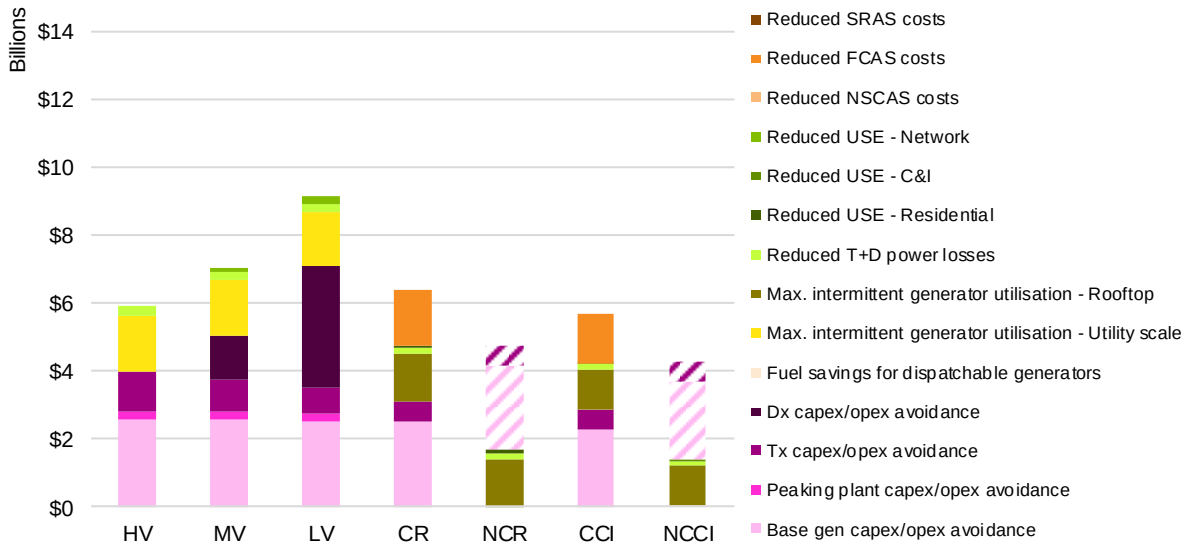


Table 43 Rapid transformation scenario stacked system benefits by pathway (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Base gen capex/opex avoidance	2.58	2.58	2.51	2.51	-	2.25	-
Peaking plant capex/opex avoidance	0.23	0.23	0.21	-	-	-	-
Tx capex/opex avoidance	1.17	0.93	0.75	0.58	-	0.58	-
Dx capex/opex avoidance	-	1.30	3.59	-	-	-	-
Fuel savings for dispatchable generators	-	-	-	-	-	0.00	0.00
Max. intermittent generator utilisation - Utility scale	1.61	1.61	1.61	-	-	-	-
Max. intermittent generator utilisation - Rooftop	-	-	-	1.41	1.41	1.18	1.18
Reduced T+D power losses	0.34	0.27	0.22	0.17	0.17	0.17	0.17
Reduced USE - Residential	-	-	-	0.04	0.07	-	-
Reduced USE - C&I	-	-	-	-	-	0.03	0.05
Reduced USE - Network	-	0.06	0.24	-	-	-	-
Reduced NSCAS costs	-	-	-	-	-	-	-
Reduced FCAS costs	-	-	-	1.66	-	1.47	-
Reduced SRAS costs	-	-	-	-	-	-	-
Total	**5.93**	**6.99**	**9.14**	**6.38**	**1.66**	**5.68**	**1.40**

7.6.2 Rapid transformation scenario pathway commercial benefits

Consistent with the other scenarios, the commercial present value benefits estimated to be generated by each pathway in the rapid transformation scenario are dominated by FCAS savings, as shown in Figure 43. Consumer tariff reductions add to the commercial benefits for the garage pathways, however these are greatly outweighed by FCAS savings. The MV pathway returns the greatest benefit of approximately $5.4 billion followed by the HV pathway with $4.9 billion. PPA firming and wholesale revenue benefits are negligible.

Figure 43 Rapid transformation scenario present value total user benefits by pathway (2019 $billions, real)

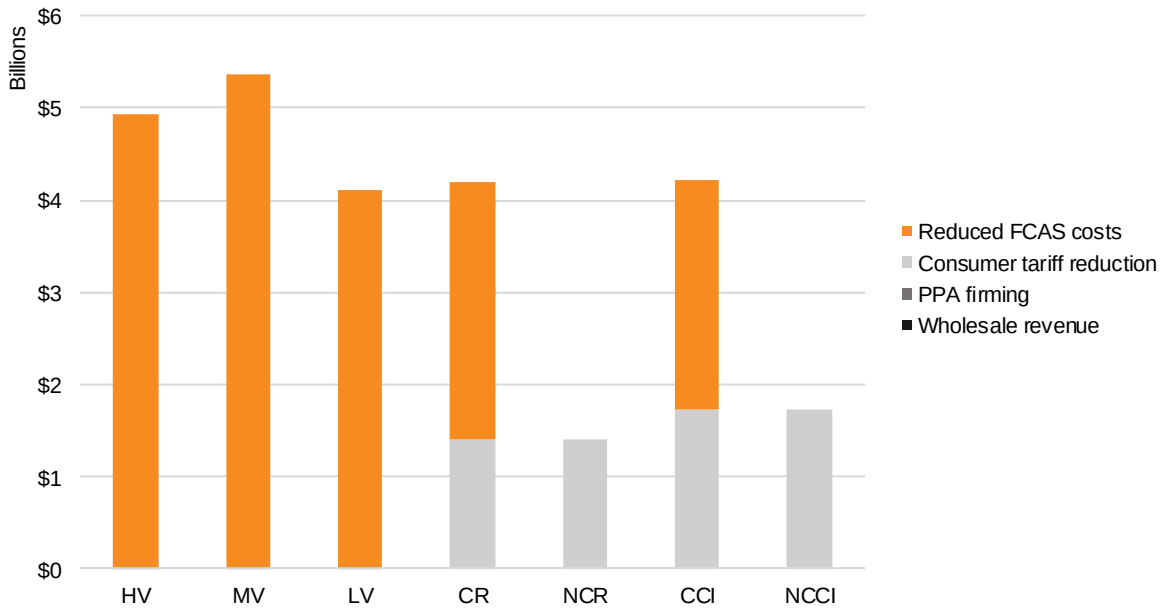


Table 44 Commercial benefits of pathways, rapid transformation scenario (2019 $billions, real)

Pathway	HV	MV	LV	CR	NCR	CCI	NCCI
Wholesale revenue	0.01	0.01	0.01	-	-	-	-
PPA firming	-	-	-	-	-	-	-
Consumer tariff reduction	-	-	-	1.40	1.40	1.72	1.72
Reduced FCAS costs	4.93	5.36	4.11	2.81	-	2.49	-
Total	**4.94**	**5.38**	**4.12**	**4.21**	**1.40**	**4.21**	**1.72**

7.6.3 Rapid transformation scenario pathway NPVs

Most pathways deliver greatest system value in the rapid transformation scenario. LV performs significantly better in this scenario than any other, driven primarily by the increased avoidance of future base generation expenditure, reduction in FCAS and avoidance of distribution expenditure. As in the other scenarios, the non-controlled residential and C&I pathways do not perform as well as the controlled pathways, as outlined in Table 45. Being non-controlled, the NCR and NCCI pathways do not contribute to the avoidance of future baseload generation, FCAS and network expenditure, which are major benefits of the controlled pathways.

Commercial NPVs are positive for all pathways other than the non-controlled garage pathways as presented in Table 45 and Figure 45. The HV pathways realise major FCAS benefits returning NPVs of between $2.4 billion and $1.2 billion. The non-controlled NCR pathway and NCCI pathway return negative NPVs as only consumer tariff reduction benefits are realised.

Table 45 Rapid transformation scenario pathway NPVs (2019 $billions, real)

Pathway	Total potential system benefits	Stacked system benefits	Commercial
HV	8.11	2.16	1.17
MV	10.88	4.02	2.40
LV	11.44	6.49	1.47
CR	3.82	2.63	0.46
NCR	(1.75)	(1.75)	(2.01)
CCI	3.66	2.62	1.15
NCCI	(1.32)	(1.32)	(1.00)

