


Storage Requirements for Reliable Electricity in Australia

Report prepared by the
Institute for Sustainable Futures for the
Australian Council of Learned Academies

Institute for Sustainable Futures
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About the authors

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Acknowledgements

This study was funded by the Australian Renewable Energy Agency (ARENA) with additional support from the Australian Council of Learned Societies (ACOLA). The authors are grateful for guidance by Dan Sturrock and Scott Beltman of ARENA and by Professor Quentin Grafton.

Citation

Please cite this report as: Rutovitz, J., James, G., Teske S., Mpofu, S., Usher, J, Morris, T., and Alexander, D. 2017. Storage Requirements for Reliable Electricity in Australia. Report prepared by the Institute for Sustainable Futures for the Australian Council of Learned Academies.

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Executive Summary

Key findings

This study provides reassurance that power system reliability can be maintained in Australia's electricity system at very high penetrations of renewable energy. Reliability has two components, with very distinct requirements, for energy adequacy (is there enough energy at any given hour) and energy security (can the system withstand sudden changes).

This study found only very minor storage requirements for energy adequacy until renewable energy supplies well above 50% of electricity. Estimated requirements for system security, which may be met by storage or other technologies, already occur and will dominate until very high penetrations of renewable energy are reached. The requirements for energy adequacy and security in 2030 are summarised in Figure 1 for three possible scenarios of renewable electricity generation.

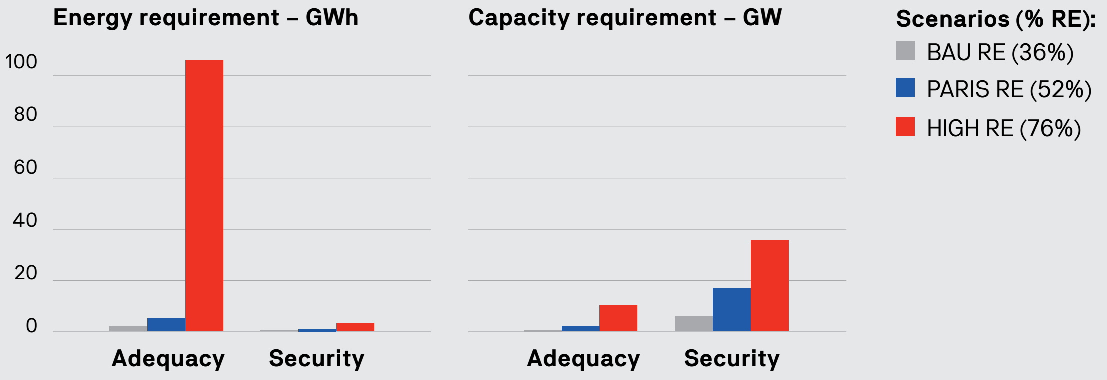
The study provides reassurance that both adequacy and security requirements may be met with readily available technologies, although the policy and regulatory environment may require modification to ensure that we get the most cost effective system outcome. The projected cost for meeting the security requirements at 2030 in the PARIS RE scenario (52% renewable generation) by batteries alone, for example, would be in the order of $11 billion at 2030 prices , and this would also easily meet the adequacy requirements at that time. Of course, requirements for security are likely to be met by a mix of generation and storage technologies, and not by a single solution.

Australia should undertake strategic planning now to meet the requirements for energy adequacy with a zero emission electricity sector in order to get the best outcomes. Firstly, while energy security requirements dominate in the short term, the lowest cost solutions for adequacy may well mitigate security requirements at much lower renewable penetrations. Planning should not be left until high penetrations of renewables are achieved, as some technologies, for example pumped hydro or development of power to gas storage capability, have long lead times. Secondly, there may be strategic advantages attached to storage solutions, such as the potential to become a zero emission energy exporter via one of the hydrogen pathways.

Research is therefore needed on the optimum balance of generation, storage, and interconnection taking into account both cost and the long term strategic opportunities for Australia.

It would be highly advantageous to extend this study to undertake cost optimisation between generation, storage, interconnectors, and demand side measures, factoring in the requirements for both security and energy adequacy. This should include a quantitative market impact analysis, as energy storage may become a price setter rather than a price taker for some energy services. The study would best be undertaken with a stepped approach to reaching a zero emission electricity system, and should include extensive analysis of weather data.

Figure 1: Adequacy and security requirements at 2030, three scenarios



The main requirement for **ADEQUACY** is for energy storage (GWh)

The main requirement for **SECURITY** is for additional capacity (GW)

Penstocks feeding the Tarraleah Power Station, a pumped-storage hydroelectric power station in Tasmania, Australia.

Introduction

The study identifies the energy storage requirement for power system reliability, or “keeping the lights on”. This requirement has two components that in engineering terminology are called adequacy and security. System adequacy is the ability to supply enough energy at the right times to meet customer demand. System security is the ability of the system to withstand sudden changes or contingency events, such as the failure of a large generator, load or transmission line. Providing both adequacy and security is a core function of the Australian Energy Market Operator (AEMO).

Different approaches were used for assessing power system adequacy and security. Understanding adequacy, and the impacts of daily and seasonal variability of demand and variable renewable energy sources, required an hourly model of potential generation and energy demand. This was performed for each state in the National Electricity Market, including the southwest of Western Australia, for an entire year.

The study identified a worst case for energy adequacy, based on low wind output, within the available seven year dataset for wind and solar . It would be prudent to extend this study to allow for further interrogation of wind and solar data, and to calculate storage requirements based on data for multiple years.

Security, on the other hand, is about the ability of the power system to make a rapid transition after contingency events like the loss of a major generator, load or transmission line. An initial assessment of security was based on the potential decrease in system inertia due to the increase in asynchronous supply, such as wind and solar PV generation, in each state. Inertia, typically from turbines in coal, gas or hydro power plants, has been used to keep the grid frequency stable due to the rotating mass of turbines. Wind turbines also have inertia, that is used in some jurisdictions (for example, Hydro Quebec, Brazil, and Ontario) to increase security, given suitable control settings. Other forms of fast frequency response (FFR) may also be required.

The energy scenarios

The energy generation mix is a crucial input to this assessment, and for this study it is bounded by a “business as usual” scenario (BAU RE) that has continued growth of renewable capacity under present conditions and assumes about half of currently proposed projects go ahead, and by a “High Renewables” scenario (HIGH RE) that has aggressive growth to reach 100% renewable electricity by 2035. Between these two is a third scenario (PARIS RE) that has been designed to meet Australia’s emission reduction obligations under the Paris COP21 agreement.

It should be emphasised that the generation mix used in each scenario does not represent either the least cost generation mix, nor the optimum mix of generation and storage. Generation scenarios were used from published sources in order to explore the range of storage which might be required by 2030, and one of the key findings of the work is that an optimisation study of generation, storage and interconnection should be undertaken.

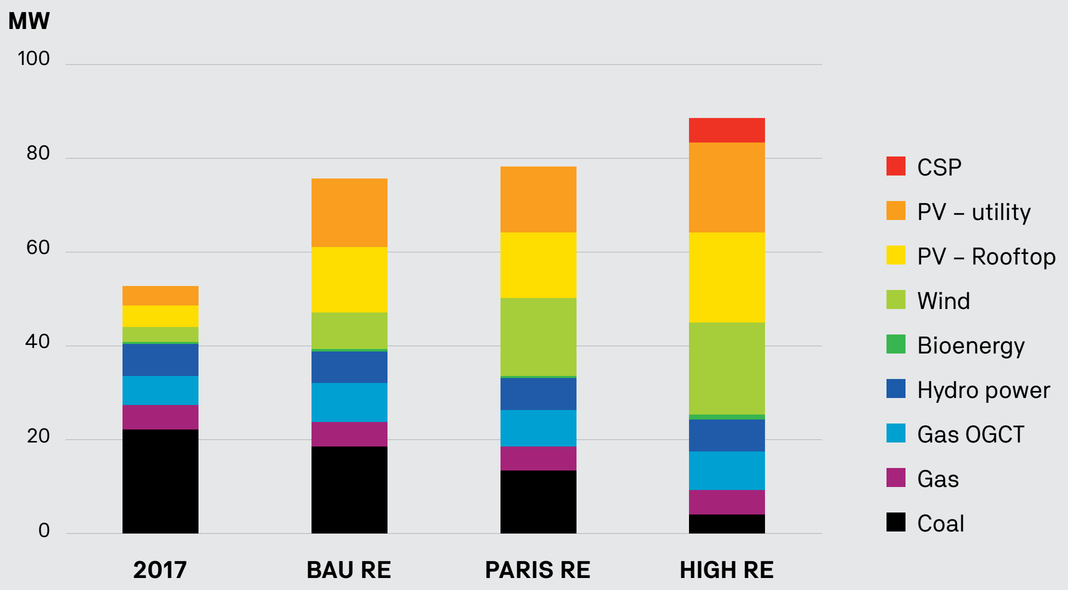
The generation capacities used in each scenario are compared to the current energy mix in Figure 2. Energy generation by type is an output from the model, which depends on both the hourly demand, and the dispatch order. The proportion of renewable generation by scenario was 36% in the BAU RE, 52% in the Paris RE, and 76% in the High RE.

BAU RE
36%
Renewable Generation by 2030

PARIS RE
52%
Renewable Generation by 2030

HIGH RE
76%
Renewable Generation by 2030

Figure 2: Total generation capacity by scenario in 2030



The storage requirement

Table 1 shows the calculated energy storage requirements for Australia's power supply to 2030 according to three possible scenarios. Note that any storage installed for adequacy purposes is likely to contribute to the requirement for security, and vice versa.

The adequacy requirement is primarily for a quantity of energy (GWh). While demand response and demand management could reduce this requirement, it is likely that the majority will need to be provided by stored energy within the given supply mix.

The security requirement is primarily for near-instantaneous delivery of power (GW) as FFR to compensate for sudden shocks to system operation. The figures given in Table 1 are based on the assumption that this FFR is provided entirely by energy storage, although there are many options to provide this service.

The requirements for system security were found to exceed the requirements for adequacy until very high renewable penetrations. In the HIGH RE scenario, the energy storage requirement for adequacy is 105 GWh. However, using energy storage solutions to provide system security capacity would also make a significant contribution to meeting the adequacy requirement. Assuming that the security requirement is met by batteries and that these provide two hours of storage, which is a common configuration in today's battery market, the need for energy storage for adequacy in the HIGH RE scenario is reduced by two thirds at 2030, based on the outcomes shown in Table 1. Pumped hydro storage capable of operating in synchronous condenser mode can also help to meet both security and adequacy requirements, although a pumped hydro facility would not be installed purely to meet a security requirement.

The findings of this study concur with an analysis of Germany's storage requirements by the Fraunhofer Institute (Pape et al. 2014), which similarly concluded that the requirements for FFR dominate the requirement for energy storage until very high penetrations of renewable energy generation, and that the energy adequacy storage requirement is relatively low even at penetrations of 50% renewable energy.

Table 1 Summary of storage requirements: BAU RE, PARIS RE, and HIGH RE (2030)

		2017	BAU RE 2030	PARIS RE 2030	HIGH RE 2030
Renewable % of generation		17%	36%	52%	75%
Storage requirement for energy adequacy	GWh	-	1.5	5	105
	GW	0.2	0.4	1.5	9.7
Storage requirement for system security	GWh	0.1	0.5	1.4	2.9
	GW	**1.3**	**5.8**	**16.8**	**35.2**
Total demand	GWh	216,955	239,134	239,134	239,134
Total capacity	GW	60	79	85	101

The energy storage requirements for reliability are low until very high proportions of renewable energy are reached. Even then, storage solutions used to provide system security can go a long way to also meeting adequacy requirement.

The effect of interconnectors

Interconnectors play an important role in providing system adequacy. The option of doubling the existing interconnector capacities rather than installing storage was tested for the HIGH RE and PARIS RE scenarios by running the energy adequacy model with existing interconnector capacities doubled. The storage requirement went down by 15 GWh (14%) in the HIGH RE scenario, and by 1 GWh (less than 1%) in the PARIS RE scenario. Increasing interconnectors would be a capital intensive undertaking, and this study has not attempted to compare the costs with installing storage. However, it is noted that in the High Renewable scenario curtailment was a significant issue prior to installation of storage. This may be more effectively addressed by bulk storage technologies than interconnectors, as there may be a large overlap in periods of over- and under-production. from renewable energy generators in adjacent states.

Northern Australia

Northern Australia, comprising northern WA, the NT, and northwest Queensland, are not included in this assessment because their electricity generation is dominated by gas and diesel. There will be limited demand for storage to provide system adequacy for the foreseeable future, when supplying local loads, and using batteries to help manage hybrid diesel-renewable or gas-renewable local power stations is already a well-understood proposition. Nevertheless, there is an interesting opportunity to scale up the energy storage industry in Northern Australia in order to facilitate the development of a renewable energy export industry, by one of several proposed pathways.

The PS10 solar power plant near Seville in Spain is the world's first commercial concentrating solar power tower. It stores superheated and pressurised water that is evaporated and used to run a steam turbine to generate electricity.

Cost comparison of storage technologies

The energy storage technologies that should be deployed to meet the requirement are not specified. Rather, cost projections were undertaken to quantify one of the factors that will determine this choice. Other factors include the suitability of each technology for meeting adequacy or security requirements, public response to large-scale infrastructure projects, geographical constraints and planning requirements, uptake of energy storage for purposes other than power system reliability, and the availability of alternative solutions that are not energy storage.

A restricted set of energy storage technologies was considered: pumped hydro storage, compressed air storage (in the form that uses compressed air to increase the efficiency of a turbine fuelled by natural gas), hydrogen produced by hydrolysis, molten salt to store heat for concentrating solar thermal generation, and lithium ion, zinc bromine, and advanced lead acid batteries. This is not a comprehensive set of options; it is intended to represent a range of technologies suitable for deployment at very large scale. The cost projections indicate that molten salt is the cheapest storage option overall, although it is only suitable to store electricity from the associated CSP generator. The most cost-effective bulk energy storage suitable to store electricity from diverse generation sources was projected to be compressed air, then pumped hydro storage, followed by zinc bromine or lithium ion batteries (projected 2030 prices). However, cost comparisons between storage types are fraught with difficulty as the costs are highly dependent on the use case.

Presently, pumped hydro is the cheapest form of storage to meet an adequacy requirement, although project development times are significant, which increases the risk profile of these investments. Batteries are already cost-effective for FFR if installed with a high power-to-energy ratio and appropriately configured inverters, and systems specifically designed for FFR are already available. Installing GW capacity for the purpose of FFR creates the opportunity to expand their GWh capacity at a lower marginal cost than would be the case without the FFR purpose. Although compressed air storage is potentially cost effective there are limited locations where it would be possible to build at large-scale in Australia, as suitable stable rock formations are restricted. There are also only two existing plants worldwide, which makes reliable cost data problematic. Molten salt storage is the cheapest form of storage, and is likely to be incorporated into every concentrating solar thermal generator as the additional cost is very low compared to the added value derived from dispatchable power.

Policy considerations

Given the internal and external environmental factors involved, it will be important for energy storage policy to promote market growth (on strength and opportunity) while also managing risk (mitigating against weakness and threat). Table 2 gives some guidance on the key elements that government should consider, divided into those policies relating to reducing risk, and those aimed at promoting opportunities. Policy considerations based on SWOT analysis include:

Policy for growth

- **Promote an energy storage mix** that meets Australia's near-term and long-term system needs, and supports our climate targets
- **Pursue timely energy market reform** to create a competitive marketplace for new technologies, services and business models
- **Foster Australian expertise** in storage to build a comparative advantage in both research and deployment
- **Explore the potential for hydrogen** to provide Australia with the capability to export renewable energy to the Asia-Pacific region

Policy for risk

- **Consider intervening** when the market is not promoting investment in potentially lower-cost technologies with longer lead times
- **Respond to changes in renewable energy policy** to ensure that the expansion in variable generation does not adversely impact electricity reliability
- **Monitor the resource availability** for the proposed energy storage mix and consider options for alleviating this risk e.g. lithium recycling
- **Promote knowledge sharing** in the industry with regards to deployment i.e. lessons learned to reduce costs
- **Monitor any flow-on impacts** of energy storage uptake to other technologies in the energy mix, particularly gas generation, and ensure this does not adversely impact system reliability.

In South Australia the 100 MW/129 MWh Tesla Powerpack energy storage system (due for completion in December 2017) will charge using renewable energy from the nearby Hornsdale Wind Farm to deliver electricity to the grid during peak hours.

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Abbreviations

ACOLA	Australian Council of Learned Academies
ACT	Australian Capital Territory
AECOM	Architecture, Engineering, Construction, Operations, and Management
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESDB	Australian Energy Storage Database
AREMI	Australian Renewable Energy Mapping Infrastructure
ARENA	Australian Renewable Energy Agency
AS/NZS	Australian/New Zealand standards
ATSE	Australian Academy of Technology and Engineering
AUD	Australian Dollar
BAU RE	Business as Usual Renewable Energy (one of the generation mix scenarios in this study)
BEV	Battery electric vehicle
BOS	Balance of System
CAES	Compressed Air Energy Storage
CAPEX	Capital expenditure
CCA	Climate Change Authority
CCGT	Combined-Cycle Gas Turbine
CEC	Clean Energy Council
CEFC	Clean Energy Finance Corporation
CO2	Carbon dioxide
COAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrating Solar Power
CST	Concentrated Solar Thermal
CTO	Chief Technology Officer

DEG	Average Rated Capacity
DER	Distributed Energy Resources (local generation, demand management, and energy storage)
DNSP	Distribution Network Service Provider
DOD	Depth of Discharge
EIA	Energy Information Administration
EMTP	ElectroMagnetic Transients Program
EOI	Expression of interest
EPRI	Electric Power Research Institute
ESCRI-SA	Energy Storage for Commercial Renewable Integration – South Australia
EU	European Union
EUR	Euro
EV	Electric vehicle
EWG	Expert Working Group
FCAS	Frequency Control Ancillary Service
FFR	Fast Frequency Response
GHG	Greenhouse gas
GTM Research	Greentech Media Research
GW	Gigawatt = 1000 Megawatts
GWh	Gigawatt hour = 1000 Megawatt hours
HIGH RE	High Renewable Energy (one of the generation mix scenarios in this study)
HVDC	High Voltage Direct Current (electricity transmission technology)
ICT	Information and Communications Technology
IoT	Internet of Things
IRENA	International Renewable Energy Agency
Kt	Kilotonnes
kW	Kilowatt = 1000 Watts (a unit of power)
kWh	Kilowatt hour = 1000 Watt hours (a unit of electrical energy)
LCA	Life-Cycle Analysis

LCE	Lithium Carbonate Equivalent
LCOE	Levelised Cost of Energy
LCOS	Levelised Cost of Storage
$LiCoO_2$	Lithium Cobalt Oxide
$LiFePO_4$	Lithium Iron Phosphate
Li-ion	Lithium ion
LMO	Lithium Manganese Oxide
LMP	Lithium Metal Polymer
LNG	Liquified natural gas
LT	Lithium Titanate
MW	Megawatt = 1000 kilowatts
MWh	Megawatt hour = 1000 kilowatt hours
NCA	Lithium Nickel Cobalt Aluminium Oxide
NEFR	National Electricity Forecasting Report published by AEMO
NEM	National Electricity Market
NMC	Lithium Nickel Manganese Cobalt
NPV	Net Present Value
NaS	Sodium-Sulphur
NiCd	Nickel Cadmium
NiMh	Nickel Metal hydride
NiZn	Nickel Zinc
NSW	New South Wales
NT	Northern Territory
OCS	Office of the Chief Scientist
O&M	Operation and Maintenance
OPEX	Operational expenditure
PARIS RE	Renewable Energy consistent with Australia's GHG emission reduction commitment at COP21 in Paris (one of the generation mix scenarios in this study)
PASA	Project Assessment of System Adequacy
PHES	Pumped Hydro Energy Storage

PHEV	Plug-in Hybrid Electric Vehicle
PV	Photovoltaic
QLD	Queensland
R&D	Research and development
RE	Renewable energy
RET	Renewable Energy Target
RoCoF	Rate of change of frequency
SA	South Australia
SWIS	Southwest Interconnected System (in southern WA)
SWOT	Strengths-Weaknesses-Opportunities-Threats
TAS	Tasmania
T&D	Transmission and distribution
TRL	Technology readiness level (a scale from 1-9 indicating the stages of development from theoretical research to full commercialisation)
TW	Terrawatts = 1000 Gigawatts
TWh	Terrawatt hours = 1000 gigawatt hours
US	United States
USD	United States Dollars
UTS	University of Technology, Sydney
V2G	Vehicle-to-grid
VIC	Victoria
VPP	Virtual Power Plant
VRB	Vanadium Redox Battery
WA	Western Australia
ZnBr	Zinc Bromine

Glossary

Ancillary services	Those services which are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. Ancillary services include frequency control, load following , voltage support and black start services.
Arbitrage	The purchase and sale of an asset in order to profit from a difference in the price. It is a trade that profits by exploiting price differences of identical or similar financial instruments, on different markets or in different forms.
Behind the meter energy storage	Behind the meter refers to storage systems that are located on the end-user's property and connected to their localised energy system, as opposed to the electricity grid.
Black start	The process of restoring an electric power station or a part of an electric grid to operation without relying on the external transmission network.
Capacity (of energy storage)	Either the maximum sustained power output (or input) of a generator or energy storage device (measured in kW, MW, GW) or the amount of energy that may be stored (measured in kWh, MWh, GWh)
Capacity firming	Provides energy to fill-in when variable generation output is below the generator's rated power output; done to provide constant power
Capital intensity	The amount of fixed or real capital present in relation to other factors of production, especially labour.
Charging	The process of injecting energy to be stored into an electricity storage system.
Contingency event	An event affecting the power system, such as the failure or unplanned removal from operational service of a generating unit or transmission network element.
COP21 Paris Agreement	A multinational agreement reached at a conference in 2015, which aimed to achieve a legally binding, universal agreement on climate, with the aim of keeping global warming below 2°C.
Customer energy management	Customers operating storage, and other forms of control, to manage their site loads or generation, to avoid peak demand or capacity charges.
Demand charge	A tariff structure in which the amount that a consumer is charged is based on the maximum power demand (i.e. the highest capacity that is required during the billing period).
Demand side management	The modification of consumer demand for energy through various methods such as financial incentives and behavioural change through education.
Discharging	The process of retrieving energy that has been stored in an electricity storage system.
Distributed energy resources (DER)	Smaller power sources and controllable demand that help to manage supply and demand on local networks, and that can be aggregated to provide services to the wider interconnected electricity grid. As the electricity grid continues to modernise, DER such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid.

Fringe of grid	The parts of an interconnected electricity grid that are furthest from centralised energy sources. Energy storage and other DER can have high value in fringe-of-grid applications, helping to maintain high quality and reliable electricity supply to the regions of the network that are more difficult and costly to supply.
Gas peaking plants	Power plants that generally run only when there is a high demand, known as peak demand, for electricity.
General Exemption Order	An Order in Council made under section 17 of the Electricity Industry Act 2000 and published on 1 May 2002.
Grid connect accreditation	Accreditation to work on grid-connected photovoltaic power systems or energy storage systems
Hydrogen fuel-cell vehicle	A vehicle that uses hydrogen as its on-board fuel for motive power.
Variable generation	A description of a generating unit whose output is non-dispatachable due to its fluctuating nature, including, for example, solar generators, wave turbine generators, wind turbine generators and hydro generators without any material storage capability.
Levelised cost of energy	A summary measure of the overall competitiveness of different generating technologies. It represents the per kilowatt-hour cost (in present dollars) of building and operating a generating plant over an assumed project life and duty cycle.
Levelised cost of storage	A summary measure of the overall competitiveness of different storage technologies. It represents the per kilowatt-hour cost **post storage** (in present dollars) of building and operating a storage facility over an assumed project life, duty cycle, with assumed input costs for the stored electricity.
Load following	Adjusting a power plant's power output as demand for electricity fluctuates throughout the day.
Load shedding	When there is not enough electricity available to meet demand, it could be necessary to interrupt supply to certain areas. This is generally done to prevent the failure of the entire system when unexpectedly high demand or contingency events strain the capacity of the system.
Micro-grid	A localised collection of interconnected electricity loads and sources that can connect to the wider electricity grid and also disconnect from the grid and function autonomously. Also known as a mini-grid.
MESAP/PlaNet	Modular Energy System Analysis and Planning Environment (MESAP) is a software toolbox for energy system analysis, and Planning Network (PlaNet) is a linear network module for MESAP.
NEM	National Electricity Market. The Australian wholesale electricity market that covers the electrically connected states and territories of eastern and southern Australia, and the associated synchronous electricity transmission grid.
Network management	The operation, administration, maintenance, and provisioning of networked systems. Network management is essential to command and control practices and is generally done from a network operations centre.
Network service provider	A party that owns, leases, or operates an electricity network and is registered.

Off grid	Systems which do not use or depend on public utilities and network infrastructure for the supply of electricity.
Peak time	Times when demand for electricity is highest. Typically on-peak times occur during weekdays during the hottest summer months, when normal demand is high and when air conditioners are operating.
Peaking power generation	Quick response power generating plants that provide power at times of peak demand. This often happens when there is a surge in demand associated with a particular event.
Renewable energy integration	Incorporating renewable energy, distributed generation, energy storage, thermally activated technologies, and demand response into the electric distribution and transmission system.
Pumped-hydro energy storage	A type of hydroelectric energy storage used by electric power systems for load balancing. The method stores energy in the form of gravitational potential energy of water, pumped from a lower reservoir to a higher one.
Ring-fencing	The separation within a network service provider of regulated services from contestable business activities or non-regulated services. Regulated services are separated from those services that are delivered by the competitive market, like energy retailing.
Smart meter	An electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing. Smart meters enable two-way communication between the meter and the central system.
Smart network	An advanced electricity network featuring ICT-enabled control systems and distributed energy generation and storage resources
Solar self-consumption	The strategy by which an energy consumer with solar PV generation (sometimes referred to as a prosumer) shifts their power demand to equal or exceed the output of the generator at all times, minimising retail purchase of electricity, and preventing net export of solar energy at a low feed-in tariff. Energy storage can help to achieve this.
Spinning reserve	The extra generating capacity that is available by increasing the power output of generators that are already connected to the power system. For most generators, this increase in power output is achieved by increasing the torque applied to the turbine's rotor.
Standalone energy systems	Off-the-grid electricity systems for locations that are not fitted with an electricity distribution system. Typical systems include one or more methods of electricity generation, energy storage, and regulation.
Standalone power systems accreditation	Accreditation to work on standalone (SPS) photovoltaic power systems (not connected to the grid).
Synchronous generation	Synchronous generation refers to generation whose operation is tightly synchronised to the operating frequency of the power system. The rotating parts of synchronous generating units connected to the power system will be spinning at a rate that divides exactly into the system frequency (in Australia) of 50 Hz or 3,000 revolutions per minute.

Vehicle-to-grid system	A system in which plug-in electric vehicles communicate with the power grid to sell demand response services by either returning electricity to the grid or by throttling their charging rate.
Virtual net metering	A metering arrangement, which refers to when an electricity customer with on-site generation is allowed to assign their exported electricity generation to other site(s).
Voltage support	The ability to produce or absorb reactive power and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the resource's stated reactive capability.

Background

Australia's Chief Scientist, Dr Alan Finkel, has asked the Australian Council of Learned Academies (ACOLA) to develop and deliver a report on the opportunities from, and challenges to, the rapid uptake and widespread use of energy storage in Australia's energy supply and use systems. The project is delivered as a partnership between the Office of the Chief Scientist (OCS) and ACOLA.

The project considers the transformative role that energy storage may play in Australia's energy systems, identifies future economic opportunities and challenges, and describes the current state of and future trends in energy storage technologies. It examines the scientific, technological, economic and social aspects of the role that energy storage can play in Australia's transition to a low-carbon economy over the coming decade and beyond. While acknowledging the diverse applications and services that energy storage technologies can provide, this project focuses on storing significant volumes of low-carbon energy for electricity supply and transport in Australia, as well as research and export opportunities.

The project comprises two parts: **Phase I**, a report outlining current energy storage, and **Phase II**, a collection of discrete work packages that investigate key aspects of the market identified in **Phase I**. More specifically, **Phase I** contains an overview of a broad range of available and emerging energy storage technologies and the diverse applications and services they can provide. It contains:

- a review of existing and emerging energy storage technologies
- an overview of the diverse applications of energy storage technologies in the electricity and transport sectors
- a discussion of the Australian context for energy storage, including an overview of relevant policy and regulatory developments.

Phase II of the project investigates different uptake scenarios for energy storage technologies that can store significant volumes of low-carbon energy for electricity supply and transport in Australia. It identifies Australia's research and industry strengths and weaknesses, assesses opportunities for Australia to participate in the energy storage supply chain, and analyses the economic, social and environmental challenges of significant energy storage uptake in Australia. The project further discusses policy and regulatory implications.

- Work package 1: analyses the storage requirement for reliable electricity in Australia;
- Work package 2: identifies the opportunities for Australian research and industry in the global and local energy storage supply chains, including domestic and export opportunities in manufacturing, software, instruments, knowledge, services and resources;
- Work package 3: identifies the cradle-to-grave environmental and safety benefits and risks presented by uptake of energy storage; and
- Work package 4: examines the social drivers and barriers of energy storage uptake, and the potential benefits or detriments to the public in achieving energy storage uptake targets.

All four work packages discuss how policy and regulatory settings can help to realise the opportunities and benefits of energy storage uptake, and overcome the challenges and potential negative impacts identified over the course of the project.

This report presents the findings of Work Package 1.

1 INTRODUCTION

1.1 Adequacy and Security

Energy storage and the reliability of Australia's electricity system are both very much in the public eye. This study investigates the relationship between the two. It asks: what is the role of energy storage technologies in assuring reliable electricity supply from now until 2030?

At present, the electricity system is experiencing a transition towards renewable energy supplies, as they become cost competitive and their potential to reduce greenhouse gas emissions is appreciated. The implications for reliability are not fully understood, even while they are being extensively debated. Energy storage has the potential to contribute to the two aspects of reliable supply:

- system adequacy – the ability to meet electricity demand at all times of the day, and year, and in future years
- system security – the ability to withstand sudden changes in electricity generation, transmission, or demand.

While there are many other uses for energy storage, and these uses are driving an active market, particularly in residential battery storage, this study has a firm focus on the contribution of energy storage to reliability. The rapidly maturing supply chain, and the improving business case for energy storage of several kinds, are having an important impact on reliability applications and are helping to make them cost-effective.

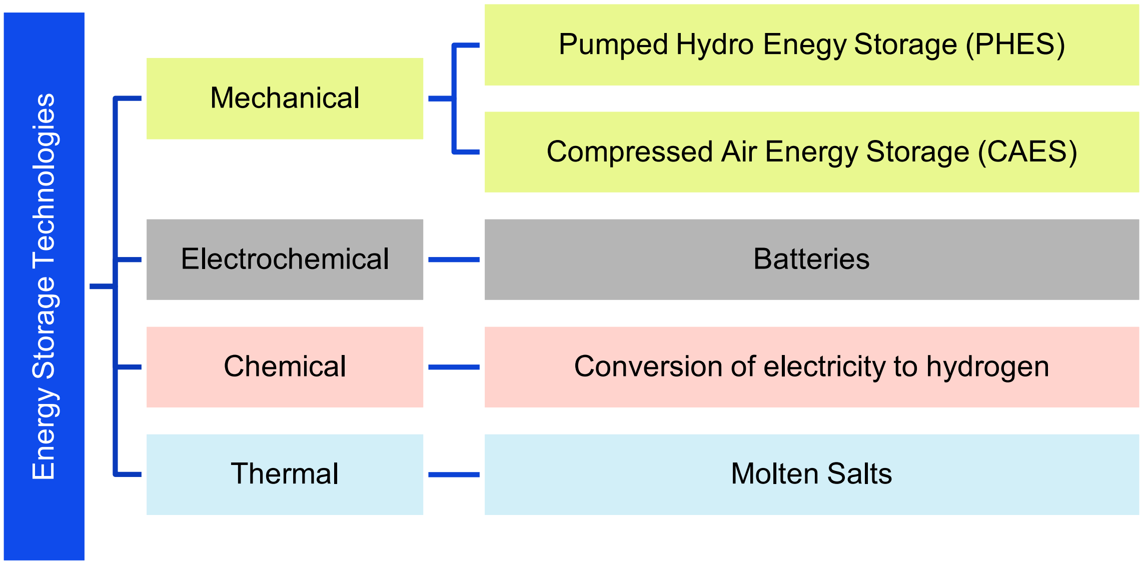
1.2 Technologies included

The characteristics, and consequently the applications of energy storage technologies, vary considerably. A brief overview of the energy storage technologies considered in this report is given Appendix 1, and categorised in

Figure 3. This selection is based on the assumption that only very large amounts of energy storage will be useful for power system reliability, and so it is intended to include those technologies with the best prospects of being used for large-scale energy storage in Australia by 2030.

The selected technologies include pumped hydro, which is widely used at present; compressed air, which has two international examples and projects low costs going forward; and the use of electricity to produce hydrogen for storage, which is still under development but particularly well suited for large-scale energy storage application. Molten salt thermal storage associated with concentrating solar thermal is included because it allows CST to be a dispatchable technology, and battery energy storage is an obvious inclusion, given the present buoyant market conditions.

Figure 3 Classification of key energy storage technologies



From Banfield & Rayner (2016)

1.3 Modelling approach

This report aims at the minimum credible analysis to estimate an energy storage requirement for reliability. It should account for:

- the characteristics of the technologies discussed above
- the existing energy mix in Australia and its potential changes until 2030
- major interconnectors between states (which are separate market regions).

Distinctly different approaches are needed for assessing the two dimensions of reliability, namely power system adequacy and security.

Understanding adequacy, the ability to meet demand, requires a time-series model of available energy sources and energy demand. The variability of demand, and of some renewable energy sources, are the main determinants of adequacy, because fossil-fuel plants have intrinsic energy storage through their fuel supplies, and the fuel supply chain is outside the scope of this study. Security, on the other hand, is about the ability of the power system to transition from one supply–demand balance to another in a short space of time.

Therefore, separate analyses are needed to gauge the adequacy and security requirements for energy storage.

1.3.1 Modelling system adequacy

A model with minimum complexity to study power system adequacy is based on an hourly analysis of supply and demand in each state. The key sources of variability are wind generation, solar generation, and demand; controllable generation sources, along with energy storage, are dispatched to meet any demand that is not supplied by wind and solar generation. Hourly resolution is sufficient to resolve mismatches in supply and demand that would influence energy adequacy, and, if sustained, would make it difficult to meet demand.

For time intervals of less than an hour, the main problem for power systems is not how to provide enough energy to meet demand, but how to respond quickly enough to changing circumstances. Within an hour, the main problem for power systems is how to manage rates of change rather than how to provide enough energy to meet demand. Indeed, many steam turbine generators require several hours to make large changes in their output, and they can take up to a day to reach their full output from a cold start. Energy-based studies of power systems generally use the hour as their unit of time, and hourly historical data are usually available. For studies of power system dynamics, on the other hand, more complex models of generators, and sub-second time resolutions, are required.

Section 4.4 describes the hourly supply and demand model developed for this study. The time series data were obtained from multiple sources. Because system adequacy is limited by unusual circumstances of supply constraint, the analysis of storage requirements depends on statistical extremes and is sensitive to the selection of input data, in particular the choice of year for wind and solar data. Section 5.4.2 describes how a particular year was chosen to demonstrate a challenging period for system adequacy. However, a complete data set for solar and wind was only available for seven years (2003-2010), so results can only be indicative – a full analysis of system adequacy would consider weather data over a longer time period. Unfortunately the project scope did not allow for an extended analysis of weather variation.

1.3.2 Modelling system security

Power systems rely on the inertia of large spinning masses in steam and hydro turbines to maintain a steady frequency. This helps to ensure there is time to respond to sudden changes in electricity generation, transmission or demand.

As renewable energy sources are introduced, the amount of inertia tends to decrease: of the major sources, solar PV generation lacks inertia entirely, while wind generation has inertia that can only be used through explicit control. Considering the changing energy mix from now until 2030, this report estimates the requirement for “fast frequency response” to keep frequency stable as system inertia declines.

This requirement will not necessarily be met by energy storage, but the availability of cost-effective battery energy storage is widely considered to provide a new means for stabilising the grid. The technical capability of battery energy storage to provide this service is assessed in this study.

1.3.3 Implications for energy storage

The energy generation mix is a crucial input to both the adequacy and the security of a power system and is of course unknown for 2030. The approach of this study is to bound the likely generation mix between a “no change” energy scenario which involves continued growth of renewable energy under present conditions, and a “high renewables” scenario that has aggressive growth towards 100% renewable energy by around the middle of the century. Between these two is a third scenario that meets Australia’s greenhouse gas (GHG) emission reduction obligations following the Paris COP21 meeting. By means of these scenarios the range of storage requirements is estimated.

The specific energy storage technology that will be deployed to meet the requirement is not determined. Rather, a thorough analysis of cost projections was undertaken, since cost is one of the main factors which needs to be considered when choosing technologies. Other factors include the suitability of each technology for meeting adequacy or security requirements, public response to large-scale infrastructure projects, geographical constraints and planning requirements, uptake of energy storage for purposes other than power system reliability, and the availability of alternative solutions that do not involve energy storage. This study therefore quantifies the requirement for energy storage and some of the factors that will govern the solution, and highlights key sensitivities.

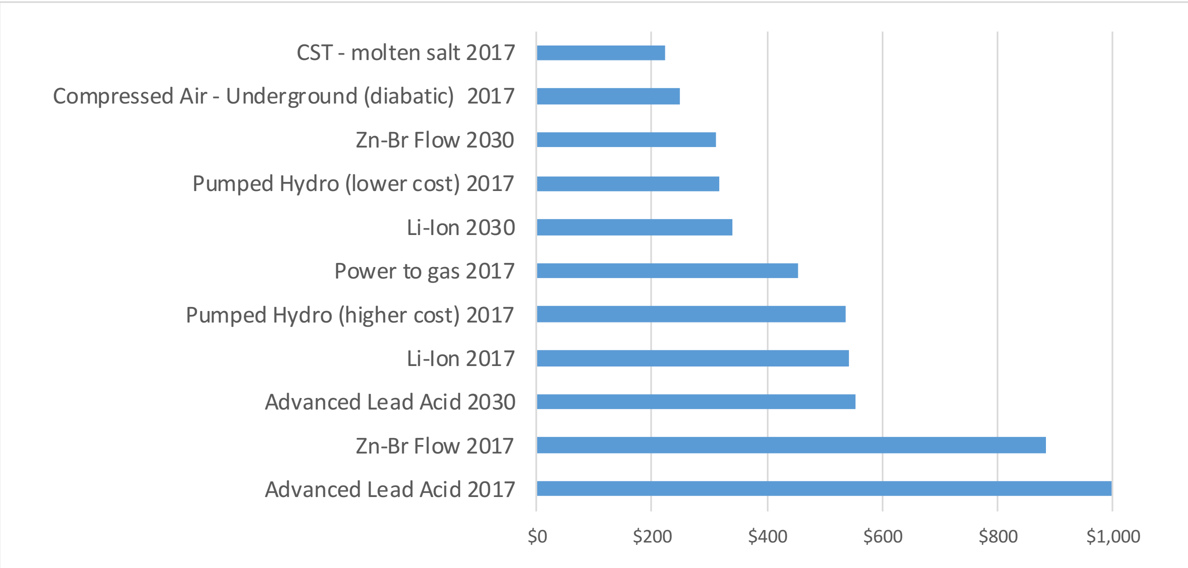
2 STORAGE COST PROJECTIONS

2.1 Key findings

Seven different storage technologies were analysed. These included three types of batteries (advanced lead acid, lithium-ion (Li-Ion) and zinc bromine (Zn-Br)), diabatic compressed air energy storage (CAES), pumped hydro energy storage (PHES), CSP molten salt storage, and power-to-gas conversion.