Figure 44 Rapid transformation scenario stacked system benefit pathway summary

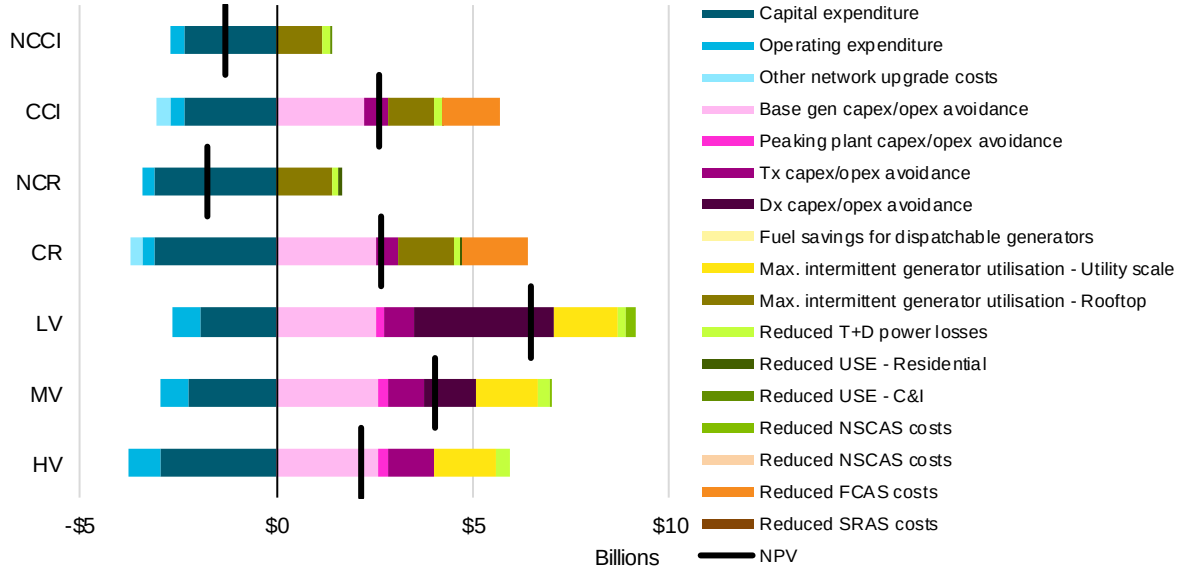
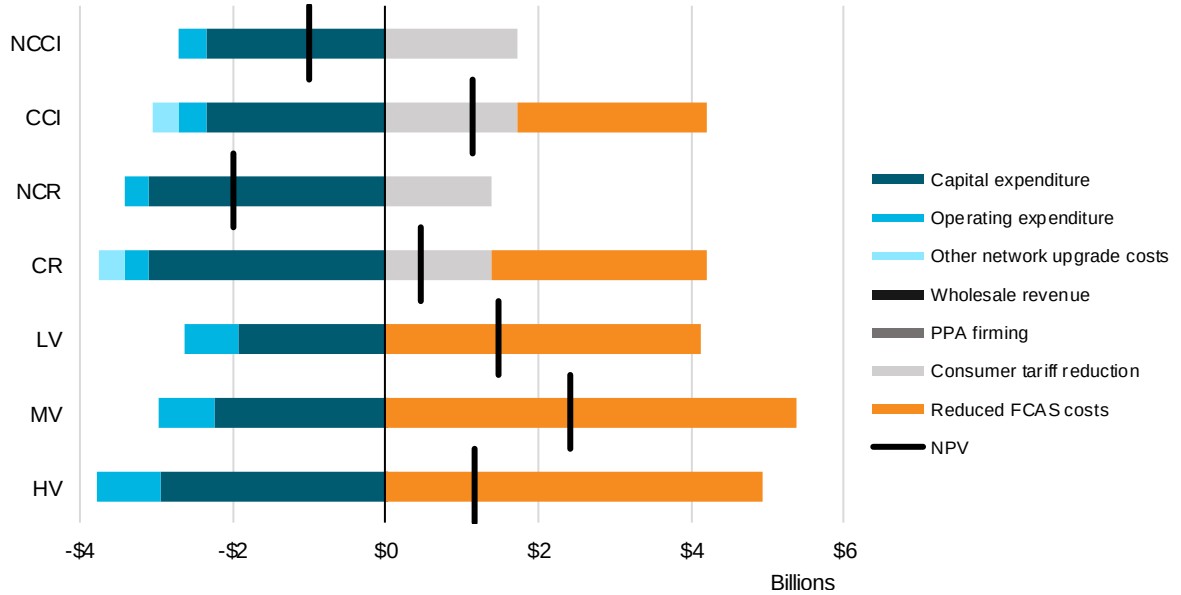


Figure 45 Rapid transformation scenario commercial pathway summary



7.7 Findings

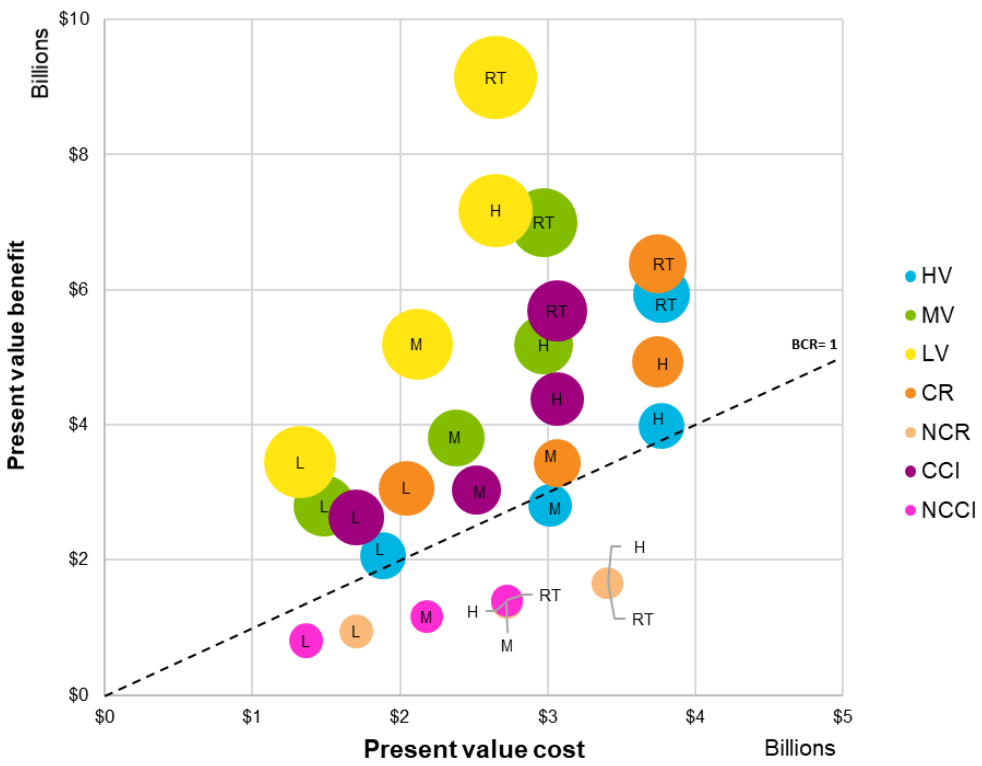
Our analysis of BESS deployment options at different connection points found:

1. There is a diversity of market and commercial benefits from BESS deployment
2. BESS on the low voltage network provide greatest benefit
3. Controlled BESS create additional value for the system and asset owners.

In general, pathways perform better the higher the level of electricity consumption. This is shown in Figure 46 and Figure 47 with pathway benefits plotted on the y-axis, costs on the x-axis and the size of each bubble reflecting benefit cost ratios. The ideal position is in the top left quadrant with high benefits and low costs.

Relative pathway performance is generally maintained across all scenarios for system benefits, as shown in Figure 46. The analysis shows that not all benefits are able to be provided by every BESS deployment pathway and the fewest potential benefits are available from the non-controlled BESS pathways.

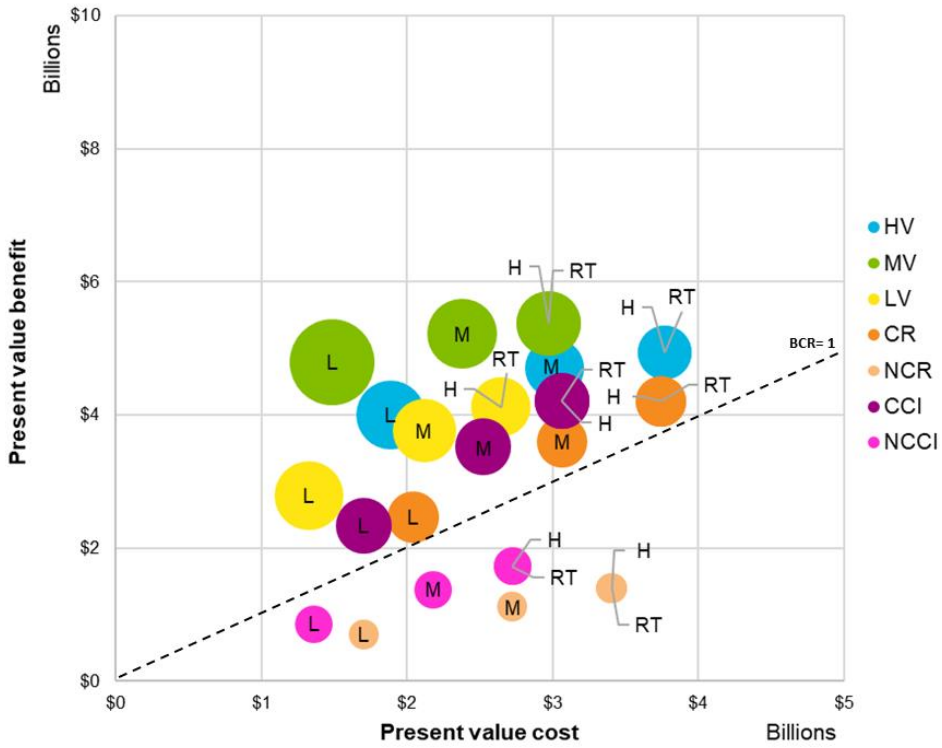
Figure 46 Pathway costs and stacked system benefits (2019 $billions, real)



As with system benefits, pathway performance is generally consistent across all scenarios for commercial benefits, as shown in Figure 47. Three benefits have been realised: consumer tariff reductions for the garage pathways, wholesale revenue for grid pathways, and FCAS benefits for all pathways except for non-controlled pathways. Wholesale revenue is smaller than the potential FCAS revenues but is a more bankable return.

MV performs the best of all pathways and scenarios. This is reflective of the FCAS benefits recognised under this pathway. As with the system benefits, the garage pathways are outperformed by the grid pathways for commercial benefits.