The Levelised Cost of Storage (LCOS) was used to compare different energy storage technologies, with particular emphasis on the applicability of each technology to supplying energy adequacy in the Australian market. Estimated LCOS values for energy storage applied to power system reliability are shown in Figure 4. There is a high degree of uncertainty in this data, as many assumptions are required to undertake the calculations, and cost is intricately bound up with the use application. For example, the number of cycles per year for the storage and the input electricity price have a high impact on the LCOS, and may vary significantly according to market dynamics, the purpose of the storage, and the location within the network. There is also significant uncertainty about future costs for technologies currently at early development stages, such as next generation CAES and Zn-Br.

Figure 4 Indicative LCOS for bulk storage by technology [$/MWh]



For a full list of input assumptions, see Appendix 7

Different technologies also have highly different characteristics, and finding a suitable technology for a particular purpose may be much more important than the cost. Some technologies are suitable for storing electricity from any generation source, while others, such as molten salt, are paired to a particular generator.

The cost of molten salt storage associated with CST is very low compared to other technologies. Compressed air also appears very cheap, but the cost is highly dependent on the interaction of the gas and electricity price – expensive gas and cheap electricity will result in a higher relative cost for CAES than shown, and vice versa.

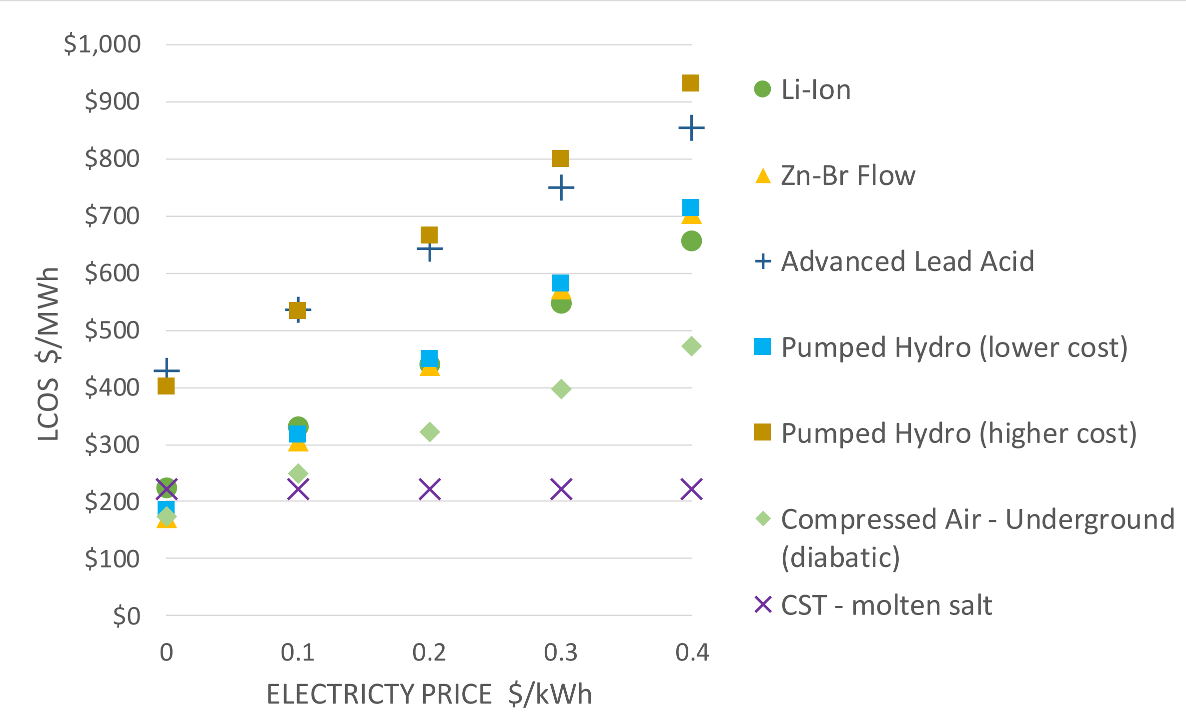
The cost of power-to-gas[3] is high in this assessment, primarily because the round trip efficiency of conversion to electricity is only 40%. However, power-to-gas may be used for other purposes, such as conversion to renewable fuels for export, including ammonia, LNG, or liquid hydrogen. An example of this, power-to-ammonia, is currently under investigation in WA (Want and Cooper 2014), and may be of considerable long-term interest with regard to creating a sustainable long-term export energy industry.

Deployment potential is also varied. Pumped hydro and CAES are dependent on suitable sites, and have long lead times, while batteries may be deployed virtually anywhere in a short period of time.

[3] Electricity used to produce hydrogen for injection into the gas pipeline, followed by use in a gas turbine

The LCOS is directly proportional to the price of electricity for all energy storage technologies except for CAES and molten salt. The LCOS for CAES does not show as strong a correlation to electricity tariff increases as battery storage or pumped hydro, primarily because CAES has a round trip efficiency for electricity of 134%[4] because of the gas input to the system. Thus high electricity prices and low gas prices give CAES a relative advantage compared to other technologies, while high gas prices and low electricity prices relatively disadvantage CAES. The cost of gas is significant for the LCOS of CAES.

Figure 5 Changes in LCOS plotted against changes in electricity price



2.2 Methodology

The biggest challenge associated with performing cost comparisons of energy storage technologies is formulating a metric that can standardise the cost comparison while taking into account the different imperatives of storage that each technology is designed to meet. This is particularly difficult for utility-scale storage solutions such as PHES and CAES, whose costs cannot be generalised as they are site-specific (IRENA 2012; Luo et al. 2014).

Energy storage scholars have approached costing in two ways: by performing profitability analyses of the technologies (Locatelli, Palerma, & Mancini 2015; Parra et al. 2016) or by calculating a discounted cost per unit of discharged electricity (denominated in $/kWh or $/MWh) known as the levelised cost of storage (LCOS) (Julch, 2016), which is effectively the levelised cost of energy discharged from storage.

Profitability analyses investigate how select energy storage technologies can be profitable under different conditions. Locatelli et al. (2015) investigate the profitability of PHES and CAES for the UK market without subsidy, while Parra et al. (2016) explore community energy storage in the UK for the year 2020.

LCOS, the other methodology of energy storage cost analysis, is used in this study. LCOS is defined as the total lifetime cost of an investment divided by the cumulative energy generated out of the storage medium by this investment (Pawel 2014). LCOS has been used extensively in recent literature for energy storage cost analysis (Julch 2016; Pawel 2014; Zakeri and Syri 2015), but a study targeted towards Australia has never been attempted. Industry research, such as that by Lazard (2016), provides a rigorous analysis of the LCOS and its applicability in different use scenarios.

The Lazard formula for LCOS is:

[4] This is the comparison between electricity in and electricity out; the energy round trip efficiency is 47%.

$$\text{LCOS} = \frac{CAPEX}{\#_{cycles} * DoD * C_{rated} * \sum_{n=1}^{N} \frac{(1-DEG*n)}{(1+r)^n}} + \frac{OPEX * \sum_{n=1}^{N} \frac{1}{(1+r)^n}}{\#\ of\ cycles * DoD * C_{rated} * \sum_{n=1}^{N} \frac{(1-DEG*n)}{(1+r)^n}}$$

$$- \frac{\frac{V_{residual}}{(1+r)^{N+1}}}{\mu\left(DO\#\ of\ cycles * DoD * C_{rated} * \sum_{n=1}^{N} \frac{(1-DEG*n)}{(1+r)^n} D\right)} + \frac{P_{electricity}}{\mu(DOD)}$$

where $\#_{cycles}$ is the number of charging/discharging cycles in a year, DOD is the depth of discharge, C_{rated} is the rated capacity, DEG is the annual degradation rate of capacity, N is the project lifetime in years, r is the discount rate, O&M is the Operating and Maintenance cost, $V_{residual}$ is the residual value of the storage system at the end of its lifetime, $P_{electricity}$ is the charging electricity tariff and $\mu(DOD)$ is the round-trip efficiency.

It should be noted that the inputs to the LCOS calculation depend crucially on the use case of the storage, and Lazard (2016) defined ten use cases, five behind the meter and five at utility scale[5]. The likely costs, and more importantly, the operational inputs, will vary according to the use case. The different use cases at utility scale depend on where in the network the storage is located, while the different use cases behind the meter depend more on scale and the degree of isolation of the system.[6]

Lazard (2016) also notes that there are additional value propositions, which are effectively in addition to the energy value, resulting from the provision of grid services. In considering the energy adequacy requirement, the LCOS is an appropriate metric, as it literally assigns a cost based on energy cycling through the storage medium. However, a different calculation may be required to assess and compare the costs of storage for the provision of grid services such as frequency regulation. The LCOS does not therefore measure the value of energy storage to any given stakeholder group, but provides a method for comparing the costs associated with alternative energy storage technologies for a particular storage application. It should be further noted that LCOS is not useful for comparing storage options to generation options without more in-depth analysis, as the input cost for the electricity is a crucial element in the calculation.

The key inputs to the LCOS calculation are the capital cost of the equipment, costs associated with operations and maintenance (O&M), the cost of the electricity to be stored, and the technical parameters associated with the technology, such as round trip efficiency. Many of these parameters vary according to the use case, and in particular, whether the storage is behind or in front of the meter.

The comparisons in this paper are based on the LCOS formula provided above, assuming the storage is in front of the meter, and are not further differentiated by use case.

In order to simplify the calculations, the residual value of all the storage technologies was set at zero. The impact of this simplification was tested empirically and found to be insignificant relative to the uncertainty in the estimates. Further, the cost of the gas tariff was factored into the equation, as this is a major cost influence for CAES. The resulting equation is:

$$\text{LCOS} = \frac{CAPEX}{\#_{cycles} * DoD * C_{rated} * \sum_{n=1}^{N} \frac{(1-DEG*n)}{(1+r)^n}} + \frac{Average\ OPEX * \sum_{n=1}^{N} \frac{1}{(1+r)^n}}{\#\ of\ cycles * DoD * C_{rated} * \sum_{n=1}^{N} \frac{(1-DEG*n)}{(1+r)^n}}$$

$$+ \frac{P_{electricity}}{\mu(DOD)} + (P_{gas} * Gas_{in})$$

where $\#_{cycles}$ is the number of charging/discharging cycles in a year, DOD is the depth of discharge, C_{rated} is the rated capacity, DEG is the annual degradation in rated capacity, r is the discount rate, $P_{electricity}$ is the charging electricity tariff, P_{gas} is the gas tariff, Gas_{in} is the gas required per kWh of electricity and $\mu(DOD)$ is the round-trip efficiency.

[5] The five cases defined are transmission system, peaker replacement, frequency regulation, distribution substation, and distribution feeder.
[6] The five cases defined are microgrid, island, commercial and industrial, commercial appliance, and residential.

Table 3 Data sources for technology costs

	Description	Batteries	PHES	CAES	Power-to-gas	Molten Salt
CSIRO report on energy storage (Brinsmead et al, 2016)	Review of 4 storage technologies that are most relevant to NEM with cost forecasting for 2035	✓				
Renewable and Sustainable Energy Reviews (Journal article) (Zakeri and Syri 2015)	Analysis of storage costs based on a review of 27 papers from 2008-2013	✓		✓	✓	
Applied Energy (Journal article) (Julch 2016)	LCOS analysis for four storage technologies.			✓	✓	
ROAM report to AEMO on pumped hydro (Winch et al. 2012)	NEM-wide assessment of PH potential (sites suitable for 500 MW+) for AEMO 100% modelling		✓			
ASI report on the potential for CST in Australia (Lovegrove et al. 2012)	Examination of the potential of CST in Australia using primary data and 17 secondary sources					✓
Primary research (technology providers)	Survey of 30 residential battery retailers.	✓				

Data for capital costs were collected via a literature review, and primary research into costs was undertaken where possible. Technical data, such as depth of discharge or round-trip efficiency, was obtained from literature, except for Li-ion batteries.

The main sources for cost data, and the technologies they are relevant to, are shown in Table 3. A number of other references were consulted, but were not used other than for gemneral comparison, because they only used secondary source material which was already covered in the references below, because the information they contained has been superseded, or because the information was insufficiently detailed to be used in the comparison (AECOM 2015; Deloitte 2015; IRENA 2015).

2.3 Cost data

2.3.1 Cost data – batteries for energy storage

Three types of battery storage were investigated: advanced lead acid, lithium ion (Li-Ion) and zinc bromine (Zn-Br).

Of the three battery technologies, Li-Ion batteries are the most technically diverse in terms of commercially available options for different cell chemistries. No two manufacturers make Li-Ion cells with precisely the same mix of nickel, cobalt, manganese, iron, aluminium or titanate. These different materials, primarily at the anode, are often used in an effort to reduce cost while simultaneously increasing specific and volumetric energy and power densities. However, as the costs of the various Li-Ion chemistries are comparable, and projected to change at similar rates across all technologies, they are treated as one family in this study. Furthermore, the field of research in Li-Ion batteries is vast and it is widely expected that the dominant chemistries in a decade from now will be different to those dominant today.

Where possible, data was sought from battery vendors, but where that information was unavailable, as was the case with advanced lead acid batteries, prices were obtained from the literature alone. Raw data obtained on 28 unique batteries is shown in Appendix 6. This primary data was sourced from supplier websites between December 2016 and January 2017. In all cases the data sourced from these websites was the direct retail price in foreign currencies. They were later converted to Australian dollars as at 1

January 2017. In addition to price information, the primary research also encompassed technical discovery, which is addressed later in this report.

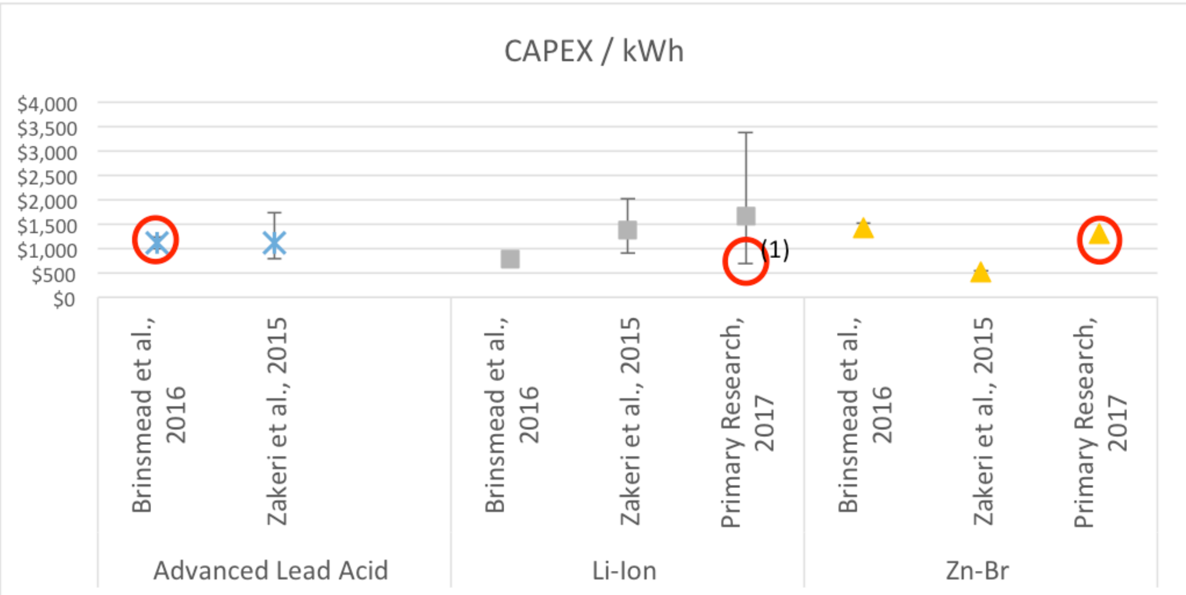
Comparing battery costs is complex, as capital costs may be given with and without inverters, and with or without installation. In order to standardise the comparison, the capital cost for all data sources that excluded the inverter and installation costs was adjusted by adding these costs from the CSIRO storage report (Brinsmead et al. 2016).

Primary data for cost is compared with data from the two key literature sources in Figure 6. The red circles indicate the base prices used prior to projection to 2030. As can be seen, the average prices for advanced lead acid were identical in the two studies. Unfortunately, no primary cost data for advanced lead acid batteries is currently available, as there do not appear to be commercially available options. The current minimum price for Li-Ion batteries is used, as it corresponds to the Tesla batteries, which account for approximately 20% of the world market at present (Tesla Motors 2017; Mancheva 2017). While the Tesla batteries are cheaper than their competitors, the quality, warranty, and reputation are equivalent or better, making it unlikely that end users would choose other providers until such a time as other providers release other price competitive products. This effectively makes the Tesla Powerwall 2 the current benchmark.

At the time of writing a highly public offer from Tesla to provide utility-scale Powerpack batteries to support system security in SA is being widely discussed (Parkinson 2017b). This has encouraged parallel offers from other vendors and illustrates the rate of change in the present battery market. In general terms, the offer anticipates the 2030 costs modelled in this study, which have been used for system cost estimates.

One additional point to note with regards to Zn-Br batteries is that the Zakeri and Syri (2015) research was clearly based on projections that the Zn-Br battery would come down in price, but this has not eventuated, as evidenced by the close agreement between the CSIRO estimate and the actual price obtained from the Zn-Br supplier at current publicly listed prices.

Figure 6 Current capital costs for batteries, including inverter and installation



Note 1: the minimum value from the primary research corresponds to the Tesla Powerwall 2.0

The current cost as indicated is used to project the cost to 2030, using the annual percentage cost reductions by technology projected in the CSIRO report (Brinsmead et al. 2016).[7] Learning rates were applied to the capital cost of the battery only, with an annual reduction of 0.05% per year applied to the installation and inverter costs, as suggested in the same report.

To portray the costs associated with each of the battery technologies as accurately as possible, the CAPEX was adjusted to factor in the average effective capacity over the lifetime of the product. This was done by dividing the CAPEX by the depth of discharge for each of the storage technologies. Li-ion and Zn-Br have a 100% depth of discharge, so only the CAPEX for advanced lead acid changes.

[7] Base case cumulative learning rates from 2017–2030 were 53% for advanced lead acid, 52% for Li-ion, and 79% for Zn-Br.

Table 4 Cost data for LCOS calculation for batteries

	Advanced Lead Acid	Li-Ion	Zn-Br Flow
CAPEX (2017) $/kWh rated, including installation and inverter [(1)]	680	699	1300
CAPEX (2017) $/kWh average effective capacity [(2)]	1511	699	1300
CAPEX (2030) $/kWh rated, including installation and inverter	320	333	272
CAPEX (2030) $/kWh average effective capacity [(2)]	711	333	272
Fixed O&M $/kW/ yr [(3)]	4.8	9.8	6.1
Variable O& M $/kWh throughput [(3)]	0.0048	0.0030	0.0009

Notes

1) CAPEX: Advanced lead acid data from (Cavanagh et al. 2015), Li-Ion data from Tesla Motors, 2017 and Zn-Br Flow data from Redflow, 2017

2) The cost per effective capacity of advanced lead acid increases as a result of the 45% depth of discharge. This is suggested as a maximum from (Cavanagh et al. 2015).

3) O&M: (Zakeri and Syri 2015)

2.3.2 Cost data – Compressed air energy storage

The optimal economic considerations for the construction of CAES plants have been the subject of various studies (Drury et al. 2011; Lund et al. 2009). The studies show that intended capacity and discharge time for CAES dictate whether the compressed air should be stored underground or above ground. Underground salt caverns, natural aquifers, and depleted natural gas reservoirs have been identified as the most cost-efficient options for capacities up to several hundreds of megawatts (discharge time of 8–26 h) (Julch 2016). For lower capacities (within the range of 3–15MW and with a discharge time of 2–4h), above-ground CAES is often the most economic compressed air storage option (Julch 2016).