Figure 47 Pathway costs and commercial benefits (2019 $billions, real)



Finding 1: There is a diversity of market and commercial benefits from BESS deployment

Grid BESS provide different value streams than garage BESS, across all deployment pathways and electricity market scenarios, as outlined in Figure 48.

Grid and garage BESS provide some of the same value streams, including deferring base generation plant and transmission augex, reducing T&D power losses and reducing USE. Grid and garage BESS are likely to compete with each other to provide the services that realise these values. However, they each provide several value stream benefits for which they would not need to compete.

In particular, grid BESS maximise the utilisation of utility scale wind and solar, whereas garage BESS maximise the utilisation of roof-top solar, and neither are able to compete with each other for these values. Similarly, grid BESS can provide fuel savings for gas peaking plant whereas garage BESS can provide fuel savings for diesel generators on commercial and industrial sites.

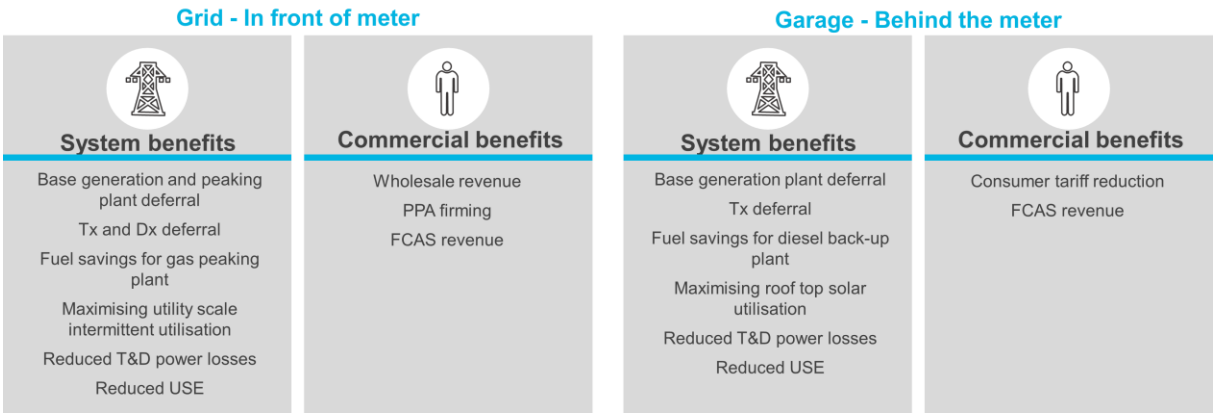
Grid BESS pathways can provide peaking plant capex avoidance, reflective of the forecast increase in VRE. These BESS pathways are also able to provide transmission network capex deferral and fuel savings for dispatchable generators. While C&I BESS can provide fuel savings, these impacts are negligible.

Grid BESS are able to maximise the use of intermittent utility scale generation. Garage BESS can maximise the use of intermittent rooftop solar generation. The values are similar magnitude, but garage BESS provide slightly higher value in the low scenario, and significantly higher value in the high scenario. In the rapid transformation scenario, grid BESS provide slightly greater value because the penetration of DER is considered the same as the high scenario, but the penetration of utility scale renewables increases.

Grid BESS can defer distribution augex but because the penetration of garage batteries remains low for all deployment pathways and electricity market scenarios, they are unable to provide any meaningful benefit in deferring distribution augex.

In terms of commercial returns, controlled garage BESS can provide consumer tariff reductions that are not directly realised by grid BESS.

Figure 48 Grid and garage BESS benefits



Finding 2: BESS on the low voltage network provide greatest system benefits

LV BESS provide the greatest overall system benefits, as shown by their location close to the top left corner of Figure 46. The analysis highlights that this difference in value is largely driven by the ability of LV BESS to defer distribution augex. As electricity consumption increases, the LV pathway can provide significant FCAS, distribution deferral and base generation deferral benefits.

Distribution deferral is only able to be provided by grid batteries which are not on the high voltage network, i.e. MV and LV. The overall value of reduction of USE is low in all scenarios and is provided at similar levels by all pathways except for LV, which is significantly higher, and HV which provides none of this value.

This system benefit does not directly align with the commercial benefit; MV BESS provide the greatest commercial value as shown in Figure 47. This is a possible cause of the limited investment in LV BESS in the NEM to date.

Finding 3: Controlled BESS creates value for the system and asset owners

Controlled garage BESS provide significantly greater system benefits and commercial returns than non-controlled garage BESS, as shown by their location further from the bottom right corner of Figure 46 and Figure 47. The benefits of both the commercial and industrial and residential pathways are largely dependent on their controlled nature. Non-controlled storage batteries are unable to reduce FCAS costs or transmission network expenditure. As a result, the CR and CCI pathways outperform NCR and NCCI pathways across all scenarios.

Controlled BESS have the potential to provide significant value in FCAS savings under each scenario, accounting for more than half of the potential benefit of each of the pathways. Under the scenarios with increasing peak demand, only the controlled BESS pathways can provide base generation capex deferral. Residential pathways and commercial and industrial pathways yield very similar system benefits across all scenarios. Slightly greater FCAS benefits are available in the CR pathway.

8.0 Policy and system implications

Significant change is occurring in the NEM as many of Australia's coal fired baseload generators are retired. Replacement generation is largely coming from renewable sources of energy; and, alongside this generation renewal, new storage and demand management technologies are being connected into the electricity network. In short, the NEM is undergoing a profound shift in how electricity is produced and dispatched, where energy resources are located, and how consumers interact with the system. The future electricity system will be more complex and diverse.

Against this transformative backdrop, this study examined the economic value of new battery system deployments in front of and garage. The assessment highlighted which forms of battery deployments have the potential to deliver the greatest systemic value, factoring in their costs and different market conditions.

The deployment of BESS, especially when it starts to gather pace, raises important implications for policymakers, network owners, market bodies and asset owners. One of the central issues is how best the technology can be integrated within the network, and what barriers could prevent BESS from successfully supporting the electricity network as it continues to grow and evolve.

Such issues need to be considered amid a range of challenges facing the energy industry and energy policy in Australia. This includes concerns about high electricity prices and system security, the interplay of climate change and renewable energy policies at a federal and state level, and attendant uncertainties on long term policy settings which may be deterring some forms of generation investment.

This section discusses key implications of greater battery energy storage penetration at the small and utility scale. It looks at, within the context of the BESS deployment pathways and scenarios examined, the network challenges that different forms of BESS can address and how the value of deployment to asset owners and system users can be optimised.

8.1 A future energy system with significant battery storage

The deployment pathways examined include BESS connected at different points of the network, with different services and available value, as well as prevailing technology and cost trends. These pathways are overlaid on four distinct scenarios about how electricity markets might change over the coming decades, determining different levels of BESS penetration over the next 20 years, consistent with expectations of investment. The scenarios, moving from low to high, reflect greater levels of grid demand, more rapid penetration of DER, more new technology adoption such as EVs, and greater improvements in energy efficiency. While the scenarios differ in terms of their form and trajectory, they each portray a future where BESS penetration in the electricity system is substantially greater than today.

Even under less transformational changes, it is difficult to imagine that Australia's future energy system will not feature greater levels of energy storage in various forms such as utility and domestic scale BESS and pumped hydro (e.g. Snowy 2.0).

8.1.1 The value of BESS deployments in front of meter

The analysis highlighted that different deployments of in front of and behind the meter BESS have the potential to deliver markedly different value outcomes to the system and asset owners.

At a general level, grid BESS deployments grid (HV, MV and LV pathways) are able to provide a wide range of market and network services by virtue of their large scale and their upstream installation on either the transmission or distribution networks. These key services include:

- supporting intermittent utility scale generation like commercial solar and wind farms (VRE) which require that output variation be firmed by other energy storage technology like BESS
- deferring the need for network augmentation by supplying power at a more localised level
- reducing the requirement for new solar PV and wind generators by shifting excess generation when it occurs to meet demand at a later time

- reducing the need for new peaking plant by better managing peak demand on the network through load shifting and, in doing so, avoiding transmission losses by reducing peak power flows and optimising the utilisation of the network
- reducing the fuel costs of gas peaking plant for the network
- lowering the cost of frequency control services (FCAS) within the NEM.

The analysis indicates that the value of these benefits exceeds the whole-of-life costs of the front-of-meter BESS deployments.

For asset owners, the decision to invest in grid BESS will hinge on the commercial returns they expect to receive. The key revenue stream from energy storage like BESS is energy arbitrage, i.e. buying energy to charge when prices are low, and discharging energy to sell when prices are high.

The ability to secure revenues from participating in FCAS markets is also important for project commerciality. These revenues streams, under current market expectations and rules, are particularly uncertain. There can be difficulties in banking projects which are heavily dependent on FCAS payments.

8.1.2 The value of BESS deployments behind the meter

The value outcomes for garage BESS deployments are different to the grid deployments. These assets are installed on premises, either commercial facilities or households, behind the meter. They are much smaller units, sized to meet the localised energy storage, generation and load requirements of their respective business or residence.

Their key market and system benefits include:

- maximising the utilisation of intermittent rooftop solar generation
- deferring the need for augmentation of transmission networks by reducing peak demand at a localised level
- reducing the requirement for new utility scale generation by load shifting and reducing power losses on the network
- reducing the fuel costs of diesel back-up generation for C&I customers.

For the owner businesses or households, the largest driver of investment in a BESS is derived from the ability to reduce power purchases from the grid, or minimising consumer tariffs. This can occur through shifting tariff consumption from higher to lower cost periods, or relatedly, from storing energy from the peak generation of rooftop solar PV systems for later use.