As previously discussed, costs associated with CAES are site-specific. Since there are only two operational CAES plants, both of which were built more than 20 years ago, most of the cost modelling for CAES plants is speculative, resulting in a large variability in both the CAPEX and OPEX provided in literature. For this study, the cost data used was the average of two sources, Julch et al. (2016) and Zakeri and Syri (2015). The first cost data point was from the results obtained from Julch et al. (2016), who used average costs provided by 14 different European CAES component vendors. The second data point was from Zakeri and Syri (2015) and was the average of papers analysed that included CAES. Zakeri and Syri (2015) analysed 19 different sources of CAES data.

2.3.3 Cost data – Molten salt

It is complex to compare the cost of molten salt storage to other storage technologies, as a fair comparison requires the decoupling of the costs of molten salt storage from the cost of the CSP plant. Unlike other energy storage technologies where the cost of storage can be analysed separately from cost of electricity generation, the cost of molten salts storage is intricately tied to the cost of the plant. Cost breakdown for CSP plants provided by Lovegrove et al. 2012 ranks the solar field as the most important cost element , and molten salts storage as the second. When added to a CSP plant, thermal storage can account for up to one-sixth of the total cost, depending on the specific CSP technology used (IEA-ETSAP and IRENA 2013).

The approach taken here is to consider the incremental cost of storage per kWh electric, including the incremental cost of the associated increase in field size. While the actual configuration of field size to storage to power block is complex, it is generally agreed that the solar multiple will increase proportionately to the amount of storage (Jorgenson et al. 2013). This has the effect of increasing the capacity factor of the plant, so including the incremental costs, in effect, is paying for the additional electrical output. This approach means that the cost of storage includes the cost of electricity, which otherwise would be extremely difficult to assess.

The incremental cost is taken from the average of the 2-hour and the 5-hour incremental costs (normalised) from Lovegrove et al. (2012) in Table 6. This results in a capital cost of AU$490 per kWh_e. This is a conservative approach for two reasons: firstly, CST costs have come down in the five years since 2012, and secondly, the cost given was for a trough plant, and storage costs are lower for the tower systems which are now commonly installed. An O&M cost of 0.015/kWh has been included in the calculation (Lovegrove, Jordan and Wyder 2015).

2.3.4 Cost data – power-to-gas (hydrogen)

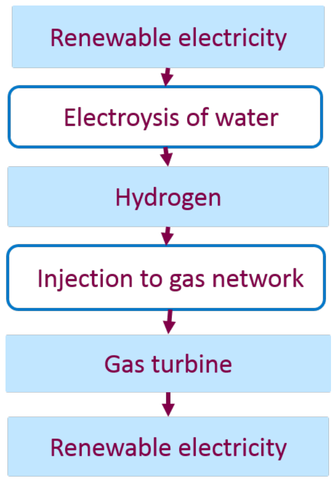
There are many hydrogen pathways from renewable energy, as discussed in Appendix 1. As this study is focussed on 2030, the most practical pathway for hydrogen to electricity is likely to be via storage in the gas network, followed by use in an existing gas turbine, which is shown schematically in Figure 7.

Most power-to-gas systems are compatible with existing infrastructure for natural gas storage, conversion and transmission (Cavanagh et al., 2015). As such, the presence of available natural gas infrastructure needs to be considered when analysing costs associated with power-to-gas. Further, as is the case with CAES, power-to-gas energy systems are site-specific – with CAPEX varying by as much as 90% depending on whether the power-to-gas system employs natural porous rock formations from depleted gas or oil sites, or rock caverns from excavation of impervious rock formations (Zakeri and Syri, 2015).

The major cost components of a power-to-gas system can be broken down into the costs of: the electrolyser, intermediate hydrogen storage tank, CO_2 purification plant, methanation unit for converting the hydrogen to CH_4, gas feed-in system, and the CCGT for reconversion to electricity (Julch 2016). As this technology is still in demonstration and no actual plants are operational yet, the cost of the system is calculated as the sum of the different parts that make up the system.

For this study, the capital cost data used was obtained from Zakeri and Syri (2015), whose survey of 25 papers included nine different sources for hydrogen cost data. Fixed and variable O&M costs were taken from (Julch 2016). The data was in EUR, and converted to AUD for comparison using the currency conversion rate listed in Table 9.

Figure 7 The hydrogen pathway explored for system adequacy: power-to-gas



2.3.5 Cost data – pumped hydro energy storage (PHES)

ROAM consulting undertook a study of pumped hydro potential in the NEM to feed into the AEMO 100% renewables study (Winch et al. 2012), which included a detailed data set for the sites identified (ROAM Consulting 2012). Sites per state which come in under $0.5m and $1m per MWh storage CAPEX are shown in Table 5, giving total potential of approximately 128 GWh. The study did not include the SWIS. ROAM only identified sites where a minimum of 500 MW could be reasonably installed. As can be seen, approximately three-quarters of the storage is at the lower cost ($408,000 per MWh), compared to the higher cost sites which average $980,000/ MWh.

Table 5 Australian pumped hydro potential and costs according to ROAM

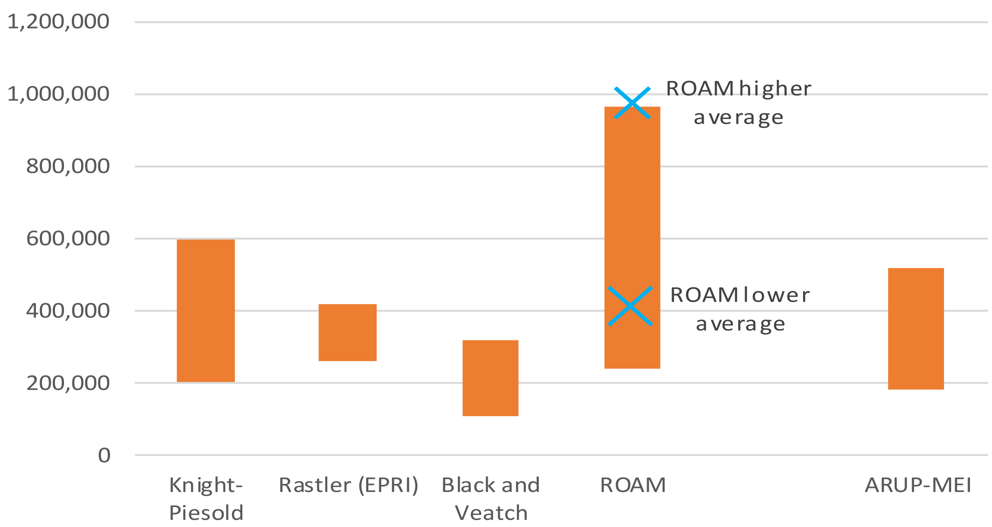
	Storage (MWh) [1]			Average capital cost per MWH storage		
	< $500,000	< $1,000,000	All	< $500,000	< $1,000,000	ALL
NSW	45,308	3,441	48,749	$452,871	$777,443	$475,782
QLD	13,078	2,193	15,271	$509,992	$952,359	$573,518
SA	-	2,071	2,071	$0	$1,027,964	$1,027,964
TAS	39,956	19,990	59,946	$324,827	$1,011,074	$553,670
VIC	-	2,009	2,009	$0	$990,550	$990,550
Total	98,342	29,705	128,047	$408,443	$979,463	$540,910

All data derived from ROAM Consulting 2012. Note 1) ROAM storage potentials have been de-rated by 20%, assuming a maximum 80% discharge.

Figure 8 shows the costs from three studies listed in another recent Australian review (Hearps et al. 2014), as well as the costs from the seven case studies in that review, and the averaged costs from the 48 sites in the ROAM study. The ROAM costs are somewhat higher than those listed in other studies, but the lower-cost sites are well within the range from other reviews.

At the time of writing a present study is mapping the potential for off-river pumped hydro storage to manage the variability of wind and solar generation (ARENA 2017a; Blakers, Stocks, and Lu 2017) towards a 100% renewable energy generation mix (Parkinson 2017a). This work with further elaborate PHES costs and available sites, and is anticipated to see a cost reduction.

Figure 8 Comparative CAPEX for pumped hydro (AU$/ MWh)



Data from Hearps et al. 2014; Knight Piésold 2010; Rastler 2012; ROAM Consulting 2012

2.3.6 Cost summary – PHES, CAES, Molten Salt, Power-to-gas

Table 6 Financial input data for LCOS calculation

	PHES		CAES	Power-to-gas	Molten Salt
	Lower Cost	Higher Cost			
CAPEX (2017) $/kWh average effective capacity (1)	408	979	162	372	490
Fixed O&M $/kW – yr (2)	6.5	6.5	5.5	36.4	n/a
Variable O& M $/kWh throughput (2)	0.0003	0.0003	0.0044	0.0043	0.015

Notes

1) *CAPEX: PHES from Winch et al. 2012; CAES and Power-to-Gas from Zakeri and Syri 2015; molten salt from Lovegrove et al. 2012*

2) *O&M: Zakeri and Syri 2015 except for power-to-gas (derived from Julch 2016) and molten salt (Lovegrove et al. 2015). It should be noted that the capital cost for molten salt includes the cost of the additional field size associated with the storage, so the comparison with capital costs of other storage types is not straightforward.*

2.4 Technical specifications

2.4.1 Batteries

The technical specifications for advanced lead acid batteries were obtained from (Cavanagh et al. 2015). As with cost, the Tesla Powerwall 2 was used as a benchmark for technical specifications, as it has become the leading standard for all Li-Ion batteries, and to some extent, for all large-scale battery storage systems. An alternative would have been to use an average of all existing Li-Ion technologies, but that would be a less accurate depiction of the Li-Ion battery market, as it is expected that competitor batteries will match or improve on both performance and price, as discussed in Section 2.3.1. Red-flow's Zn-Br is the only Zn-Br flow battery that is currently on the market and hence the technical specifications for Redflow were used for the analysis. See Table 8 for a summary of technical specifications used in the LCOS calculations.

2.4.2 CAES

Only two plants, at Hutorf in Germany and McIntosh in the USA, are in operation, with a third plant (ADELE) still undergoing research and development. Average values from these two plants, as provided by the Energy Storage Association, are used in this study. The information about the two operational plants, and the projected data for the adiabatic plant are summarised below in

Table 7. To produce 1kWh of energy, the Huntorf plant requires 0.8kWh of electricity and 1.6kWh of gas, whereas the Alabama plant requires 0.69kWh of electricity and 1.17kWh of gas. These figures were combined to produce an overall estimate of the round trip electrical efficiency of 134%, with the input of gas enabling a greater than unity energy output. As with the other bulk storage technologies, 100% depth of discharge is assumed for CAES.

Table 7 Existing CAES systems

	Diabatic		Adiabatic (in development)
	Huntorf, Germany	McIntosh, Alabama USA	ADELE, Germany
Power Generation (kW)	290,000	110,000	200,000
Cavern Dimensions	2 caverns – 310,000m^3, depth 600m	1 cavern –540,000m^3, depth 450m	No caverns (400m high pressurised container)
Pressure Tolerance	50-70 bar	45-76 bar	100 bar
Production Time	2hrs	26hrs	5hrs
Energy needed to produce 1kWh of energy	0.8kWh of electricity + 1.6kWh of gas	0.69kWh of electricity + 1.17kWh of gas	No electricity needed
Round Trip Efficiency (%)	42%	54%	70%
Storage Capacity (kWh)	640,000	286,0000	1,000,000
Maturity	Commercial	Commercial	R&D

Source: Cavanagh et al., 2015

2.4.3 PHES

The depth of discharge for PHES was taken to be 100% (note that the storage capacity had already been downgraded to an effective capacity of 80%, assuming that 20% would be retained in the reservoir). In theory, water pumped up into a reservoir is available for use to power the generator, but this does not allow for leakage or evaporation. To calculate the total round-trip system efficiency, the efficiency of the pump (88%) was multiplied by the efficiency of the turbine (86%) (Zakeri and Syri 2015), giving an overall efficiency of 76%. This number can be compared against the Hearps et al. (2014) figure of 75% round-trip efficiency.

2.4.4 Molten Salt

The depth of discharge for molten salts was taken to be 100% based on the full amount of molten salts being available for thermal storage. The underlying assumption is that there would be no leaks within the pipes that transfer the molten salts. The overall system efficiency is greater than 95% for indirect systems using oil as the heat transfer fluid and 99% when the molten salt is used as the direct heat transfer fluid, which is the assumed configuration of choice. The molten salt itself is typically a mixture of potassium nitrate, sodium nitrate and sodium nitrite with a temperature range of 149^{0}C to 538^{0}C (Yang and Garimella 2013).

2.4.5 Power-to-gas

The depth of discharge for power-to-gas systems was assumed to be 100% based on the assumption that all the hydrogen being generated will be available for use to convert back to electricity. This assumes that no significant amount of hydrogen leaks in the process. The overall efficiency of the power-to-gas system is a product of the efficiency of the electrolyser (70%), the hydrogen storage system (98%) and the CCGT (58%) (Julch 2016). While Julch (2016) is the only source which has collated efficiency figures for each part of the process, the electrolyser number agrees with the 70% efficiency assessment by Eichman, Townsend, and Melaine (2016). This leads to an overall efficiency of only 40%. However, it should be stressed that this is the result of multiple conversions, from electricity to gas and then back to electricity. For another application, such as conversion to gas for thermal use, or conversion to LNG for export, the round-trip efficiency would be much higher.

2.4.6 Technical summary

Table 8 and Table 9 summarise the technical and financial inputs for the LCOS calculation; the full list of inputs is contained in Appendix 7.

Table 8 Technical input data for the LCOS calculations (all technologies)

	Advanced Lead Acid	Li-Ion	Zn-Br Flow	CAES	PHES	Molten Salts	Power-to-gas
Depth of Discharge (%)	45	100	100	100	100	100	100
Round-trip Efficiency (%)	94	93	75	134	76	100	32
Average effective capacity (%)	90	90	90	100	100	100	100
Project Lifetime (yrs)	15	15	15	40	40	25	20
Sources	1	2	3	4	5	6	7

Notes:

1) *Cavanagh et al. 2015*
2) *Tesla Motors 2016*
3) *Zn-Br Flow data from Redflow 2017*
4) *Julch 2016; Zakeri & Syri 2015*
5) *Winch et al. 2012*
6) *Lovegrove et al. 2012*
7) *Julch 2016; Zakeri & Syri 2015*

Table 9 Financial input to LCOS calculations

Discount rate	8%	
Average electricity price	0.1	$/kWh
Average gas cost	0.060	$/kWh
1 EUR	$1.42	AUD
1 USD	$1.32	AUD

All values are 2017 dollars.

The following assumptions were used:

- The number of cycles per year was set at 220 for all the storage technologies. This assumption was made based on the number of cycles calculated for a pumped hydro scheme operating with a 20% capacity factor. Some studies used an average of 365 cycles a year (1 cycle a day) (Julch 2016; Lazard 2016; Zakeri and Syri 2015) for ease of calculation.
- The total lifetime of each of the technologies was set at 15 years for batteries, 20 years for power-to-gas, 30 years for molten salts, and 40 years for CAES and PHES. These figures lie within the ranges given in literature (Cavanagh et al. 2015; Julch 2016; Zakeri and Syri 2015) as well as those found from primary sources.

2.5 Batteries for security: capital cost

Fast frequency response for security may be achieved by a number of technologies, and this section does not seek to compare costs with other technologies, but rather to estimate the capital cost of batteries to meet this requirement.

Of the three battery technologies, Li-Ion is the most popular choice for low-energy, high-power applications such as those required to support security requirements. Of the 11 utility-scale deployments of energy storage in Australia analysed by CSIRO, only two use advanced lead acid, with only one operational (Cavanagh et al. 2015). Zn-Br's applicability to large-scale applications is limited by the relatively high cost of electrolytes per kilowatt (Lotspeich and Van Holde 2008), so this cost data is based on Li-Ion technology.

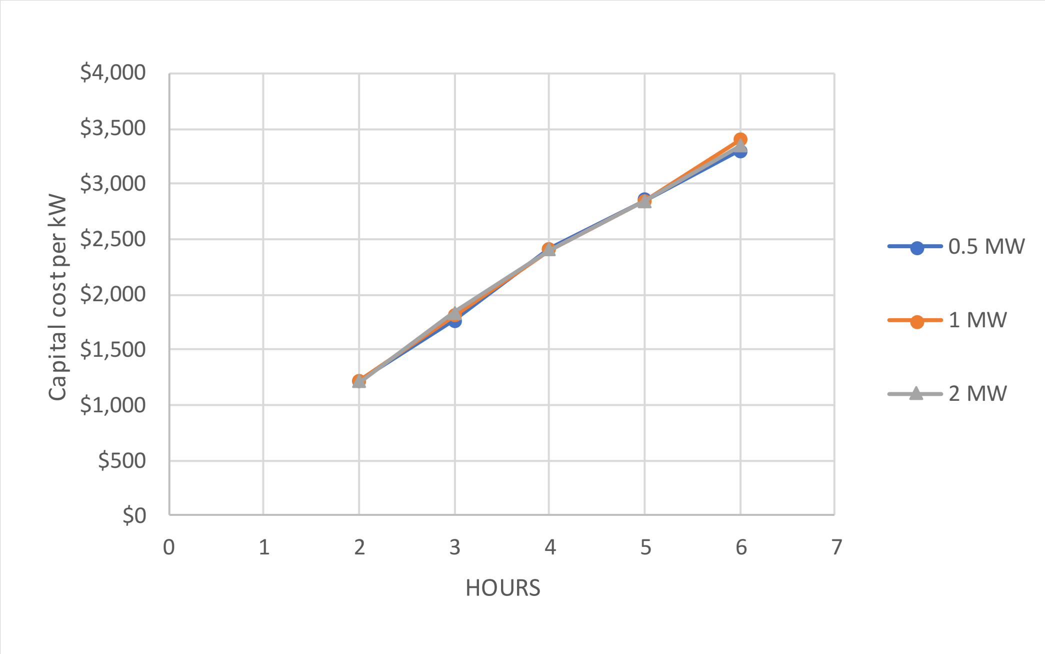
As with residential batteries, the current price is taken from Tesla, whose offering for commercial and utility scale, the Powerpack 2.0, is currently being sold well ahead of Li-ion expert price projections (RMI: Tesla's batteries 7 years ahead of our price predictions, 2017). Cost information for the Powerpack 2.0 is readily available on the Tesla website, some of which is shown in

Figure 9. The costs include the units themselves, inverters, controllers and cabling and site support hardware.

In order to meet security requirements, a half-hour of storage would be adequate. Unfortunately, Tesla does not currently provide half hour batteries, so the cost used in this section are based on a two hour configuration, the lowest which they offer. The costs for 0.5 MW, 1 MW, and 2 MW batteries are shown against the number of hours in

Figure 9. The hours determine the energy density of the battery, as a 1 MW battery with 1 hour of storage will store 1 MWh, with 2 hours will store 2 MWh, and so on.

Figure 9 Utility batteries - cost for different energy configurations (kW versus hours)



Source data: Tesla Powerpack 2, https://www.tesla.com/en_AU/powerpack/design#/

Table 10 Cost data for Tesla batteries, 500 – 6000 kWh

Power (kW)	Energy (KWh)	Cost ($/kW)	Cost ($/kWh)
500	1000	$611,360	$1,223
500	2000	$1,206,120	$2,412
500	3000	$1,647,780	$3,296
1000	2000	$1,218,230	$1,218
1000	4000	$2,407,740	$2,408
1000	6000	$3,401,470	$3,401
2000	4000	$2,431,960	$1,216
2000	8000	$4,810,990	$2,405
2000	12000	$6,688,030	$3,344

All data derived from Tesla https://www.tesla.com/en_AU/powerpack/design#/, March 2017

As

Figure 9 shows, the cost per KW has a near linear relationship[8] with the energy storage for a given power output, and reducing the energy storage will reduce the cost significantly. While Tesla do not currently offer anything below a two hour configuration, it may be assumed that if sufficient demand arose for such configurations, they would be added. There is no technical reason why the cost reduction would not follow

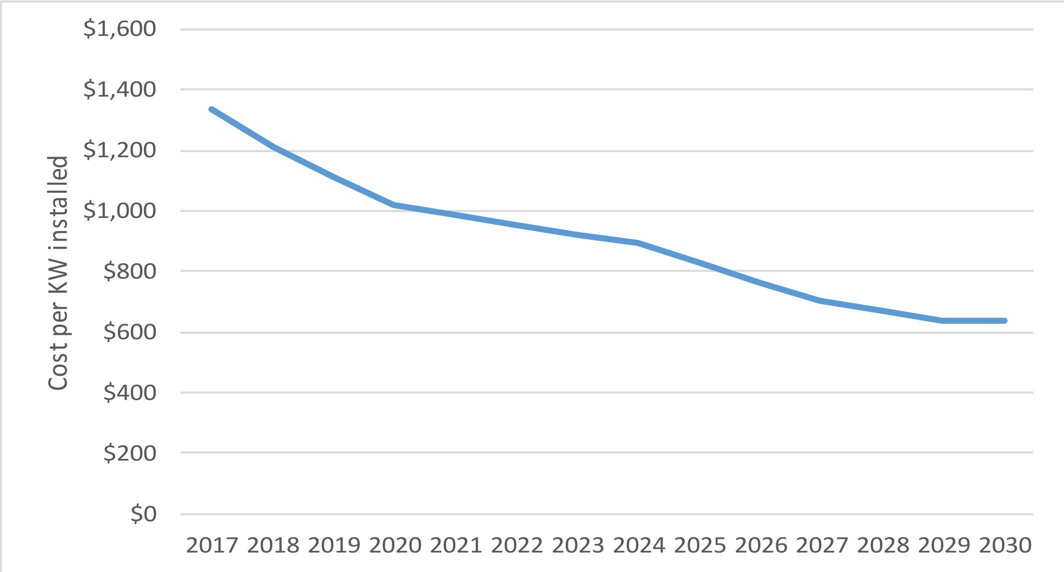
[8] $y = 527.11x + 220.52$, $R^2 = 0.9958$

the same curve, in which case a 1 hour utility battery would have a base cost in 2017 of $748/kW, rather than $1216/kW.

As the 0.5 hour and 1 hour configuration is not currently available, this report takes a conservative approach and uses the cost for a 2 MW, 2 hour battery as the input for cost calculations for utility batteries, while acknowledging that these are the upper bound of cost, and that this could be reduced by 60% if a 0.5 hour battery becomes available. Allowing an additional 10% for shipping and installation, this comes to Au$1,338/ kW at 2017 prices for a MW scale 2 hour battery.

Using the cost decline from Brinsmead, et.al 2016b discussed in Section 2.3.1, the price projections for 2030 were calculated. This gives a price of Au$637/kW for 2030. However, given the speed at which the Li-Ion market has been changing, it has become increasingly difficult to provide price projects for a period greater than the next two years.

Figure 10: Price per kW projection for a 2MW, two hour battery in AUD$



Price includes 10% for shipping and installation.

3 POLICY AND REGULATION

3.1 Objectives of energy storage policy

The roles of policy intervention in the energy storage industry are: to promote a strong domestic marketplace while protecting the interests of consumers, and to maximise benefit and minimise detriment. If the current market is not able to accommodate new energy storage technology in efficient and/or effective ways, then government policy is needed.

Australia's energy sector is not easy for new entrants. It is inherently and necessarily complex, given the regulatory structures in place to govern a dis-integrated market structure. While the industry is becoming more competitive with more retail offerings and the privatisation of more network businesses, there is still substantial resistance to change in the industry. Thus, it is still far from an easy environment to test new ideas quickly and dynamically, as is needed for storage technologies and value models. There may be a role for government to incentivise the development of these ideas, reducing the risk for traditionally risk-averse businesses, and helping direct investment towards the best long-term storage mix to provide the suite of services our future energy market will need.

While it is not within this study's scope to recommend specific policies, since new policies must be the result of a consultative process based on a set of objectives agreed by the government, this section seeks to distil the most pertinent issues for energy storage policy in Australia. For instance, as shown in Section 2 above, not all storage technologies provide the same level of service. Some will deliver the energy needed but cannot provide the network support services to accommodate the inertia need, and some effectively deliver the inertia needed but have a high cost of energy. This section investigates the current environment for energy storage in Australia, identifies the potential distortions that could affect storage development and uptake in the market, and puts forward a case for key elements of the storage market that could be positively influenced through well-designed policies.

3.2 Today's environment for storage

It is critical to understand the market landscape prior to embarking on policy action to ensure that measures address the barriers to an industry while also capitalising on growth opportunities. For this study, we have used a traditional SWOT analysis to interrogate the current internal (strengths and weaknesses) and external (opportunities and threats) environments for energy storage in Australia. This is a preliminary analysis, based on available literature, the findings of the model and anecdotal experience, and we suggest that the conclusions be tested broadly with energy sector stakeholders following the conclusion of the study. Each element is discussed in detail below and summarised in Figure 11.

3.2.1 Strengths

The key strength of storage is the broad range of services it can offer at a competitive price, particularly as battery cost curves decline rapidly. Given the exuberant customer interest in battery storage (the 'Tesla effect') and our strong research expertise, there is a chance for Australia to become a global leader in energy storage applications.

Technology development

- Energy storage, particularly batteries, has the potential to provide a wide range of network support services, which will become more prevalent due to the introduction of new inverter standards (AS4777) in October 2016 (CEC 2016).
- The costs of many energy storage technologies are rapidly declining to become more competitive for a wider range of applications e.g. the cost of Li-ion batteries fell 11–24% in 2016 (Roselund 2016)
- Australia hosts world-leading expertise in new energy storage technologies including the University of Wollongong's Institute for Superconducting and Electronic Materials, the University of Technology Sydney's Centre for Clean Energy Technology, the University of South Australia's Thermal Energy Storage Group and the CSIRO.

Deployment conditions

- Australia's expansive renewable energy resources, coupled with the large distances covered by the NEM, provide optimal conditions for energy storage deployment.
- Many businesses are trialling new energy storage applications across the NEM, and this is providing a deep knowledge base for future deployments e.g. the ARENA-funded Australian Energy Storage Knowledge Bank hosted at the University of Adelaide (University of Adelaide 2017).
- Consumers are enthusiastic about installing battery storage solutions, with interest peaking as Tesla enters the Australian market.

3.2.2 Weaknesses

As with any developing industry, there are still many technological and economic risks that affect the successful uptake of some energy storage solutions. These weaknesses will hamper the uptake of technologies if they are not appropriately managed.

– **Technology risk**

  - Not all forms of storage are equal and no one storage technology is likely to service the complete range of applications required by the market e.g. providing the complete market need for generation and inertia support (Cavanagh et al. 2015).
  - New storage technologies, such as novel hydrogen production and battery chemistries, are largely untested for long-term performance and reliability. In addition, there are currently competing safety standards and accreditations for battery deployment. This adds to consumer uncertainty and has the potential to hinder market growth (Fleming et al. 2017).
  - Some storage technologies, in particular pumped hydro, require a long development time and long-term planning thus may not be available to respond to an urgent need, even if they are the cheapest option.

– **Accessing the value stack**

  - The cost of deployment is often far higher than the costs implied by energy storage marketing – balance of system (BOS) elements can contribute more than half the cost of the total system (Trabish 2016). This is driven by: the novelty of the technology; the challenge to integrate control systems with the electricity network that has limited experience with new Internet of Things (IoT) systems; and the difficulty working with international companies who are not familiar with Australian conditions.
  - Although new storage technologies offer a suite of new functionalities, the value for these is not well understood. It is unclear how much providers should be compensated for elements of 'the value stack', and this makes it challenging to build a business case.
  - These value propositions, and how they are accessed by businesses, are still developing, and are strongly tied to the regulatory system, which was not originally designed for DERs. There are still many barriers to entry, such as the 1MW threshold for market participation. These barriers prevent new entrants from testing their business models, and as a result they slow the market's development.

3.2.3 Opportunities

Storage has been heralded as the essential stepping-stone to meeting our climate targets without compromising electricity reliability and affordability. Energy market reform and innovation funding may offer new opportunities for storage developments. For example Australia may be uniquely positioned to become a renewable energy exporter through novel storage technologies such as hydrogen.

– **Helping Australia meet its emission reduction targets**

  - As the penetration of variable renewable energy generation increases, there is likely to be a greater need (and greater demand) for back-up generation and inertia support services. Energy storage is likely to be an attractive option, as it is likely to emit less CO_2 than diesel and gas-fired competitors.

  - The opportunity for the growth of a storage market will be larger if complementary renewable energy policies are expanded e.g. an increasing Renewable Energy Target from 2020 and further ARENA funding for innovation.

– **New energy market opportunities**

  - There are already new opportunities available to use storage technologies that can provide ancillary services to the market (AEMO 2015), which will help drive access to multiple streams of value. For example, distributed batteries connected to the grid by 'smart' inverters that comply with the new A4777 standard have the ability to help regulate voltage and frequency, and commercial scale installations may be able to provide "black start capability".
  - The implementation of cost-reflective pricing (AEMC 2014), and other future tariff reforms, are likely to provide greater opportunities to generate value from energy storage and thus, are expected to drive further uptake.
  - There is expected to be further and widespread energy market reform to accommodate the "technology revolution" across the electricity network and the AEMC has initiated its strategic priorities review for energy market development (AEMC 2017).

– **Australia as a renewable energy exporter**

  - There may be an attractive prospect to develop a hydrogen export industry, likely in Western Australia e.g. produced by electrolysis with solar energy, then shipped compressed, liquefied or in the form of ammonia.
  - Establishing a hydrogen industry may bring down the costs in the local supply chain and develop an experience base that could make hydrogen storage cost-effective in the domestic market, including on the east coast.

3.2.4 Threats

The threats to the development of energy storage in Australia are largely driven by the changing energy market and regulatory complexities that create barriers to entry. In addition, resource availability may well limit the deployment of technologies in the short and long terms.

– **Policy and regulatory risk**

  - Converse to the opportunity identified above, if Australia's renewable energy policy is not prioritised and the generation mix remains as it is today, then there will be no additional need for energy storage in the market. This is considered unlikely given our international emissions reduction commitment.
  - While energy market reform may open up new value streams, it may also limit the application of new technologies or business models e.g. the electricity ring-fencing guideline (AER 2016) released by the AER in 2016 limits network ownership of behind-the-meter assets such as residential batteries.

– **Market development issues**

  - Unexpected market impacts of energy storage could change the energy mix in unhelpful ways e.g. energy storage could out-compete gas generation as a fast responding supply, which may reduce system adequacy by pushing existing gas generation out of the market and inhibiting investment in more.
  - A large driver of new storage technology uptake is likely to be consumer demand, and this will be influenced by the experience of early adopters. If performance does not meet expectations, particularly payback periods, future demand may be lower than anticipated.

– **Resource constraints**

  - Land-use issues and resource availability may limit the potential deployment of some technologies or escalate their price e.g. Australia's drying climate may prevent applications of pumped hydro in certain locations, and the supply of certain essential elements, such as lithium, may not meet future demand (this is considered in more detail within work programs 2 and 3)

Figure 11 Summary of SWOT analysis for energy storage

STRENGTHS Technology development: a broader range of services available at rapidly decreasing costs, supported by Australian expertise Deployment conditions: the potential for Australia to build a comparative advantage in energy storage	**WEAKNESSES** **Technology risk:** not all storage is equal and the market may not deliver the required services **Accessing the value stack:** the difficulty accessing the gamut of value streams, particularly while Balance of System (BoS) costs are still high
OPPORTUNITIES Helping Australia meet its climate targets: providing low-emission support for variable renewables New energy market opportunities: energy market reform will drive new business models Australia as a renewable energy exporter: the potential to develop a hydrogen export industry in WA	**THREATS** **Policy and regulatory risk:** unsupportive energy policy and/or market reform may hamper market development **Market development issues**: distortions promoting an inefficient storage mix **Resource constraints:** land-use issues and resource availability limiting certain technologies

3.3 Promoting growth and managing risk

Given the internal and external environmental factors, it will be important for energy storage policy to promote market growth (capitalising on strength and opportunity) while also managing risk (mitigating against weakness and threat). Table 11 recommends the key elements that government should consider when developing policies for an efficient and effective energy storage market.

Table 11 Policy considerations based on SWOT analysis

POLICY FOR GROWTH	POLICY FOR RISK
Promote an energy storage mix that meets Australia's near-term and long-term system needs, and supports our climate targets	Consider intervening when the market is not promoting investment in lower-cost technologies with longer lead times
Pursue timely energy market reform to create a competitive marketplace for new technologies, services and business models	Respond to changes in renewable energy policy to ensure that the expansion in variable generation does not adversely impact electricity reliability
Explore the potential for Australia to build a comparative advantage in both research and deployment of energy storage	Monitor the resource availability for the proposed energy storage mix and consider options for alleviating this risk e.g. lithium recycling
Explore the potential for hydrogen to provide Australia with the capability to export renewable energy to the Asia-Pacific region	Promote knowledge sharing amongst the industry with regards to research and deployments that are supported by government e.g. lessons learned through ARENA-funded battery storage demonstrations to reduce BoS costs for future projects

	Monitor any flow-on impacts of energy storage uptake to other technologies in the energy mix, particularly gas generation, and ensure this does not adversely impact system reliability

4 METHODOLOGY

4.1 Overview

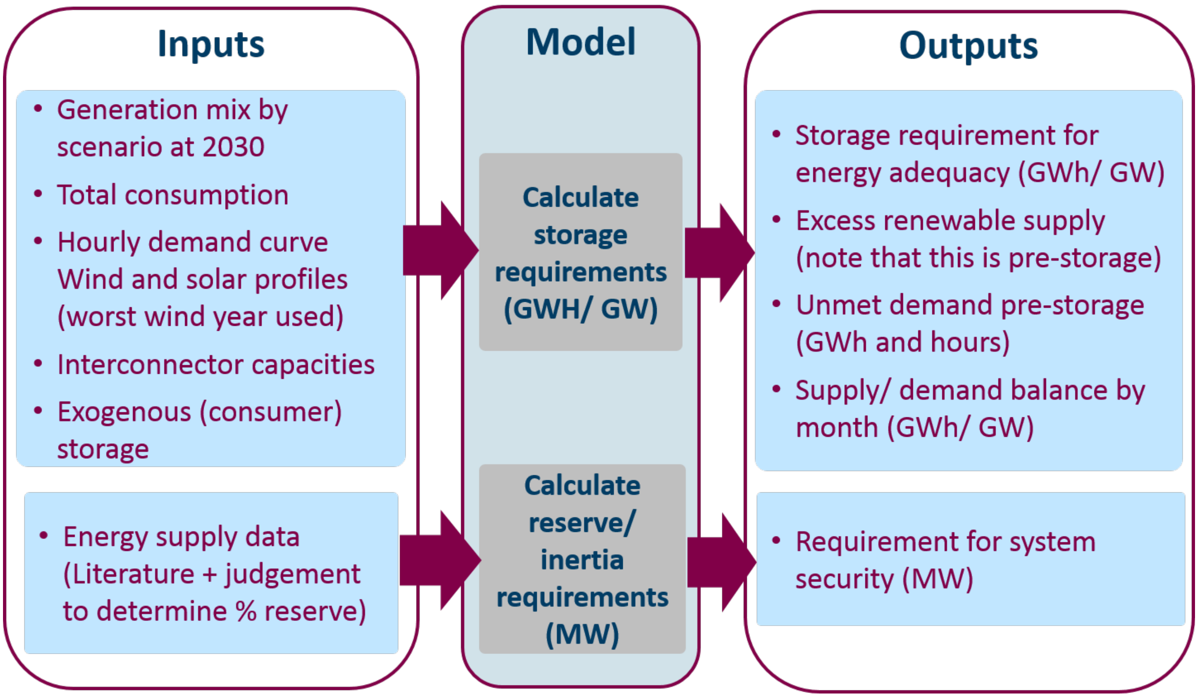
A storage analysis model has been developed specifically for this study from the UTS model developed for analysis of generation and storage needs for a microgrid on Kangaroo Island (Dunstan et al., 2016). That model was developed from the RE24/7[9] grid analysis tool that uses the commercial MESAP/PlaNet.

The key objective of the modelling is to calculate the theoretical storage requirement for energy adequacy, which is the storage required to ensure there is sufficient energy to meet demand. The framework is an hourly resolution, and storage is to ensure that there is sufficient energy to last through those days where there is low output from variable sources.

Hourly inputs are all for 2010, which was chosen from a limited databased of 7 years (2004 – 2010 inclusive), on the basis of the longest continuous period of low wind output. It was assumed this would result in the greatest requirement for energy adequacy storage, as an extended period of low wind output in a system with high wind penetration could potentially mean multi day storage is needed. Figure 12 provides an overview of the storage calculation process. Key inputs are:

- The generation capacities by type for the three scenarios (business-as-usual, Paris compliant, and a high renewable mix);
- Demand projections and load curves for each state;
- Interconnector capacities; and
- Meteorological data to calculate solar and wind power generation at an hourly resolution.

Figure 12 Storage calculation – overview



The installed capacities are derived from published sources, while the resulting annual generation in MWh is calculated on the basis of meteorological data (in case of solar and wind) or dispatch requirements. Section 5.4 provides detailed information about all input parameters.

The model does not include possible intra-state restrictions due to transmission or distribution constraints, so it is assumed generation anywhere in a state can meet demand anywhere within that state. Potential

[9] RE24/7 is based on PhD thesis by ISF Research Principal Dr Sven Teske (Teske, 2015).

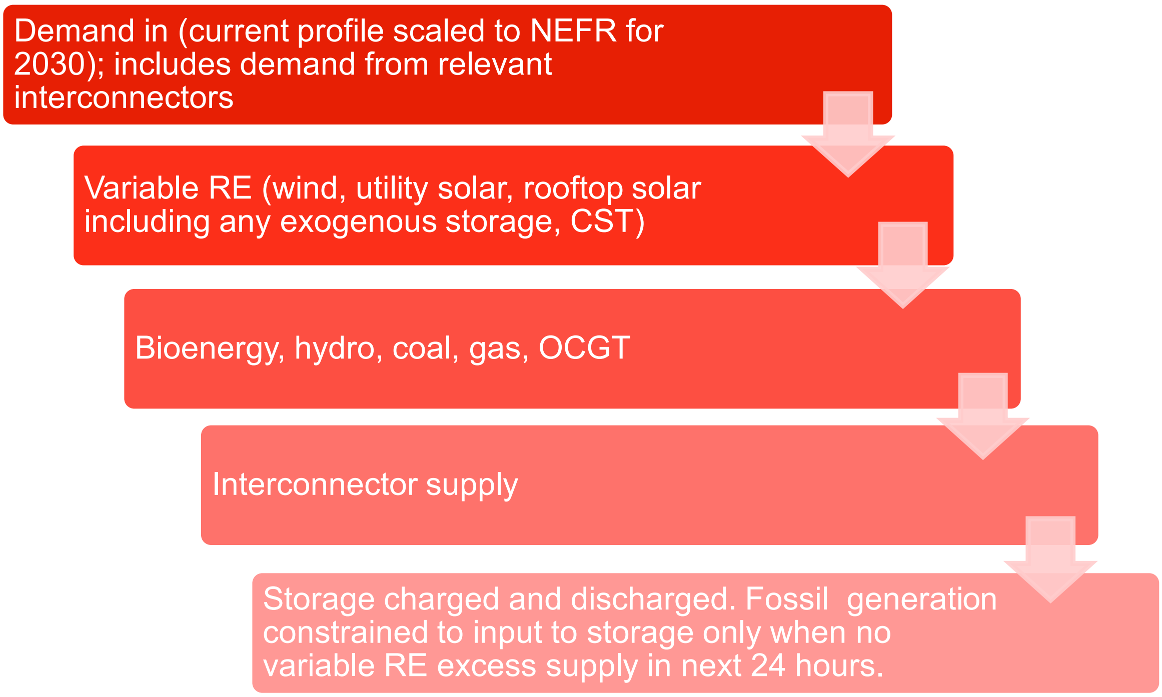
export via interconnectors is limited by the capacity of the interconnector, and is only allowed if all demand is within the state is met.