An important aspect is that these smaller systems can either respond to market signals or operate independently of the network. Those that can respond to market signals can function in a coordinated manner, potentially through third-party operators, or operate in an independent standalone manner. Much of the potential value outcome depends on the capacity of the BESS to respond to market signals or to orchestrate the many smaller BESS into a much larger virtual system. Where garage BESS can be controlled, the value outcomes at a network and commercial level are likely to be positive and outweigh the cost of deployment.

A summary of the value benefits across BESS deployments is provided in Table 46.

Table 46 BESS pathway considerations summary

Market issues	Grid — front of meter			Garage — behind the meter	
	HV	MV	LV	Controlled (CR and **CCI**)	Non-controlled (NCR and **NCCI**)
Market benefits	• Maximise the use of intermittent utility scale generation • Base and peaking plant capex avoidance • Fuel savings for dispatchable generators • Reduced FCAS costs	• Maximise the use of intermittent utility scale generation • Base and peaking plant capex avoidance • Fuel savings for dispatchable generators • Reduced FCAS costs	• Maximise the use of intermittent utility scale generation • Base and peaking plant capex avoidance • Fuel savings for dispatchable generators • Reduced FCAS costs	• Base plant capex avoidance • Fuel savings for dispatchable generators • Maximise the use of intermittent rooftop solar generation • Reduced FCAS costs	• Fuel savings for dispatchable generators • Maximise the use of intermittent rooftop solar generation
Network benefits	• Transmission capex deferral • Reduced T&D power losses	• Transmission capex deferral • Distribution capex deferral • Reduced T&D power losses	• Transmission capex deferral • Distribution capex deferral • Reduced T&D power losses	• Transmission capex deferral • Reduced T&D power losses	• Reduced T&D power losses
Consumer benefits		• Reduced USE	• Reduced USE	• Reduced USE	• Reduced USE
Asset owner benefits	• Wholesale revenue	• Wholesale revenue	• Wholesale revenue	• Consumer tariff reduction	• Consumer tariff reduction
System benefits value	• Positive returns except in high scenario	• Positive returns in all scenarios	• Positive returns in all scenarios	• Positive returns in all scenarios	• Negative returns in all scenarios
Commercial value	• Positive returns in all scenarios, heavily influenced by FCAS	• Positive returns in all scenarios, heavily influenced by FCAS	• Positive returns in all scenarios, heavily influenced by FCAS	• Positive returns in all scenarios, influenced by FCAS	• Negative returns in all scenarios
Implications	• Likely to increase VRE uptake through maximising generation and returns • Has limited ability to reduce USE because transmission networks are highly reliable • FCAS is not a highly bankable revenue stream and may be difficult to finance	• Likely to increase VRE uptake through maximising generation and returns • Although ability to reduce USE is lower than LV, the reduced USE will be seen by more consumers and likely be more equitable • FCAS is not a highly bankable revenue stream and may be difficult to finance	• Likely to increase VRE uptake through maximising generation and returns • Reduced USE is highly localised where BESS are installed and may create diverse experiences for consumers in terms of network performance • FCAS is not a highly bankable revenue stream and may be difficult to finance	• Likely to increase uptake of rooftop solar in a managed way • Consumers investment into an aggregated BESS or VPP may stop realising benefits if they leave the program or products are not clear about the benefits • Although returns are not likely to be bankable, private ownership and small system sizes mean that finance is likely to be debt based	• Likely to increase uptake of rooftop solar and may cause further dynamic issues and reverse flows • Consumers' naive investment into non-controlled BESS may result in them not getting the benefits they intended • Although returns are not likely to be bankable, private ownership and small system sizes mean that finance is likely to be debt based
Barriers and impediments	• Lack of access to commercial return for market and network benefits • Access to finance	• Islanding technology required to reduce USE • Access to finance	• Grid-forming inverters required to reduce USE on radial networks • BESS need to be load matched or demand response required to load match to reduce USE when islanded • Access to finance	• Islanding technology required to reduce USE • Customers are subject to a retail rate which does not always reflect the actual network costs and tariff arbitrage may have perverse outcomes including cross-subsidisation	• Islanding technology required to reduce USE • AEMO and DNSPs require visibility of BESS when deployed at scale
Broader policy or industry considerations	• Access to commercial return or avoided costs for network support required to incentivise investment	• Access to commercial return or avoided costs for network support required to incentivise investment • Understanding of the technical limitations to reduce USE and the potential opportunities to do so under the existing regulatory framework	• Access to commercial return or avoided costs for network support required to incentivise investment • Understanding of the technical limitations to reduce USE and the potential opportunities to do so under the existing regulatory framework	• Understand if retail offerings encourage BESS behaviour that increases costs for others in the long term	• Determine if non-controlled batteries operate in a predictable fashion at high deployment

8.2 Key policy and industry implications

The analysis undertaken as part of this study highlights that there are network and market benefits which are potentially available from grid BESS deployments that are not available from garage deployments, and vice versa. It is also unlikely that the overall quantum of benefits from utility scale battery systems installed on the grid can be achieved by garage-scale batteries at corresponding levels of deployment. As such, it is likely that a portfolio of configurations is required to maximise the economic value of future BESS deployment, irrespective of the ultimate state of the energy market over the next two decades.

There are some key areas for policy and industry attention which would support the ability of BESS, in various scales and forms, to play a positive role in Australia's energy system, including:

- Optimising value for the network
- Reducing the uncertainty of investment
- Realising equitable network performance
- Promoting better system reliability and security
- Ensuring the value of behind the meter BESS are realised
- Aligning tariff reform and social equity.

8.2.1 Optimising value for the network through a portfolio approach

Recognising the respective value opportunities that are available, as highlighted in this study, investors have been actively pursuing both utility-scale and residential battery storage projects. Indeed, several utility-scale batteries have now been installed in the NEM, some with ARENA support. In coming years, customers will increasingly meet their energy needs by drawing on energy stored in batteries, typically as a complement to large scale VRE or rooftop solar PV systems. This uptake is also being driven by various state government facilitation programs.

While this commercial activity shows that investors are likely to deliver a range of battery solutions into the market, these outcomes may not necessarily be optimal from a whole of system perspective. The rapid growth of DER like rooftop solar PV over recent years highlights how investments can outpace the capacity of system operators and relevant market frameworks to well-manage their integration.

In this regard, there is considerable merit in encouraging an appropriate balance of both utility-scale and smaller battery systems installed in the NEM. A portfolio-based approach would recognise the role which different scale BESS can play in the power systems.

8.2.2 Reducing the uncertainty of investment

A particular challenge for optimising the extent to which BESS, especially at utility scale, can provide innovative and cost effective system support services concerns the bankability of relevant ancillary service revenues. That is, how can the network security benefits of batteries be commercialised so there are suitable incentives to invest and innovate. Addressing constraints on the ability of BESS projects to access finance on the right terms has the potential to encourage greater deployment of grid scale batteries.

Constraints on accessing commercial returns for providing market and network benefits are a major impediment for grid-scale BESS systems, as underscored by the direct facilitation needed for most of these projects to date. Moving beyond a situation of governments underwriting projects in some form will require greater visibility and surety on long term revenue streams, particularly system support services. Relevant network services and their revenue streams are subject to high levels of policy risk. Technical rule changes, now or in the future, can significantly impact the capacity of BESS projects to secure revenues. This risk appears to be reducing the confidence of lenders to finance battery storage projects.

Further, certainty around the approach to apply network use of service charges for BESS at the transmission and distribution level without case-by-case negotiations with DNSPs and TNSPs will inform the likelihood of BESS being deployed at these levels. This will better inform developers,

investors NSPs and market operators about the likely issues and values that the BESS portfolio will provide.

Promoting greater policy stability in the energy security space, especially in terms of principles and future directions, would help address this constraint. Simply, financiers require greater surety that well-set rules are unlikely to change, with the risk that ancillary service revenues available to BESS projects evaporate. Consultation with finance providers and industry could help identify the greatest uncertainties or information gaps, and what measures could provide greater confidence on the bankability of system support revenues.

It is important to note that the battery system deployments examined increase year-on-year over a 20-year period. These adoption pathways recognise the inherent installation limits for the storage assets, changes in relative prices due to technological advancement, and requirements for generation and storage services. This deployment growth in later years will depend on realising the inherent value of investments in earlier years. Simply, a strong deployment trajectory will not be sustained if the investments underperform or face undue policy and regulatory uncertainties.

8.2.3 Realising network performance improvement

The analysis shows that utility scale BESS at LV level have the potential to significantly improve network performance, with MV BESS able to provide improvements to a lesser degree. At a high level, this improved network performance is likely to encourage DNSPs to invest in or procure services from LV BESS and result in the greatest improvement in network performance.

In practice benefits such as the reduced USE provided by LV BESS are likely to be localised to where BESS are installed and may create diverse experiences for consumers in terms of network performance. Opportunity exists for this varied performance to be leveraged to equalise areas of existing poor performance.

In order to realise the benefits, it will be necessary to test and resolve the technical limitations of BESS to improve network performance. For USE, this includes trialling the use of grid-forming inverters on radial networks and investigating the need to load match BESS to demand to reduce USE when islanded.

8.2.4 Promoting better system reliability and security

There has been considerable attention by Australian governments on challenges to the ongoing reliability and security of Australia's electricity network presented by the rapid uptake of VRE. As baseload coal fired generators have started to retire, a range of market support services have become scarcer. This includes services to maintain physical inertia, system strength and voltage control.