The model identifies excess renewable production, defined as potential wind and solar photovoltaic generation greater than the actual hourly demand in MW during a specific hour. In order to avoid curtailment, the surplus renewable electricity must be exported via an interconnector, or stored in some form of electric storage technology.

Within the model, excess renewable production accumulates through the dispatch order. If storage is present, it will charge the storage within the limits of the input capacity. If no storage is included, this potential excess renewable production is reported as "potential curtailment" (pre-storage). It has been assumed that a given amount of behind-the-meter consumer battery storage will be installed, independent of system requirements.

All scenarios have been calculated with the same dispatch order to achieve comparable results, shown in Figure 13. Storage (apart from exogenous consumer storage) is set as the last supply technology in order to calculate both the 'unmet demand' and the storage requirement for energy adequacy. Note that this is not the same as the storage requirement to prevent renewable curtailment, or the requirement to provide system security.

Figure 13 Storage model – dispatch order



4.2 System security

The inertia provided by large spinning masses in steam and gas turbines is steadily decreasing in Australia's power system, and in others worldwide, as the share of variable renewable energy generation increases. Potentially, this can reduce a system's ability to maintain frequency for long enough to respond to sudden changes in electricity generation, transmission, or demand. A preliminary analysis in this report estimates the point at which this may become a problem, and suggests the amount of battery energy storage that would be needed to address the problem.

This presumes that batteries are the preferred solution, and that they are capable of providing the necessary fast frequency response. Large battery systems are already used for frequency regulation, for example, a 49-MW lithium-ion battery system will be commissioned in 2018 to provide sub-second frequency support in the UK grid (Berlin Adlershof 2016) and millisecond responses are anticipated for battery technologies in the engineering literature (Lucas and Chondrogiannis 2016). Australian company Ecoult has supplied a 3-MW advanced lead-acid battery system for frequency regulation in the PJM grid in Pennsylvania (East Penn Maufacturing Co 2014) – and response times of 50 milliseconds are reported for another project. Fast-responding battery systems are used to manage supply-demand variations in several remote power systems in Australia, such as the recently commissioned De Grussa mine (ARENA 2016).

There are other means, such as using renewable energy generators that use synchronous turbines, including hydro, concentrating solar thermal, and biomass generators, as the number of fossil-fuel powered turbines decreases. With the right selection of turbines, hydro generation and pumped hydro storage can be operated in “synchronous condenser” mode to provide inertia with only a small water flow. Wind turbines also have inertia in their spinning blades, and even though their rotation is not synchronised with the grid frequency, this inertia can be accessed through the control system as “synthetic” inertia (Seyedi and Bollen 2013). This is well-established technology: in 2005 Hydro-Québec TransÉnergie was the first grid operator to mandate this capability from wind farms, and inertia-compliant wind turbines manufactured in Germany now account for two-thirds of Quebec’s wind capacity (Fairley 2016). Brazil and Ontario are also now requiring this capability (DGA Consulting 2016).

It’s important to understand that inertia isn’t a fixed quality of a power system: it is highly dynamic depending on the real-time generation mix. dequacy requirement is examined.

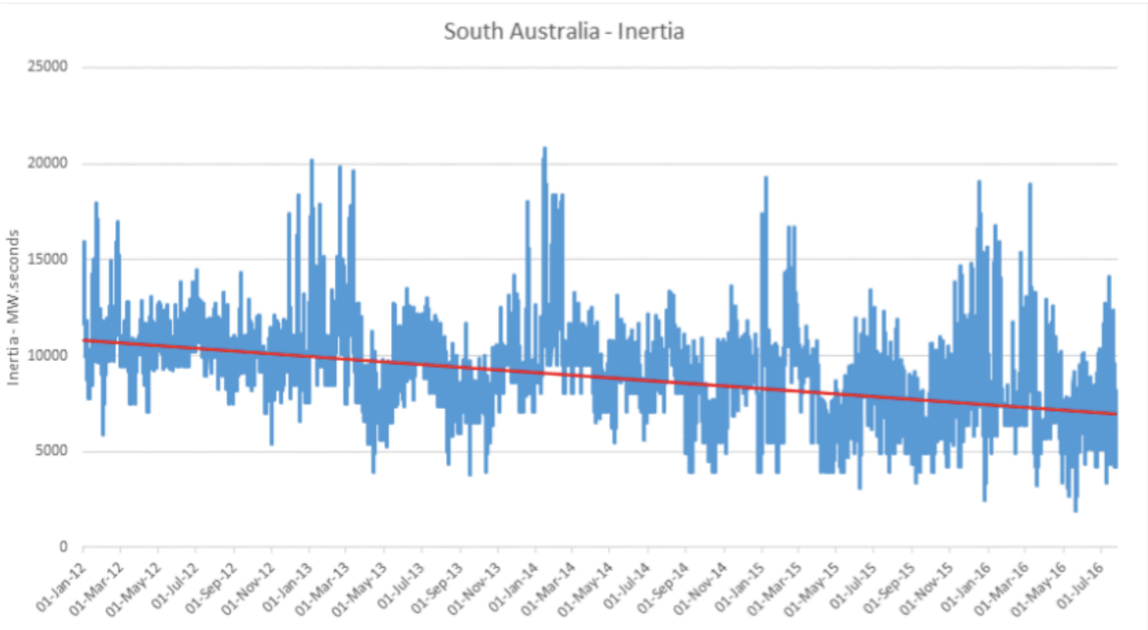
Figure 14 from AEMO (2016c) shows the inertia in South Australia trending downwards overall but fluctuating greatly by a factor of 10 during 2016. The blackout in September 2016 occurred at a time when there was a particularly low inertia due to transmission line failures, and high reliance on wind energy and on the interconnector from Victoria. This low inertia resulted in a rate of change of frequency (RoCoF) of 6-7 Hz/s. Anything greater than 0.5 Hz/s is regarded as a high rate of change, and RoCoF should generally be kept below 1 Hz/s, which is the default standard for generators connecting to the NEM. A full assessment of the tolerance for RoCoF of generators in the NEM is yet to be done, but has been completed for the Irish grid, which like South Australia has a high level of renewable generation, and the finding is that a RoCoF of up to 1 Hz/s is tolerable but undesirable (DNV KEMA 2013). Very few large international jurisdictions (500 MW or more) are experiencing issues related to high RoCoF, so Ireland and SA are pioneers in managing this aspect of the transition to renewable generation (DGA Consulting 2016).

High RoCoF causes large generators to disconnect because they cannot follow the change, or would be damaged if they attempted to do so, which leads to loss of generation and sometimes to system collapse. All thermal of generators in the Irish grid were found to be unable to remain stable at a RoCoF of 2 Hz/s (DNV KEMA 2013). The underlying technical challenge is managing frequency deviations, and inertia provides a means to do this but not necessarily the only means (AEMO 2016d). A Fast Frequency Response (FFR) is defined as a rapid active power injection to arrest the frequency decline following a contingency event. The response time to replace inertial responses to RoCoF should be 1-2 seconds or less; by comparison, the fastest response provided by existing FCAS in the NEM is 6 seconds, and it’s noteworthy that redesigning the FCAS markets is currently under consideration by AEMO.

Inverter-connected devices such as battery energy storage are already providing cost-effective FFR through the rapid switching capabilities of their power electronics (Tesla Motors 2017b). Storage technologies are becoming the dominant technology for delivering fast regulation services in the PJM Interconnection in the US, and were the primary technology selected in a recent UK tender for fast frequency services. Managing power system security using FFR alone, without any physical system inertia, is a research topic in the international literature (Tielens and van Hertem 2012), and may become possible in future by using inverter-connected devices (AEMO 2016c). Meanwhile FFR is a near-term solution to power system security under conditions of reduced inertia.

There are numerous studies in the literature (Bevrani, Ghosh, and Ledwich 2010; Denholm and Hand 2011; Nguyen and Mitra 2016) that model and discuss frequency regulation when there is a high penetration of renewable energy sources, but only recently are contingency requirements being modelled in a quantitative way (Arteaga 2016). Therefore, this report estimates the FFR requirement for system security by considering the amount of synchronous generation per state, compared to the total generation capacity, at present and for the three 2030 energy mix scenarios, identifying where there is potential for high RoCoF. This provides an approximate indication of the amount of FFR that should manage this issue – and most likely it overestimates the true requirement that would be obtained through a detailed study of power system dynamics. This is interpreted as a requirement for battery energy storage power capacity (GW) and the potential for this storage to also contribute to system adequacy requirement is examined.

Figure 14 Variability of system inertia in South Australia 2012-2016



4.3 Unmodelled storage

The aim of this study is to assess energy storage requirements for power system reliability, and the capabilities and costs of technology options to meet the requirements. This is in the context of other uses for energy storage for customer applications, network applications and generator applications including off-grid systems. For example, it is anticipated that there will be a large amount of residential energy storage by 2030 and this is not explicitly modelled as reducing the requirement for new energy storage. It should however be taken into account when considering how to meet the requirement.

Energy storage installed for other uses will be considered as potentially available to meet a storage requirement for power system adequacy or security.

While electric vehicles are likely to create considerable energy demand by 2030, they automatically come with storage. Provided their charging regimes are managed to some degree, their impact on energy supply and additional energy storage requirement may be ignored to a first level of approximation. Nevertheless, it should be borne in mind that major manufactures are designing grid-support functions into their future electric vehicles and charging stations.

4.3.1 Northern Australia

It isn’t sensible to examine northern WA and the NT using the same modelling method as the other states, because electricity generation in these regions is dominated by gas and diesel and there will be limited demand for storage to provide system adequacy for the foreseeable future, for supplying local loads. Many loads in this region are for mining developments which increasingly use hybrid power systems combining fossil fuel with renewable generation and energy storage. Such storage is used for system security of the local power system. However, these regions do not have large interconnected power systems and are not the focus of this study – no intervention is needed.

Nevertheless, there is an interesting opportunity to scale up the energy storage industry in Australia, alongside the development of a renewable energy export industry by one of the pathways being proposed. This may help to develop the supply chain of energy storage technologies which will benefit the interconnected power systems as well.

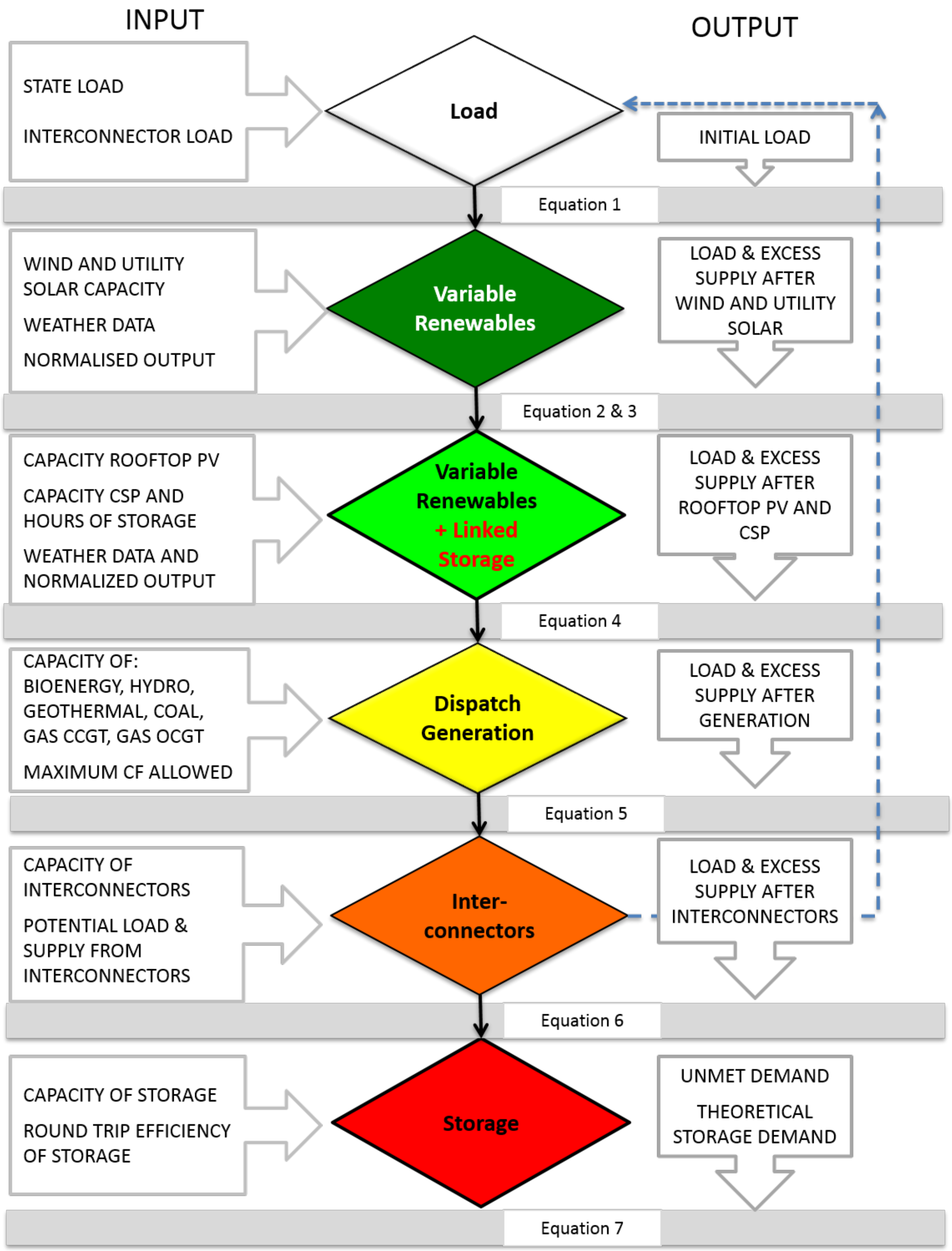
4.4 Model structure

Figure 15 shows the structure of the model, which is implemented as a spreadsheet with the calculations detailed below. The primary outputs of the model are the theoretical demand for storage by state, and the unmet demand prior to the introduction of storage technologies. The theoretical storage demand is defined as the minimum amount of storage which would result in zero unmet demand.

All calculations are done on an hourly basis for each hour of the year for each state, and the final results are the sum of the hourly outputs. Appendix 2 gives the equations used at each step of the calculations.

The key results are the unmet demand prior to storage, and the minimum energy storage (measured in MWh) which results in a zero value for unmet demand post storage.

Figure 15 Model structure



4.5 Limitations

The model is not a power system model of Australia's electricity grid, and cannot simulate consumer or generator behaviour. However, it does carry out an hour-by-hour calculation of the energy supply balance, and calculate the storage required to compensate for extended low supply periods. Key limitations are:

– The model does not take account of distribution or transmission constraints, so if there is variable renewable generation in the system, it can go into any utility scale storage in front of the meter, providing the storage is not fully charged.

– For those dispatchable technologies (namely hydro and bioenergy) where we impose a maximum capacity factor over the year, this is achieved by reducing the effective load continuously until that capacity factor is achieved. This mainly applies to hydro and bioenergy. This is a simplification, but would tend to increase any storage requirement that is found.

– Interconnectors can only connect one step (e.g. surplus wind from SA coming into VIC cannot supply NSW)

– In order to calculate the storage requirement, we have put storage ***last*** in the dispatch order. In the real world, storage is likely to overlap considerably with dispatchable generation, as increasing cycle numbers reduce LCOS. This means curtailment would be lower in the real world.

5 MODELLING INPUTS

5.1 Energy scenarios

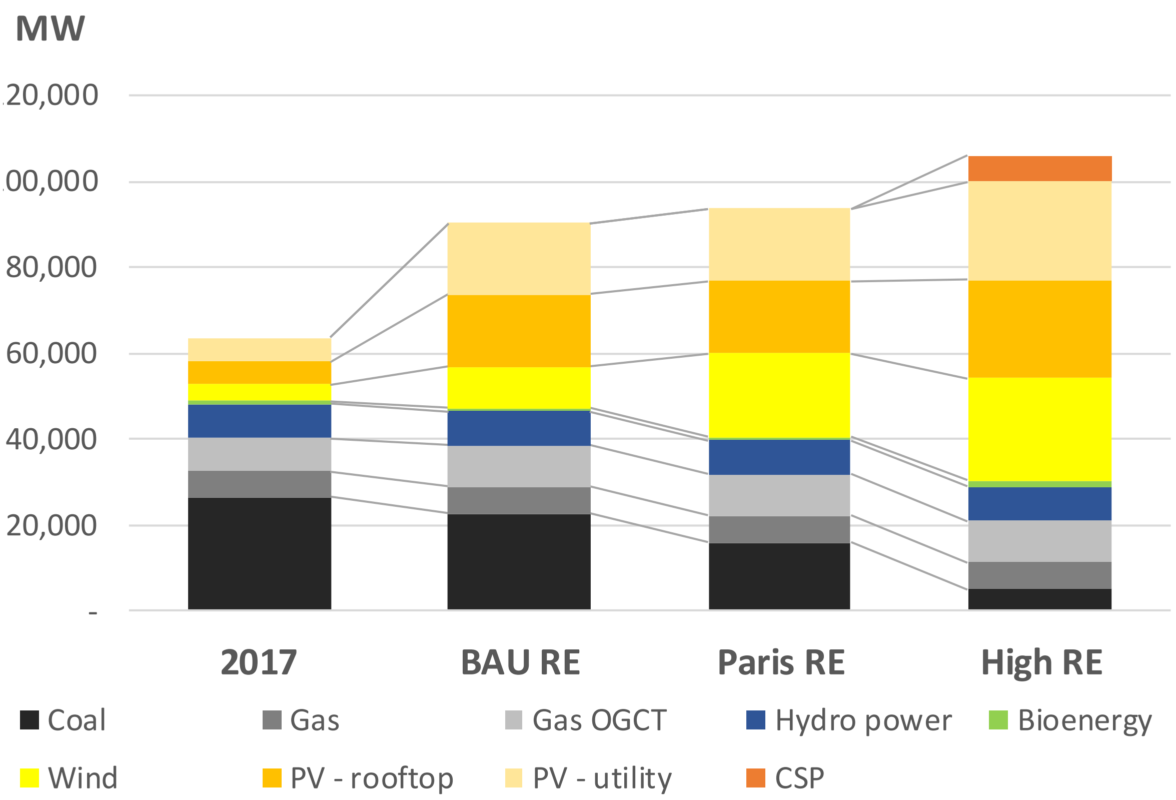
Storage requirements for a given demand profile are determined by the generation mix available, and in particular the proportion of variable sources such as wind and solar, compared to dispatchable sources such as gas, coal, hydro, or bioenergy. The energy adequacy requirement will be driven by the longest period of low variable renewable supply, while the security requirement will be driven by the ability of the specific generation mix to respond to and ride through frequency variation events.

The objective of this study is not to forecast the energy mix which may be in place at 2030, but rather to determine the range of storage requirements which may arise given possible energy generation pathways. Energy scenarios have been selected to explore the range of storage requirements, and do not represent either a least cost generation mix nor an optimum mix of generation and storage. One of the findings of the research is in fact that such an optimisation should be undertaken.

This study examined three energy scenarios, a “business as usual renewables” (BAU RE) scenario, a scenario with an energy mix compliant with Australia’s commitments made at the COP21 meeting in Paris (PARIS RE), and a high renewables (HIGH RE) scenario. The scenarios were chosen to provide an envelope of the potential storage requirements at 2030. The overall capacity mix by scenario is given in Figure 16. Capacities by state are shown in

Figure 18, and a full list is given in Appendix 4.

Figure 16 Total generation capacity by scenario in 2030



The input to the modelling is the capacity mix, which is as shown Figure 16; the amount of renewable generation is a modelling output, as it depends on both the hourly demand, and the dispatch order for the different generation types.

In the three scenarios the modelled output of renewable energy, including energy from variable and dispatchable sources, accounts for a minimum of 36%, 52%, and 76% of electricity generation at 2030 respectively. The proportion of renewable energy in the HIGH RE scenario would in practice be higher as a result of storage, which has not been modelled.

The BAU RE scenario is derived from the AEMO generation information for each state, including committed and proposed projects. In this scenario, it is assumed that 50% of proposed wind, solar, and gas projects go ahead, with the exception that in South Australia only the committed wind farms go ahead.[10] Announced withdrawals of a 3940 MW of coal plant are included. Appendix 3 gives the detailed information from AEMO which was used for the current energy mix and the BAU RE 2030 energy mix. Rooftop solar data for each state is taken from the National Electricity and Gas Forecasting report (Australian Energy Market Operator (AEMO) 2016b), using the neutral projection of installed capacity.

The PARIS RE scenario increases the penetration of renewable generation, and retires a number of coal fired generators, sufficient to meet the electricity sector renewable penetration in the lowest cost scenario in the Climate Change Authority report (Climate Change Authority 2016). This report reported a range of renewable penetrations from 46-76% corresponding to different policy options. Fifty-two per cent renewable generation was chosen as the likely outcome of an emissions intensity scheme, which the CCA identified as the lowest cost option, and this was taken as the target renewable percentage for the PARIS RE scenario. Note that for this scenario, the capacity mix was iterative until it resulted in a 52% renewable generation output.

The HIGH RE scenario uses the nationwide generation capacities from a projection of 100% renewable electricity undertaken recently by the UTS Institute for Sustainable Futures (Teske et al. 2016), modified to remove the capacity increase projected to cater for a rapid switch to electric vehicles.[11] Renewable capacities in that report were very much higher than they are in the current proposed projects, as would be expected, and coal capacity reduction exceeded the currently announced withdrawals. In order to arrive at a state-by-state allocation, the nationwide capacities per technology allocated in proportion to presently proposed projects, and then adjusted to distribute the resulting curtailment more equally between states. Coal retirements were scheduled such that the older generators would be retired first.

The operation of hydro generation is an important variable in the modelling, as hydro can operate as a peaking plant. The potential output was approached conservatively, as storage requirements should be assessed against the worst case. Thus, a maximum capacity factor of 20% was assumed for NEM states other than Tasmania, and 50% for Tasmania. The 20% corresponds to overall hydro output from 2010, which was a low year (Office of Chief Economist (OCE) 2016). The Tasmanian hydro maximum capacity factor was set at the minimum average annual capacity between 2011 and 2017 (Hydro Tasmania 2017).[12] The dispatch order in the model puts variable renewables ahead of hydro and bioenergy, so the actual capacity factor depends on the amount of variable renewables. In Tasmania the modelled capacity factor is less than 50% in the HIGH RE scenario.

[10] Energy mix data between states was revised after the first modelling runs, which resulted in an unrealistically high potential curtailment in South Australia in the HIGH RE scenario.
[11] This study has not included the storage and demand associated with electric vehicles, as discussed in Section 1.
[12] Detailed information is available for Tasmanian hydro from 2011-2017, which is not available in the other states.

Table 12 Modifications to AEMO data to achieve PARIS RE and HIGH RE scenario

	NSW	QLD	SA	TAS	VIC	SWIS [1]
Factor for gas and rooftop PV used to increase proposed projects (PARIS RE and HIGH RE)[1]						
GAS (inc OCGT)	0.5	0.5	0.5	0.5	0.5	0.5
NEFR neutral forecast for rooftop PV	1.15	1.15	1.20	1.15	1.15	1.20
Factor for wind and utiity PV used to increase proposed projects in the PARIS RE scenario [1]						
Wind	1.5	1.3	0	1.5	1.5	2
PV – utility	2.0	2.0	2.0	2.0	2.0	2.0
Factor for wind and utility PV used to increase proposed projects in the HIGH RE scenario [1]						
Wind	2.1	1.8	0	1.8	1.8	2
PV – utility	3.0	3.0	2.0	3.0	3.0	3.0
Additional capacity after scaled up proposed projects in PARIS RE scenario						
Utility PV						1200
Additional capacity after scaled up proposed projects in HIGH RE scenario						
CSP	2,500	1,500	0	0	1,000	1,000
Utility PV	5000	4000	0	0	2000	3000
Bioenergy	350					
Assumed coal retirements (in addition to currently announced withdrawals)						
Coal [2] (PARIS RE)	-1320	-3780	-	-	-1450	-874
Coal [3] (HIGH RE)	-6,840	-5,240	-	-	-4,630	-874

Note 1: Proposed projects for the SWIS include public information on projects in addition to AEMO data (see Appendix 3 for details)

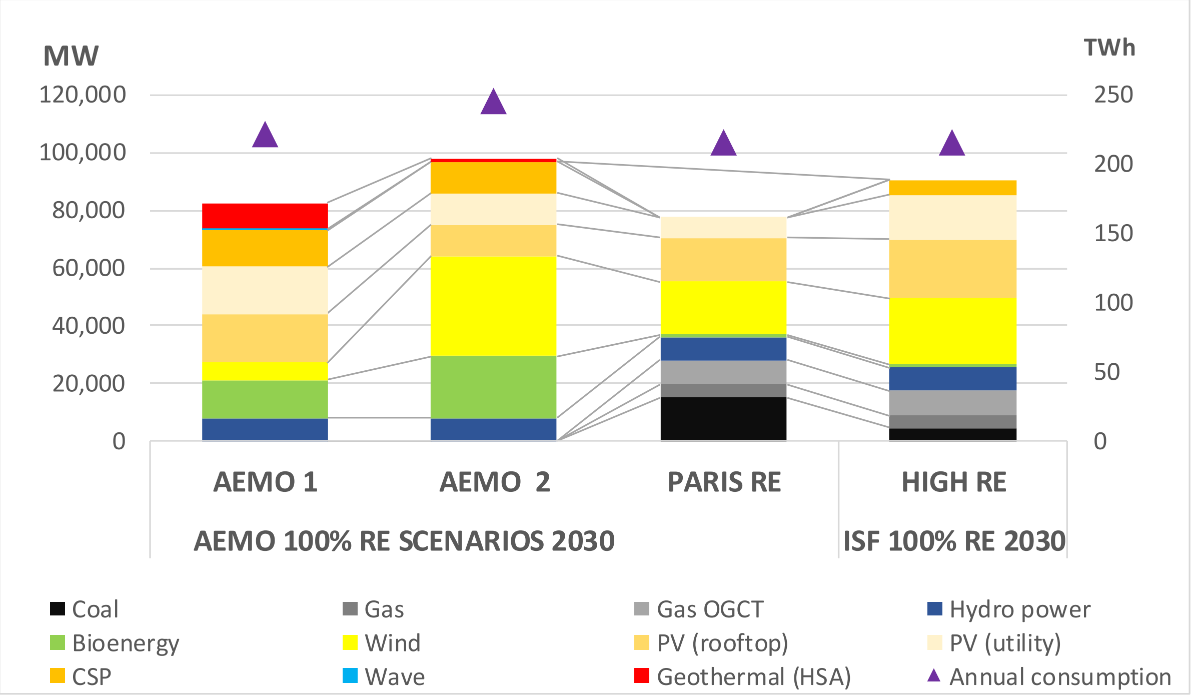
Note 2: A list of retired and remaining coal-fired power stations is given in Appendix 4.

5.1.1 Comparison with the AEMO 100% RE scenarios

In 2013, AEMO modelled two 100% renewable energy (RE) scenarios which projected a possible generation mix for 100% renewable electricity in the NEM, to be achieved by 2030 (Australian Energy Market Operator (AEMO) 2013). The generation mix reflected the LCOE estimates current at the time, and specifically examined how 100% renewable generation could be achieved. As such, no fossil fuel generation was included, and high priority was given to dispatchable renewable energy, specifically CSP, bioenergy and geothermal. From today's perspective, the likely generation mix is somewhat different, particularly taking into account the rapid drop in the cost of large-scale PV generation, which now begins to compete with wind generation. It is also unlikely that all fossil fuel generation would be phased out by 2030, even under an ambitious renewable scenario such as that envisaged in the 100% renewable electricity modelling undertaken by ISF (Teske et al. 2016).

Figure 17 shows the comparison between the capacity and annual consumption forecast in the two AEMO scenarios at 2030, and the HIGH RE scenario used in this study. Because the contribution from variable renewable sources is higher in the HIGH RE scenario, it is likely that the HIGH RE scenario would result in a higher storage demand than either of the AEMO 100% RE scenarios.

Figure 17 Comparison of PARIS RE and HIGH RE capacities with AEMO 100% RE



5.1.2 Energy scenarios by state

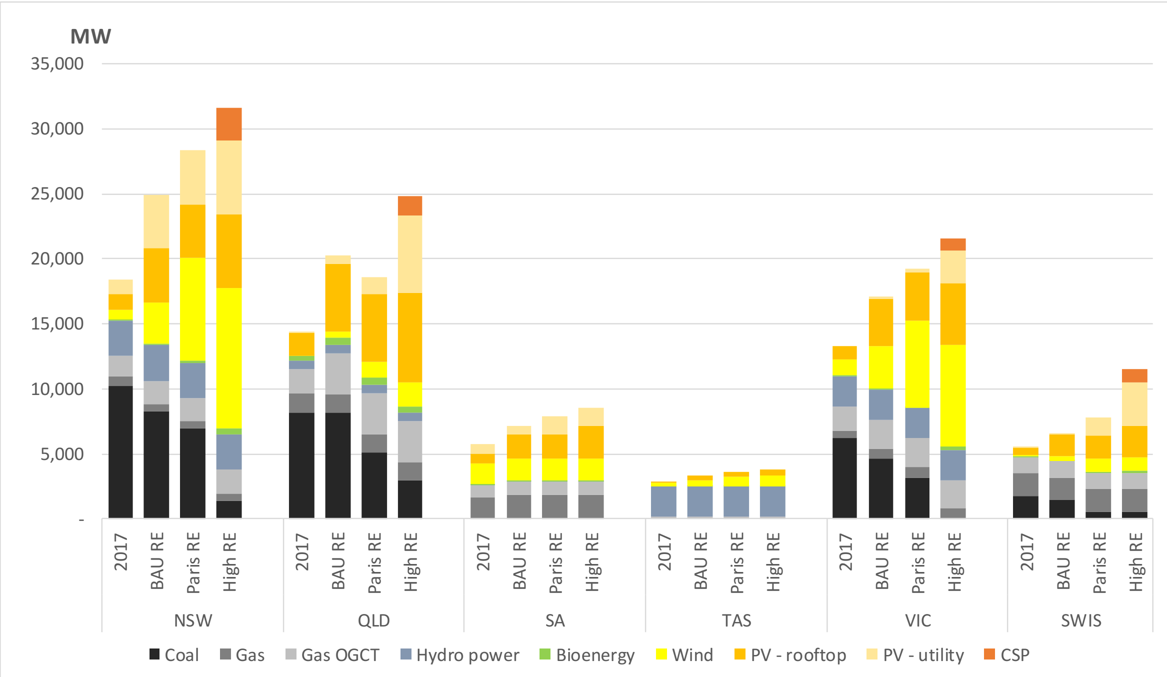
The generation capacity mix by state is shown for each scenario in

Figure 18 and given in detail in Appendix 4.

The BAU RE and the HIGH RE generation capacity scenarios result in renewable energy accounting for a minimum of 36% and 74% of total energy output respectively at 2030, with state percentages varying from 20% to 100% in the BAU RE scenario, and from 54% to 100% in the HIGH RE scenario.

The BAU RE scenario represents an increase from the legislated target of 20% renewable generation at 2020 to 36% at 2030, but falls short of some of the individual state targets, most notably Queensland's target for 50% of supply from renewable sources by 2030, and will not meet Australia's commitments made at the COP21 meeting in Paris. However, it is arguably a plausible scenario given the current policy uncertainty for renewable energy. To project from current generation mix and proposals for new generation to the modelling inputs, 50% of the proposed projects for gas, wind and solar were assumed to go ahead in the BAU RE scenario. As Queensland has a high number of proposed gas projects (2,545 MW) compared to other states, and a fleet of coal fired power stations built in the last 21 years[13], the renewable mix in the state remains low in this scenario.

Figure 18 Generation capacity - scenarios by state



5.2 Demand curves

Historical operational demand data was downloaded for each state from the AEMO website (AEMO 2016a, 2016b). The most recent half-hourly demand values were used, from the 2010 calendar year, averaged to give a total hourly demand. Projected 2030 demand was scaled up from the 2010 hourly profile, using the NEFR neutral forecast for operational demand in 2030. Current and 2030 consumption are shown in Table 13, along with the scale factor used to produce the 2030 demand curves for each state.

Table 13 Annual consumption 2016/17, 2030, and scale factor for 2030 demand

	NSW	QLD	SA	TAS	VIC	SWIS
2010 - AEMO historical data (GWh)	77,151	52,325	13,554	10,153	51,184	8,788
2030 - NEFR neutral forecast (GWh)	76,804	62,385	14,441	11,100	51,036	23,368
Factor	1.0	1.2	1.1	1.1	1.0	2.7

[13] These power stations include: Stanwell, 1996; Callide C, 2001; Millmorron, 2002; Tarong North, 2003; Kogan Creek, 2007.

5.3 Interconnector data

Interconnector capacities were taken from the AEMO 2015 report on interconnector capabilities (Australian Energy Market Operator (AEMO) 2015) and are summarised in Table 14. These capacities include currently planned augmentation. Some interconnectors have minimum and maximum capacities. The capacity of the NSW–Victoria link is sometimes limited by the output of the Murray and Tumut power stations in the Snowy Hydro scheme. As these power stations have been modelled with an effective capacity factor of 20%, it is reasonable to use the maximum value of capacity to model this interconnector. On the other hand, the minimum value of capacity is used to model the NSW–Queensland link as a conservative assumption. Where two interconnectors exist, they have been treated in the model as a single interconnector with their summed capacities in each direction.

Table 14 Interconnector capacities (highlighted values used in model)

	Minimum		Maximum	
NSW – Qld interconnectors				
	NSW to Qld	Qld to NSW	NSW to Qld	Qld to NSW
Terranora interconnector (N-Q-MNSP1)	107 MW	210 MW	107 MW	210 MW
Queensland to New South Wales Interconnector (NSW1–QLD1)	300 MW	1,078 MW	600 MW	1,078 MW
Total	407 MW	1,288 MW	707 MW	1,288 MW
NSW – Victoria interconnectors				
	NSW to Vic	Vic to NSW	NSW to Vic	Vic to NSW
Vic1 – NSW1	400 MW	700 MW	1,350 MW	1,600 MW
Victoria – Tasmania interconnectors				
	Tas to Vic	Vic to Tas		
Basslink (T-V-MNSP1)	594 MW	478 MW		
South Australia– Victoria interconnectors				
	SA to Vic	Vic to SA		
Heywood Interconnector	650 MW	650 MW		
Murraylink (V-S-MNSP1)	200 MW	220 MW		
Total	850 MW	870 MW		

5.4 Wind and solar data

The output from variable renewable energy sources is a key determinant of the storage required to ensure system adequacy; that is, the amount of storage needed to ensure there is enough generation or stored energy to meet demand at all times. This study analyses supply and demand for every hour in a one-year period, in order to explore daily and seasonal variations. Inter-annual differences in variable renewable resources can also be significant however, particularly for wind energy. There may be calm periods with little or no wind generation extending over a week or more, driven by the passage of large synoptic systems across Australia. Solar energy, in contrast, has a predictable seasonal variation between summer and winter, and is unlikely to have extended periods of low generation outside this pattern. The inter-annual variability of wind energy is thus greater than that of solar (GE Energy 2010; Widén et al. 2015).

To model the storage requirement for system adequacy, the year with the most extended period of low wind output was selected from the available data set for wind energy. Because solar irradiance is influenced by the same weather systems that determine the wind, solar energy output may have some correlation with wind energy output, so the same year of data was used for both resources to ensure that the model did not ignore any such correlation.

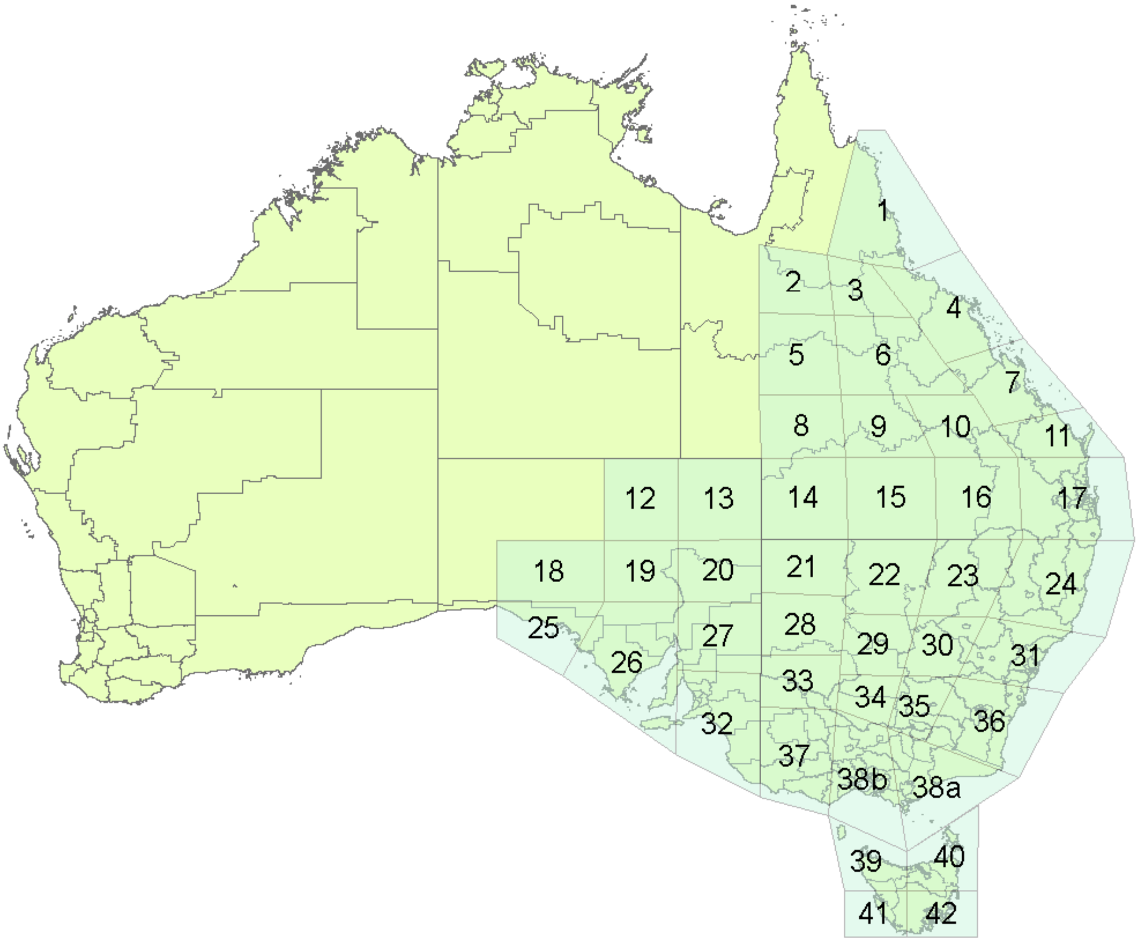
5.4.1 Onshore Wind, Utility Solar and CSP - NEM

The basis of the onshore wind and utility solar data for the NEM was the AEMO 100% Renewables Study (Australian Energy Market Operator (AEMO) 2013). ROAM Consulting (ROAM) was commissioned by AEMO to model potential wind and solar output to be used as input data for AEMO's modelling (Cutler et al. 2012). The work was published in 2012 and included, amongst other data, hourly output traces for a megawatt of installed utility-scale solar PV, a megawatt of solar CSP and a megawatt of onshore wind generation. These were calculated from meteorological data for generators at realistic locations in 43 polygonal regions across the NEM from July 2003 to June 2011. The method by which ISF chose the data set for the wind and solar data from ROAM's raw data is detailed below.