An inherent feature of VRE is that their power output is highly sensitive to weather conditions (e.g. cloud cover, storm fronts and wind speeds) and can change quickly. This can create challenges for managing electricity flows within and between NEM regions and increases requirements for frequency control services [45]. These issues, which are part of a long term structural trend towards greater VRE in the NEM, may well intensify and need to be managed carefully.

As indicated by the analysis, BESS has considerable potential to support a reliable and secure NEM, as and when they are deployed at scale. When coupled with VRE, batteries allow energy to be stored during times of low demand and dispatched at times of peak demand. They can also respond faster than other energy storage or generation technologies, almost instantaneously, to help maintain grid stability.

Understanding the role that BESS play in providing inertial response and fast frequency response will be vital to promoting better system reliability security. Noting that there has already been significant work undertaken in the frequency control frameworks review and identifying the opportunities for fast frequency response in the NEM, testing the actual physical ability of deployed BESS to provide these services at scale are the likely next steps.

8.2.5 Ensuring the value of behind the meter BESS are realised

For behind the meter BESS, the challenges are different. With significant and ongoing penetration of rooftop solar generation, there is opportunity for the uptake of residential BESS to accelerate over coming years. Better market awareness, improving technology and declining costs are likely to play a major role in driving deployment, as will state government facilitation programs, if and where they are continued. A major issue for policymakers will be to effectively accommodate the expected uptake in residential BESS to optimise its economic value. There are likely to be issues if market arrangements regarding control mechanisms for residential and C&I BESS, which have the potential to deliver major commercial and system benefits), do not keep pace with technologies, or tariff arrangements aggravate electricity cost pressures for households without solar PV and BESS assets.

Batteries can be installed in a range of areas, they do not typically require large site footprints, and can be arrayed in small or large quantities as needed. However, because of these features, batteries can also present considerable problems for the network when they are distributed widely across regions and not controlled in a coordinated manner. Indeed, Australia's electricity network was not originally devised for vast amounts of DER such as rooftop solar PV and BESS. These resources effectively increase the complexity of operating the power network and maintaining security.

Smaller scale BESS installed in high volumes can alter power flows within short time intervals, potentially discharging to the grid simultaneously due to programmed price signal responses or because of coordinated (uncoordinated) action by a third-party aggregator. Importantly, these DER responses can be difficult to predict and plan for. Understanding this generation source and profile will become more crucial in the future as greater numbers of consumers invest in home battery systems.

It is important to note that consumers will invest in batteries behind the meter that provide a direct benefit to them, and as such there will be a component of CR or NCR in any real-world uptake pathway. This means that understanding the difference between these two configurations irrespective of their comparison to grid deployment pathways is crucial to informing the future benefit of behind the meter batteries.

Controlled BESS can provide load shifting, frequency and voltage support services that non-controlled BESS cannot, providing several additional value streams to the network. This translates to a significantly higher return for the controlled deployment pathways examined than for non-controlled BESS.

The analysis highlights some issues for energy market policy. A key implication is that with effective telemetry and communications infrastructure, a mechanism to aggregate resources and supporting standards and regulations, distributed BESS have significant potential to enhance power system security.

Further development of market rules to improve visibility of DER and enable effective orchestration of resources for services like voltage and frequency controls should be a priority [46]. While reforms to allow batteries and demand response aggregators to provide certain system support services have been introduced in recent years, they have some way to go.

There will likely be an important role for the continued demonstration of how distributed BESS could be integrated to deliver better system security, including through the application of new communication controls or aggregation mechanisms, or analytics that automate or enable households to make more informed self-consumption or grid discharge decisions.

There is potential that unclear messaging to consumers may have perverse impacts. Some consumers may not fully understand the difference between different BESS deployments. As a result, consumer investments may not necessarily deliver outcomes which maximise network benefits. For example, consumers' investment into non-controlled BESS may result in them not securing the benefits they intended and cause further issues for the network. These investments may also drive increased uptake of rooftop solar, leading to further dynamic issues and reverse flows. Further, where consumers invest in controlled BESS or a VPP, these investments may stop realising benefits if they leave the program or products are not clear about what benefits can be achieved.

Both AEMO and DNSPs will require visibility of BESS when deployed at scale in order to manage the market and network, respectively. Where it is not possible to ensure that all behind the meter BESS

are controlled, it will be beneficial to determine if non-controlled batteries operate in a predictable fashion at high deployment.

Relevant demonstration projects could further the investigations being completed by the existing ARENA-funded VPPs and extend research into non-aggregated responses which have yet to be tested. This would recognise the clear trend towards a more distributed network and the reality that the system will become increasingly complex to manage unless effective market integration models can be developed.

8.2.6 Aligning tariff reform and social equity

In recent years there have been significant changes to consumer tariffs, both at the NSP level and retail level. The aim of network tariff reforms has been to develop tariff structures that are more reflective of the actual cost drivers for networks and ensure fairness of pricing for consumers.

Currently, consumers that utilise behind the meter BESS to reduce their tariffs will reduce overall revenues for network providers, particularly in the existing regulatory period. It is likely that network providers will have to increase their tariff prices to recover these costs in their next regulatory period. This cost will disproportionately affect consumers without DER. Consumers that can afford to install BESS (as with solar PV) are more likely to have above average incomes and household wealth, further increasing the inequality observed across consumer groups.

Customers are subject to a retail rate which does not always reflect the actual network costs and tariff arbitrage may have perverse outcomes including cross-subsidisation. It will be important to understand if retail offerings encourage BESS behaviour that increases costs for others in the long term.

This issue needs to be managed by government and industry, especially in the context of structural changes in Australia’s energy market and pressures on the rising cost of energy.

Appendix A

Battery cost review

Appendix A Battery cost review

Table 47 HV BESS cost review

Source	Rated output (kW)	Energy capacity (kWh)	Capex ($)	Capex ($/kWh)	Opex ($ p.a.)	Opex ($/kWh p.a.)	Battery component cost ($)	% battery component cost	Project life	Notes
Projects										
ARENA funded battery 1	30,000	8,000	$28,904,446	$3,613	$272,000	$34.00	$24,189,590	83.7%	12	
ARENA funded battery 2	25,000	50,000	$41,190,000	$824	-	-	-	-	-	
ARENA funded battery 3	30,000	30,000	$42,384,529	$1,413	$830,142	$27.67	$23,440,000	55.3%	15	
Selected system size	**25,000**	**37,500**								Used for HV sizing
Studies										
ACIL Allen [47]	-	-	-	-	-	-	-	-	10	
Lazard [12]	100,000	800,000	$575,000,000	$719	-	-	-	-	20	
Lazard [12]	100,000	400,000	$291,000,000	$728	-	-	-	-	-	
EPRI [12]	20,000	80,000	$59,000,000	$738	-	-	-	-	-	
EPRI [12]	40,000	240,000	$173,000,000	$721	-	-	-	-	-	
EPRI [12]	75,000	300,000	$219,000,000	$730	-	-	-	-	-	
ARENA [12]	30,000	30,000	$26,000,000	$867	-	-	-	-	-	
ARENA [12]	28,000	54,000	$42,000,000	$778	-	-	-	-	-	
ARENA [12]	100,000	400,000	$291,000,000	$728	-	-	-	-	-	
Confidential AECOM project	20,000	20,000	$13,710,000	$686	$358,639	$17.93	-	-	15	
Confidential AECOM project	120,000	60,000	$75,000,000	$1,250	$650,000	$10.83	-	-	10	
Confidential AECOM project	50,000	200,000	$79,720,957	$399	$7,703,522	$38.52	-	-	15	Not included in average costs because the project uses a vanadium-redox battery technology
Confidential AECOM project	200,000	200,000	$201,400,000	$1,007	$3,924,208	$19.62	-	-	30	
Confidential AECOM project	25,000	50,000	$355,679,000	$7,114	$1,962,390	$39.25	-	-	25	Not included in average costs due to it being an outlier
Confidential AECOM project	20,000	20,000	$27,000,000	$1,350	$36,000	$1.80	-	-	30	
Average of selected projects and studies				**$1,077**		**$18.64**	**-**	**69.5%**	**17.8**	Used for HV cost estimates

Table 48 MV BESS cost review

Source	Rated output (kW)	Energy capacity (kWh)	Capex ($)	Capex ($/kWh)	Opex ($ p.a.)	Opex ($/kWh p.a.)	Battery-component cost ($)	% battery-component cost	Project life	Notes
Projects										
ARENA funded battery 4	1,000	1,500	$1,800,000	$1,200	$40,000	$26.67	$1,600,000	88.9%	10	
Thomastown	1,000	1,000								Costing data unavailable
Selected system size	**1,000**	**1,000**								Used for MV sizing
Studies										
Lazard [12]	4,000	16,000	$11,900,000	$744						
Lazard [12]	2,000	2,000	$2,000,000							
Lazard [12]	1,000	8,000	$5,700,000	$713						
Lazard [12]	10,000	5,000	$5,700,000	$1,140						
EPRI [12]	15,000	60,000	$44,000,000	$733						
EPRI [12]	3,000	6,000	$4,900,000	$817						
Confidential AECOM project	9,000	4,000	$6,251,902	$1,563	$102,807	$25.70			10	
Confidential AECOM project	10,000	10,000	$13,055,942	$1,306	$80,467	$8.05			10	
Confidential AECOM project	10,000	10,000	$13,510,300	$1,351	$199,049	$19.90			15	
Confidential AECOM project	5,000	10,000	$7,265,000	$727	$25,000	$2.50			25	
ACIL Allen [47]									10	
Average of selected projects and studies				**$1,029**		**$16.56**		**88.9%**	**13.3**	Used for MV cost estimates

Table 49 LV cost review

Source	Rated output (kW)	Energy capacity (kWh)	Capex ($)	Capex ($/kWh)	Opex ($ p.a.)	Opex ($/kWh p.a.)	Battery-component cost ($)	% battery-component cost	Project life	Notes
Studies										
Lazard [12]	500	1,500	$1,200,000	$800.00					20	
ACIL Allen [47]									10	
AECOM estimate				$1,029		$16.56		88.9%	13.3	Estimate provided by engineering team based on similarity to MV
Selected system size	**50**	**125**								Used for LV sizing
Average of selected projects and studies				**$915**		**$16.56**		**88.9%**	**14.4**	Used for LV cost estimates

Table 50 Residential BESS cost review

Source	Rated output (kW)	Energy capacity (kWh)	Capex ($)	Capex ($/kWh)	Opex ($ p.a.)	Opex ($/kWh p.a.)	Battery-component cost ($)	% battery-component cost	Project life	Notes
Projects										
ARENA funded VPP	5	12	$13,000	$1,083			$10,900.00	83.8%		
ARENA funded VPP	5	14	$14,584	$1,080					10	
Confidential AECOM VPP project	20,000	40,000	$33,784,340	$845	$134,591	$3.36			15	Rated output is for entire VPP, which consists of multiple residential systems
Confidential AECOM VPP project	5,000	5,000	$6,156,741	$1,231	$53,615	$10.72			15	Rated output is for entire VPP, which consists of multiple residential systems
Confidential AECOM VPP project	5,000	10,000	$14,888,400	$1,489					10	Rated output is for entire VPP, which consists of multiple residential systems
Selected system size	**5**	**12.5**								Used for P3/P4 sizing
Studies										
Lazard [12]	5	10	$15,000	$1,500						
NREL [48]	3	6	$9,500	$1,583						
NREL [48]	5	20	$21,000	$1,050						
ARENA [12]	5	10	$14,000	$1,429						
ARENA [12]	5	13	$16,000	$1,250						
Average of selected projects and studies				**$1,254**		**$7.04**		**83.8%**	**12.5**	Used for P3/P4 cost estimates

Table 51 Commercial and Industrial BESS cost review

Source	Rated output (kW)	Energy capacity (kWh)	Capex ($)	Capex ($/kWh)	Opex ($ p.a.)	Opex ($/kWh p.a.)	Battery-component cost ($)	% battery-component cost	Project life	Notes
Projects										
Dominos, NSW [49]	50	135	$130,000	$962.96						Sizing not used because premises are smaller than average
ARENA funded VPP	60	72	$430,733	$5,982.40						Sizing not used because premises are smaller than average. Costing not used because capex is an outlier from the studies
Selected system size	**100**	**300**								Sizing provided by client and used for P5/P6 sizing
Studies										
Lazard [12]	500	2,000	$1,600,000	$800						
Lazard [12]	100	200	$205,000	$1,025.00						
ARENA [12]	3,000	2,900	$2,900,000	$1,000.00						
AECOM estimate					$2,641.46	$8.80		83.8%	12.5	Cost estimate provided by engineering team and based on capex equivalent with P3/P4, and opex scaled by 125% of P3/P4
Average of selected projects and studies				**$947**		**$8.80**		**83.8%**	**12.5**	Used for P5/P6 cost estimates

Appendix B

Electricity network characteristics

Appendix B Electricity network characteristics

The current and projected values for a selection of electricity network characteristics to 2038 are summarised in Table 52.

Table 52 Scenario characteristics

Scenarios									
Characteristic		**Low [17]**		**Medium [17]**		**High [17]**		**Rapid trans. [16]**	
Time-period		**2018/19**	**2037/38**	**2018/19**	**2037/38**	**2018/19**	**2037/38**	**2018/19**	**2037/38**
Peak demand (MW)		35,663	32,057	38,050	39,506	38,823	43,463	43,532	48,591
Consumption (GWh)		170,631	124,623	179,809	185,635	183,491	210,832	230,482	288,158
EV penetration (% of operational demand)		0.01%	2.74%	0.02%	6.07%	0.50%	12.68%	0.01%	10.00%
Rooftop PV generation (GWh)		9,475	29,864	9,475	29,864	9,475	29,864	12,281	55,526
Generated energy mix (GWh)	Non-renewable	142,953	60,785	153,280	69,212	157,249	63,081	154,167	67,708
	Renewable	48,292	101,799	48,311	160,855	48,303	195,690	79,167	223,958
Transmission capacity growth (MW)[2]		-	17,945	-	32,885	-	39,485	-	39,362
Interconnector capacity (MW)		2,400	9,200	2,400	9,200	2,400	9,200	2,400	9,200
Generation retirement (MW)	Non-renewable	-	16,680	-	15,220	-	16,640	-	33,814
	Renewable	-	-	-	-	-	-	-	1,749
Installation of BESS storage capacity (37.5MWh units)		5 units per year		8 units per year		10 units per year		10 units per year	
Total installed BESS storage capacity (MWh)		320	4,070	320	6,320	320	7,820	320	7,820

[2] Transmission capacity for 2018-19 is assumed equal for all scenarios and the change in capacity is used in the economic model.

Appendix C

Technical assessment details

Appendix C Technical assessment detail

Table 53 Base generation capex/opex avoidance and deferral – Annual MWh offset of new solar/wind generation (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	336,802	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	420,431	705,198	1,012,515
H	0	471,763	147,584	46,151	0	291,707	0	297,339	849,543	1,064,273	1,193,591	1,391,516	1,673,432	2,190,277	2,563,563	2,791,694	3,861,617	4,437,062	4,180,393	4,212,978	3,821,335
RT	0	488,402	359,245	779,440	1,199,636	1,619,831	2,040,027	2,460,222	2,880,418	3,300,613	3,720,809	4,141,004	4,561,200	4,981,395	5,401,591	5,821,786	6,241,981	6,662,177	7,082,372	7,502,568	9,141,779
MV																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	336,802	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	420,431	705,198	1,012,515
H	0	471,763	147,584	46,151	0	291,707	0	297,339	849,543	1,064,273	1,193,591	1,391,516	1,673,432	2,190,277	2,563,563	2,791,694	3,861,617	4,437,062	4,180,393	4,212,978	3,821,335
RT	0	488,402	359,245	779,440	1,199,636	1,619,831	2,040,027	2,460,222	2,880,418	3,300,613	3,720,809	4,141,004	4,561,200	4,981,395	5,401,591	5,821,786	6,241,981	6,662,177	7,082,372	7,502,568	9,141,779
LV																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	336,802	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	420,431	705,198	1,012,515
H	0	467,168	146,147	45,702	0	288,867	0	294,443	841,270	1,053,909	1,181,967	1,377,965	1,657,136	2,168,947	2,538,597	2,764,507	3,824,011	4,393,851	4,139,683	4,171,950	3,784,121
RT	0	476,317	350,356	760,154	1,169,952	1,579,750	1,989,548	2,399,346	2,809,144	3,218,943	3,628,741	4,038,539	4,448,337	4,858,135	5,267,933	5,677,731	6,087,530	6,497,328	6,907,126	7,316,924	8,915,574
CR																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	336,802	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	420,431	705,198	1,012,515
H	0	467,168	146,147	45,702	0	288,867	0	294,443	841,270	1,053,909	1,181,967	1,377,965	1,657,136	2,168,947	2,538,597	2,764,507	3,824,011	4,393,851	4,139,683	4,171,950	3,784,121
RT	0	476,317	350,356	760,154	1,169,952	1,579,750	1,989,548	2,399,346	2,809,144	3,218,943	3,628,741	4,038,539	4,448,337	4,858,135	5,267,933	5,677,731	6,087,530	6,497,328	6,907,126	7,316,924	8,915,574
CCI																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	336,802	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	420,431	705,198	1,012,515
H	0	421,527	131,869	41,237	0	260,645	0	265,677	759,080	950,944	1,066,492	1,243,341	1,495,238	1,957,047	2,290,583	2,494,421	3,450,414	3,964,583	3,735,246	3,764,361	3,414,422
RT	0	426,106	313,422	680,021	1,046,619	1,413,218	1,779,816	2,146,415	2,513,013	2,879,612	3,246,211	3,612,809	3,979,408	4,346,006	4,712,605	5,079,203	5,445,802	5,812,400	6,178,999	6,545,597	7,975,723

Table 54 Transmission capex/opex avoidance and deferral - Annual $M of deferred transmission upgrades ($M, 2019)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV, MV, LV, CR, CCI																					
L	0	0	5	50	142	525	0	0	0	0	0	0	75	80	1	0	0	0	0	0	0
M	0	0	5	50	142	525	525	0	0	0	0	0	75	80	8	21	0	0	0	0	0
H	0	0	5	50	80	142	525	525	8	0	0	0	75	70	1	11	0	0	0	0	0
RT	0	0	5	50	80	142	525	525	8	0	0	0	75	70	1	11	0	0	0	0	0

Table 55 Distribution capex/opex avoidance and deferral – Annual value of deferred distribution augmentation ($M, 2019)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
MV																					
L	16.267	45.557	3.252	3.252	9.755	39.045	9.755	9.755	6.503	6.503	26.030	13.015	81.358	19.518	84.610	29.282	139.938	169.228	205.021	234.311	0.000
M	29.282	71.595	6.503	9.755	16.267	61.831	16.267	16.267	13.015	9.755	42.305	19.518	130.175	32.542	136.678	45.557	224.548	270.113	331.944	377.509	436.089
H	35.793	91.121	9.755	9.755	19.518	78.098	19.518	19.518	16.267	13.015	52.068	26.030	162.716	42.305	172.479	58.571	283.127	338.456	413.302	471.882	546.737
RT	35.793	91.121	9.755	9.755	19.518	78.098	19.518	19.518	16.267	13.015	52.068	26.030	162.716	42.305	172.479	58.571	283.127	338.456	413.302	471.882	546.737
LV																					
L	45.857	114.965	0.000	0.000	22.929	92.037	22.929	22.929	22.929	0.000	68.786	22.929	230.253	45.857	230.253	68.786	391.398	460.506	575.794	667.831	759.867
M	68.786	207.002	22.929	22.929	45.857	161.145	45.857	45.857	22.929	22.929	114.965	45.857	368.469	92.037	391.398	114.965	621.651	759.867	921.335	1,059.551	1,220.696
H	92.037	253.182	22.929	22.929	45.857	207.002	45.857	45.857	45.857	22.929	137.894	68.786	460.506	114.965	483.435	161.145	783.118	944.263	1,174.516	1,335.984	1,543.308
RT	92.037	253.182	22.929	22.929	45.857	207.002	45.857	45.857	45.857	22.929	137.894	68.786	460.506	114.965	483.435	161.145	783.118	944.263	1,174.516	1,335.984	1,543.308

Table 56 Peaking plant capex/opex avoidance and deferral – Annual MWh offset of new gas peaker generation (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	0	0	0	232,951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H	0	0	130,752	0	217,405	0	0	0	0	0	0	0	0	0	0	0	0	83,558	147,000	0	1,480,830
RT	0	78,428	498,338	113,059	537,678	152,906	138,328	4,469	64,491	77,167	128,769	17,986	0	0	168,342	36,038	0	101,727	163,253	210,295	2,196,105
MV																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	0	0	0	232,951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H	0	0	130,752	0	217,405	0	0	0	0	0	0	0	0	0	0	0	0	83,558	147,000	0	1,480,830
RT	0	78,428	498,338	113,059	537,678	152,906	138,328	4,469	64,491	77,167	128,769	17,986	0	0	168,342	36,038	0	101,727	163,253	210,295	2,196,105
LV																					
L	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	0	0	0	232,951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H	0	0	130,752	0	217,405	0	0	0	0	0	0	0	0	0	0	0	0	83,558	147,000	0	1,480,830
RT	0	78,428	331,136	113,059	537,678	152,906	138,328	4,469	64,491	77,167	128,769	17,986	0	0	168,342	36,038	0	101,727	163,253	210,295	2,196,105

Table 57 Fuel savings for gas peaking plant - Annual MWh offset of gas peaker generation (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV																					
L	165,052	261,763	358,473	455,184	551,894	648,604	745,315	842,025	938,736	1,035,446	1,132,156	1,228,867	1,325,577	1,422,288	1,518,998	1,615,708	1,712,419	1,809,129	1,905,840	2,002,550	2,099,260
M	165,052	319,789	474,526	629,262	783,999	938,736	1,093,472	1,248,209	1,402,946	1,557,682	1,712,419	1,867,155	2,021,892	2,176,629	2,331,365	2,486,102	2,640,839	2,795,575	2,950,312	3,105,049	3,259,785
H	165,052	358,473	551,894	745,315	938,736	1,132,156	1,325,577	1,518,998	1,712,419	1,905,840	2,099,260	2,292,681	2,486,102	2,679,523	2,872,944	3,066,364	3,259,785	3,453,206	3,646,627	3,840,048	4,033,468
RT	165,052	358,473	551,894	745,315	938,736	1,132,156	1,325,577	1,518,998	1,712,419	1,905,840	2,099,260	2,292,681	2,486,102	2,679,523	2,872,944	3,066,364	3,259,785	3,453,206	3,646,627	3,840,048	4,033,468
MV																					
L	247,579	392,644	537,710	682,775	827,841	972,907	1,117,972	1,263,038	1,408,103	1,553,169	1,698,235	1,843,300	1,988,366	2,133,431	2,278,497	2,423,563	2,568,628	2,713,694	2,858,759	3,003,825	3,148,891
M	247,579	479,684	711,789	943,894	1,175,998	1,408,103	1,640,208	1,872,313	2,104,418	2,336,523	2,568,628	2,800,733	3,032,838	3,264,943	3,497,048	3,729,153	3,961,258	4,193,363	4,425,468	4,657,573	4,889,678
H	247,579	537,710	827,841	1,117,972	1,408,103	1,698,235	1,988,366	2,278,497	2,568,628	2,858,759	3,148,891	3,439,022	3,729,153	4,019,284	4,309,415	4,599,547	4,889,678	5,179,809	5,469,940	5,760,071	6,050,203
RT	247,579	537,710	827,841	1,117,972	1,408,103	1,698,235	1,988,366	2,278,497	2,568,628	2,858,759	3,148,891	3,439,022	3,729,153	4,019,284	4,309,415	4,599,547	4,889,678	5,179,809	5,469,940	5,760,071	6,050,203
LV																					
L	99,031	157,058	215,084	273,110	331,136	389,163	447,189	505,215	563,241	621,268	679,294	737,320	795,346	853,373	911,399	969,425	1,027,451	1,085,478	1,143,504	1,201,530	1,259,556
M	99,031	191,873	284,715	377,557	470,399	563,241	656,083	748,925	841,767	934,609	1,027,451	1,120,293	1,213,135	1,305,977	1,398,819	1,491,661	1,584,503	1,677,345	1,770,187	1,863,029	1,955,871
H	99,031	215,084	331,136	447,189	563,241	679,294	795,346	911,399	1,027,451	1,143,504	1,259,556	1,375,609	1,491,661	1,607,714	1,723,766	1,839,819	1,955,871	2,071,924	2,187,976	2,304,029	2,420,081
RT	99,031	215,084	331,136	447,189	563,241	679,294	795,346	911,399	1,027,451	1,143,504	1,259,556	1,375,609	1,491,661	1,607,714	1,723,766	1,839,819	1,955,871	2,071,924	2,187,976	2,304,029	2,420,081

Table 58 Fuel savings for dispatchable diesel generators - Annual MWh offset of dispatchable diesel generation (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
CCI and NCCI																					
L	229	364	498	632	766	901	1,035	1,169	1,304	1,438	1,572	1,706	1,841	1,975	2,109	2,244	2,378	2,512	2,647	2,781	2,915
M	229	444	659	874	1,089	1,304	1,518	1,733	1,948	2,163	2,378	2,593	2,808	3,023	3,237	3,452	3,667	3,882	4,097	4,312	4,527
H	229	498	766	1,035	1,304	1,572	1,841	2,109	2,378	2,647	2,915	3,184	3,452	3,721	3,990	4,258	4,527	4,795	5,064	5,333	5,601
RT	229	498	766	1,035	1,304	1,572	1,841	2,109	2,378	2,647	2,915	3,184	3,452	3,721	3,990	4,258	4,527	4,795	5,064	5,333	5,601

Table 59 Maximising intermittent generator utilisation – Rooftop solar utilisation (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
CR and NCR																					
L	76,173	121,991	169,379	215,433	257,913	316,476	366,780	416,211	466,124	520,823	570,882	623,289	674,266	728,522	782,867	834,650	887,038	941,523	993,178	1,046,514	1,101,024
M	76,173	149,033	224,214	297,822	366,381	458,041	538,114	616,987	696,625	783,505	863,476	947,034	1,028,453	1,114,910	1,201,549	1,284,282	1,367,963	1,454,897	1,537,477	1,622,670	1,709,698
H	76,173	167,061	260,771	352,749	438,693	552,417	652,336	750,837	850,293	958,626	1,058,538	1,162,863	1,264,577	1,372,501	1,480,669	1,584,037	1,688,579	1,797,147	1,900,343	2,006,774	2,115,481
RT	76,173	167,061	260,771	352,749	438,693	552,417	652,336	750,837	850,293	958,626	1,058,538	1,162,863	1,264,577	1,372,501	1,480,669	1,584,037	1,688,579	1,797,147	1,900,343	2,006,774	2,115,481
CCI and NCCI																					
L	63,477	101,659	141,149	179,527	214,928	263,730	305,650	346,843	388,437	434,019	475,735	519,408	561,889	607,102	652,389	695,542	739,199	784,602	827,648	872,095	917,520
M	63,477	124,194	186,845	248,185	305,318	381,700	448,428	514,156	580,521	652,921	719,563	789,195	857,044	929,091	1,001,290	1,070,235	1,139,969	1,212,414	1,281,231	1,352,225	1,424,749
H	63,477	139,218	217,309	293,957	365,578	460,348	543,613	625,698	708,577	798,855	882,115	969,053	1,053,814	1,143,751	1,233,891	1,320,031	1,407,149	1,497,623	1,583,619	1,672,312	1,762,901
RT	63,477	139,218	217,309	293,957	365,578	460,348	543,613	625,698	708,577	798,855	882,115	969,053	1,053,814	1,143,751	1,233,891	1,320,031	1,407,149	1,497,623	1,583,619	1,672,312	1,762,901

Table 60 Maximising intermittent generator utilisation – Increased wind utilisation (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV																					
L	302,303	503,859	552,649	577,498	598,329	605,118	768,146	747,121	766,073	723,598	767,150	805,593	753,937	735,927	775,698	763,519	805,418	840,963	948,279	926,522	981,853
M	302,616	503,793	554,606	593,367	646,208	728,029	776,395	744,649	752,898	739,892	796,274	808,098	774,553	768,570	772,239	837,120	879,038	980,537	1,063,788	1,028,018	1,027,550
H	302,485	589,873	589,690	628,183	674,030	801,393	831,769	800,607	851,895	859,746	945,679	988,728	1,008,051	1,007,804	1,000,234	1,008,825	996,946	1,154,342	1,209,660	1,198,016	1,208,670
RT	415,501	641,873	707,853	808,389	904,428	1,035,208	1,121,274	1,161,394	1,253,031	1,323,143	1,444,760	1,535,982	1,604,016	1,641,279	1,692,028	1,741,112	1,785,557	1,981,911	2,077,246	2,145,160	2,214,985
MV																					
L	302,303	503,859	552,649	577,498	598,329	605,118	768,146	747,121	766,073	723,598	767,150	805,593	753,937	735,927	775,698	763,519	805,418	840,963	948,279	926,522	981,853
M	302,616	503,793	554,606	593,367	646,208	728,029	776,395	744,649	752,898	739,892	796,274	808,098	774,553	768,570	772,239	837,120	879,038	980,537	1,063,788	1,028,018	1,027,550
H	302,485	589,873	589,690	628,183	674,030	801,393	831,769	800,607	851,895	859,746	945,679	988,728	1,008,051	1,007,804	1,000,234	1,008,825	996,946	1,154,342	1,209,660	1,198,016	1,208,670
RT	415,501	641,873	707,853	808,389	904,428	1,035,208	1,121,274	1,161,394	1,253,031	1,323,143	1,444,760	1,535,982	1,604,016	1,641,279	1,692,028	1,741,112	1,785,557	1,981,911	2,077,246	2,145,160	2,214,985
LV																					
L	302,303	503,859	552,649	577,498	598,329	605,118	768,146	747,121	766,073	723,598	767,150	805,593	753,937	735,927	775,698	763,519	805,418	840,963	948,279	926,522	981,853
M	302,616	503,793	554,606	593,367	646,208	728,029	776,395	744,649	752,898	739,892	796,274	808,098	774,553	768,570	772,239	837,120	879,038	980,537	1,063,788	1,028,018	1,027,550
H	302,485	589,873	589,690	628,183	674,030	801,393	831,769	800,607	851,895	859,746	945,679	988,728	1,008,051	1,007,804	1,000,234	1,008,825	996,946	1,154,342	1,209,660	1,198,016	1,208,670
RT	415,501	641,873	707,853	808,389	904,428	1,035,208	1,121,274	1,161,394	1,253,031	1,323,143	1,444,760	1,535,982	1,604,016	1,641,279	1,692,028	1,741,112	1,785,557	1,981,911	2,077,246	2,145,160	2,214,985

Table 61 Maximising intermittent generator utilisation – New utility solar installed (MW)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
L	0	200	0	96	160	584	160	578	737	616	506	277	0	0	0	0	0	1,098	200	0	0
M	0	627	0	47	843	584	1,127	1,288	737	668	792	761	0	311	2,810	0	3,923	4,742	3,816	934	1,614
H	0	845	0	96	1,819	1,127	2,434	2,929	2,177	2,390	1,115	2,256	2,602	2,308	1,362	1,608	3,867	2,265	2,635	0	0
RT	0	902	203	309	2,356	1,527	3,214	3,692	2,899	3,259	1,981	3,033	2,983	2,785	2,546	2,304	5,047	2,946	3,288	1,329	956

Table 62 Reduced T&D losses - Annual MWh offset of T&D power losses (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV-NCCI																					
L	286,016	283,495	281,508	277,127	272,949	271,459	270,212	270,124	268,544	267,758	261,105	254,681	249,886	241,964	232,569	226,540	218,816	214,587	209,824	208,897	206,756
M	286,016	288,990	288,556	287,786	285,298	287,105	285,630	286,870	287,830	288,778	285,086	285,279	283,410	284,886	283,633	283,697	287,875	288,592	292,742	295,283	298,026
H	286,016	290,182	291,505	290,596	289,958	292,796	289,916	292,847	297,795	299,719	300,877	302,651	305,177	309,808	313,153	315,197	324,784	329,940	327,640	327,932	324,423
RT	286,016	290,329	293,550	297,317	301,084	304,851	308,618	312,385	316,152	319,919	323,686	327,453	331,220	334,987	338,754	342,521	346,288	350,055	353,822	357,589	372,284

Table 63 Reduced USE - Annual MWh offset of USE (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
MV																					
L	17	27	38	48	58	68	78	88	99	109	119	129	139	149	160	170	180	190	200	210	220
M	17	34	50	66	82	99	115	131	147	164	180	196	212	229	245	261	277	294	310	326	342
H	17	38	58	78	99	119	139	160	180	200	220	241	261	281	302	322	342	363	383	403	424
RT	17	38	58	78	99	119	139	160	180	200	220	241	261	281	302	322	342	363	383	403	424
LV																					
L	65	104	142	181	219	258	296	335	373	411	450	488	527	565	604	642	680	719	757	796	834
M	66	127	189	250	312	373	434	496	557	619	680	742	803	865	926	988	1,049	1,111	1,172	1,234	1,295
H	66	142	219	296	373	450	527	604	680	757	834	911	988	1,065	1,142	1,218	1,295	1,372	1,449	1,526	1,603
RT	66	142	219	296	373	450	527	604	680	757	834	911	988	1,065	1,142	1,218	1,295	1,372	1,449	1,526	1,603
CR/NCR																					
L	21.61	33.47	45.32	56.43	66.92	77.93	88.41	99.36	110.63	120.66	129.14	137.89	144.90	150.69	156.15	160.67	167.70	175.45	180.86	187.86	194.69
M	21.61	40.89	59.99	78.01	95.07	112.79	129.70	147.28	165.34	181.51	195.33	209.51	221.01	230.61	239.65	247.22	258.63	271.12	279.97	291.29	302.32
H	21.61	45.84	69.77	92.40	113.83	136.03	157.23	179.24	201.81	222.09	239.45	257.25	271.75	283.89	295.32	304.93	319.24	334.89	346.05	360.24	374.08
RT	21.61	45.84	69.77	92.40	113.83	136.03	157.23	179.24	201.81	222.09	239.45	257.25	271.75	283.89	295.32	304.93	319.24	334.89	346.05	360.24	374.08
CCI/NCCI																					
L	7.58	11.88	16.28	20.52	24.62	29.02	33.31	37.89	42.70	47.12	51.04	55.15	58.65	61.73	64.73	67.41	71.20	75.39	78.64	82.67	86.70
M	7.58	14.52	21.55	28.36	34.98	42.00	48.88	56.17	63.81	70.89	77.20	83.80	89.46	94.47	99.35	103.72	109.81	116.49	121.74	128.18	134.63
H	7.58	16.27	25.07	33.59	41.88	50.65	59.25	68.35	77.88	86.74	94.64	102.90	110.00	116.29	122.43	127.93	135.54	143.89	150.47	158.52	166.58
RT	7.58	16.27	25.07	33.59	41.88	50.65	59.25	68.35	77.88	86.74	94.64	102.90	110.00	116.29	122.43	127.93	135.54	143.89	150.47	158.52	166.58

Table 64 FCAS regulation BESS offset (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV																					
L	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
M	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
H	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
RT	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
MV																					
L	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
M	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
H	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
RT	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
LV																					
L	1,927,590	2,306,839	3,003,460	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
M	1,927,590	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
H	1,927,590	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860
RT	1,927,590	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860	3,011,860

Table 65 FCAS contingency BESS offset (MWh)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV																					
L	5,913,872	9,379,032	12,844,192	16,309,351	19,774,511	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
M	5,913,872	11,458,128	17,002,383	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
H	5,913,872	12,844,192	19,774,511	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
RT	5,913,872	12,844,192	19,774,511	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
MV																					
L	8,870,809	14,068,548	19,266,288	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
M	8,870,809	17,187,192	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
H	8,870,809	19,266,288	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
RT	8,870,809	19,266,288	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
LV																					
L	3,548,323	5,627,419	7,706,515	9,785,611	11,864,707	13,943,802	16,022,898	18,101,994	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
M	3,548,323	6,874,877	10,201,430	13,527,983	16,854,536	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
H	3,548,323	7,706,515	11,864,707	16,022,898	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
RT	3,548,323	7,706,515	11,864,707	16,022,898	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
CR																					
L	3,548,323	5,627,419	7,706,515	9,785,611	11,864,707	13,943,802	16,022,898	18,101,994	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
M	3,548,323	6,874,877	10,201,430	13,527,983	16,854,536	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
H	3,548,323	7,706,515	11,864,707	16,022,898	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
RT	3,548,323	7,706,515	11,864,707	16,022,898	20,181,090	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
CCI																					
L	2,956,936	4,689,516	6,422,096	8,154,676	9,887,255	11,619,835	13,352,415	15,084,995	16,817,575	18,550,155	20,282,734	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
M	2,956,936	5,729,064	8,501,192	11,273,319	14,045,447	16,817,575	19,589,702	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
H	2,956,936	6,422,096	9,887,255	13,352,415	16,817,575	20,282,734	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958
RT	2,956,936	6,422,096	9,887,255	13,352,415	16,817,575	20,282,734	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958	20,790,958

Table 66 SRAS providers BESS offset (Number of providers)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39
HV																					
L	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RT	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix D

References

Appendix D References

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