Figure 19 displays the 43 polygons used to subdivide the NEM. In addition to hourly time series, a build limit was estimated for each polygon, representing the maximum installable capacity for the region (allowing for geographical and land-use constraints), and the land area required for the maximum capacity.

To find an average output for each state by year, the traces were weighted by the build limits of each polygon and then an average was taken. In this way, more weighting was given to the regions more likely install PV, CSP or wind. See Appendix 5 for the weighting of polygons by state.

Figure 19 Polygons for renewable generation data developed by ROAM



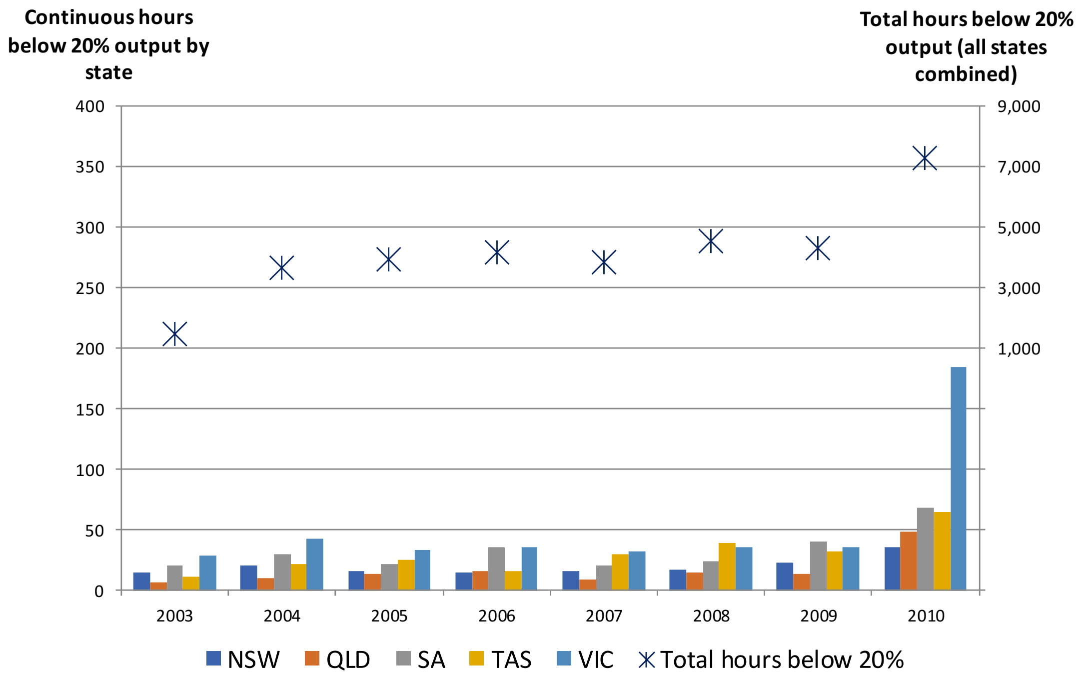
5.4.2 Determining the worst year for wind

Unfortunately, it was beyond the scope of this study to analyse a long time-series of weather data to identify the worst year for wind, and the data set chosen was only complete for seven years (2004 – 2010 inclusive). It would be prudent to extend the study to include a much longer dataset for weather years, and to include modelling of years with extreme heat waves.

Once the average traces were calculated for each state, the single year in the period 2004 to 2010 with the most extended period of low wind output was chosen (2003 and 2011 were not used because only half of each year was available). This was done by calculating the longest period for which wind output was lower than 20% of the rated capacity. As can be seen from Figure 20, 2010 had the longest period with very low wind output for all states, and was exceptionally poor in Victoria, with 184 consecutive hours below 20%.

In addition to the longest period of consecutively low output, the total number of hours per year with output below 20% rated output was calculated. Again, 2010 was the worst year in this respect, with the largest number of low output hours for every state, as depicted in Figure 20.

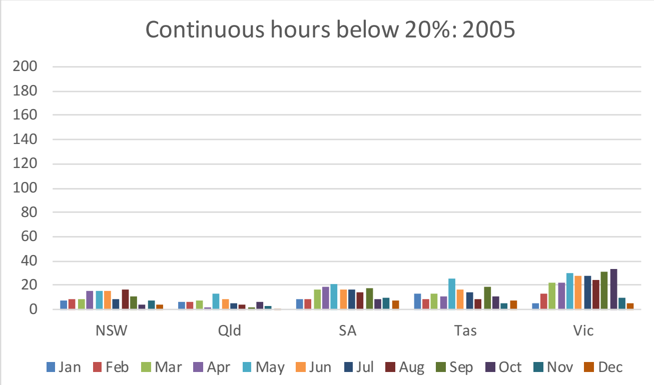
Figure 20 Consecutive hours of low wind production and total low wind hours



5.4.3 Heat waves

This study did not include modelling extreme heat wave years, as the year with the most protracted periods of low wind output within the dataset (2010) was not such a year. However, the full dataset did include two years with extreme heatwaves, 2005 and 2009 (Australian Government Bureau of Meteorology 2010), so the data was reviewed to see whether these heatwaves corresponded to low wind output.

Figure 21 shows low wind output for each month of the year, by state, for the two extreme heat wave years and for our study year (2010). Low wind output is shown in terms of continuous hours below 20%, and total low wind output hours per month. As may be seen, the highest number of low wind output hours occur in winter in every state except Queensland, and this is consistent in both heatwave years. Figure 21 also shows total wind outuput (normalised to a 1 MW turbine) per state for the three years. Once again, low wind output occurs in autumn and winter in every state except Queensland. Appendix 11 shows the total wind output by state and month for each year from 2004-2011.


Continuous hours below 20%: 2005
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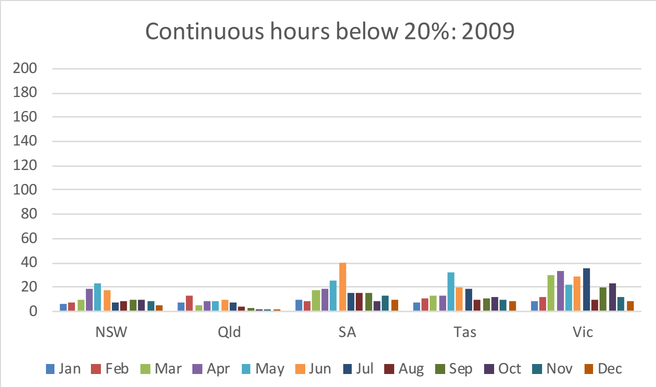
Continuous hours below 20%: 2009
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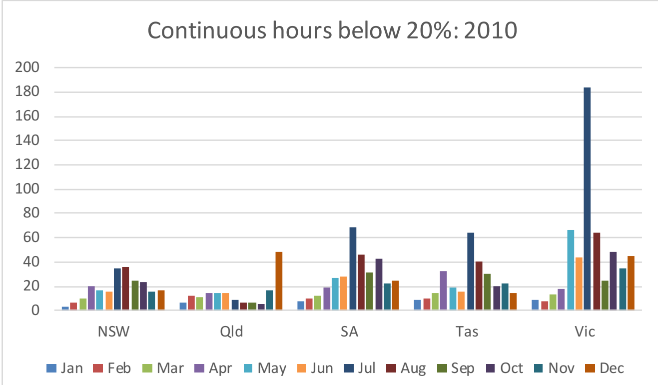
Continuous hours below 20%: 2010
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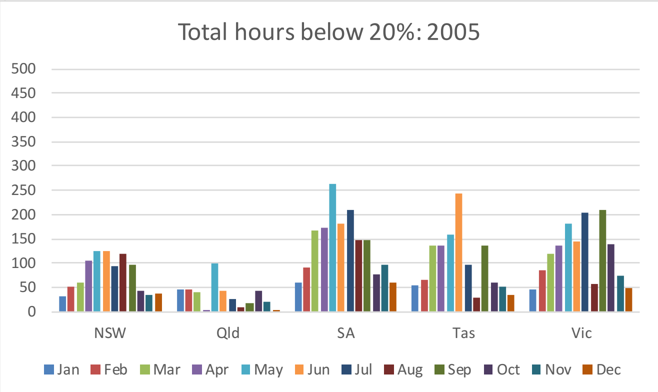
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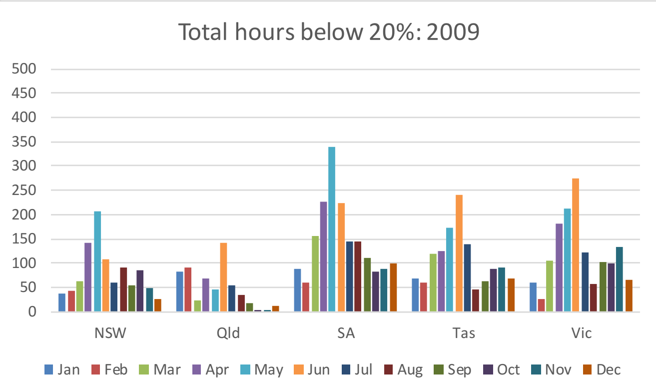
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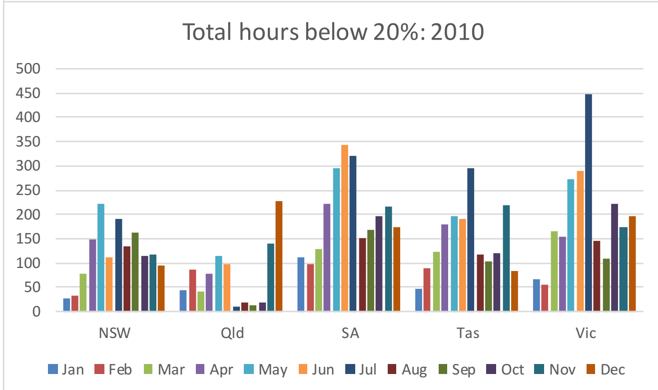
Total hours below 20%: 2010
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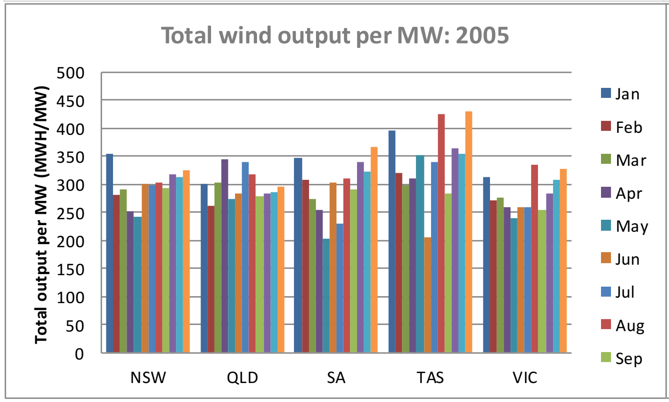
Total wind output per MW: 2005
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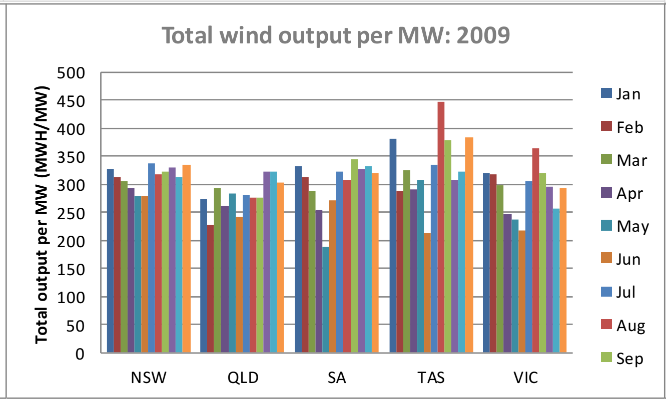
Total wind output per MW: 2009
Total output per MW (MWH/MW)
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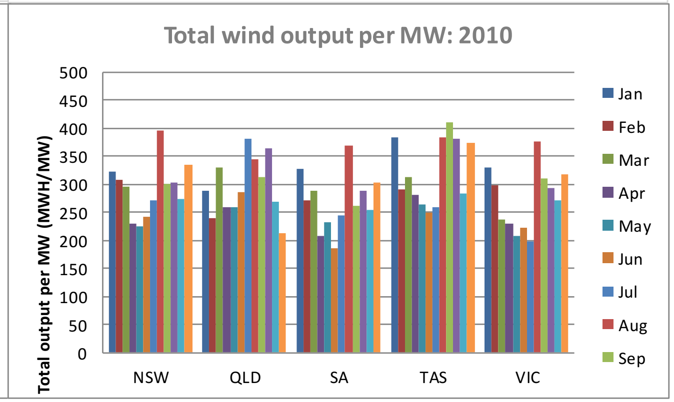
Total wind output per MW: 2010
Total output per MW (MWH/MW)
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From the limited data set reviewed, there does not appear to be a correlation between low wind output and heat waves, and indeed the low wind periods appear to fall consistently in winter. However, it is recommended that the study is extended to include running multiple years, in order to identify maximum storage requirements, and to include analysis of a much longer period of weather data.

5.4.4 Onshore Wind and Utility Solar – SWIS

The AEMO 100% RE study (Australian Energy Market Operator (AEMO) 2013) was restricted to the NEM, so data were not available to do the same analysis for the SWIS region within Western Australia. It was not possible to consider a wide range of locations in Western Australia, or to identify the worst year from an extensive dataset. It is hoped that these data will become available in the near future, so that future studies of this kind can use consistent data across Australia.

Fortunately, and unlike the NEM, the AEMO website for the SWIS provides the output at half-hourly intervals for every market generator. Historical half-hourly data for 2010 were downloaded for all wind generators connected to the SWIS network. The generator outputs were averaged to estimate a single hourly profile for the region. This embodies an assumption that future wind generators will be built at similar locations to the present ones.

There were no operational utility-scale solar PV plants in the SWIS in 2010. Instead, output data for generators existing in 2016 was used.

Due to limitations on available data, the calculation of energy storage requirement for the SWIS is in some respects inconsistent with that for the NEM. This shortcoming can be addressed in a subsequent, more comprehensive study; meanwhile, the impact on the Australia-wide storage requirement is relatively small.

5.4.5 Rooftop Solar – NEM and SWIS

Rooftop solar PV generation makes a substantial contribution to Australia’s electricity supply, though with different characteristics to utility-scale solar, so it was modelled separately. Rooftop solar is non-tracking but a wide variety of pointing angles tends to broaden the overall daily output profile. This same variety, lack of maintenance, and various shading environments reduce the capacity factor of the aggregate generation resource.

Measured hourly irradiance and output data are provided by SMA for PV systems funded by the National Solar Schools Program, and were accessed through the Australian PV Institute’s PV Maps tool (Australian Photovoltaic Institute n.d.). Complete annual data are not available for most states, in particular for the study year of 2010. Instead, the SMA data were used to calculate the relationship between solar irradiance and PV output for rooftop PV systems in aggregate. This was multiplied by typical-year irradiance data for each state.

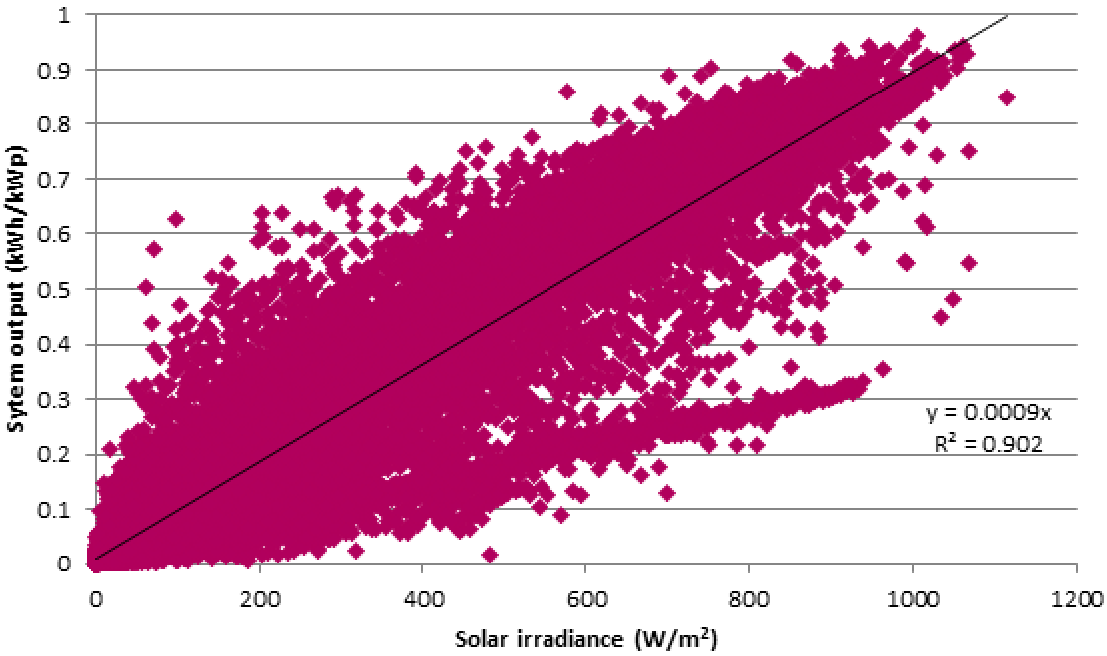
The relationship between irradiance and output was obtained by downloading a year’s worth of output data for the ten available sites in NSW, which were all situated within the Greater Sydney region. NSW was chosen as it had the greatest number of data points; to a reasonable approximation, the variation in pointing, condition, and shading of rooftop PV systems will be similar in all states, so using NSW data should not unreasonably bias the results. Hourly output in kWh was normalised by dividing by the system size in kWp. These values are shown as a scatter plot against irradiance in watts per square metre in Figure 22. A line of best fit had a coefficient of determination of 0.902, suggesting a strong linear relationship, while the thickness of the scatter plot about this line shows the variety of system performance that is encountered in practice.

Rooftop PV output data would ideally be obtained for the same year as utility-scale wind and solar generation data, to allow for any potential correlation between wind and solar resources, as discussed above. However, 2010 data for rooftop solar PV are not consistently available around Australia, so rather than using incomplete data sets, an output trace for rooftop solar was obtained for a typical year. Irradiance data for a typical year for each state was generated using the Meteonorm software from the

Swiss company Meteotest (Meteotest Switzerland 2015). By multiplying the hourly irradiance by the slope of the line of best fit, average rooftop solar PV outputs were generated for each state.

Figure 22 Linear regression of rooftop solar PV output versus solar irradiance

5.4.6 Overall capacity factors



The overall capacity factors by technology type and state are shown below in Table 15. The capacity factors used in this study originate from the ROAM data for wind and utility solar, and are high compared to some other sources (Bureau of Resources and Energy Economics 2013; Teske et al. 2016). However, the ROAM data were not modified, as they are from a well cited and well understood source, and the impact would appear as a change in the energy scenario rather than an important change in the energy storage requirement.

Table 15 Modelled capacity factors by technology and state

	NSW	QLD	SA	TAS	VIC	SWIS	BREE [1]
Wind 2	40%	40%	37%	44%	38%	37%	38%
CSP (no storage) [2]	32%	32%	34%	29%	30%	25%	23-31% [3]
Utility PV [2]	32%	32%	34%	29%	30%	25%	24%
Rooftop PV [4]	16%	19%	19%	14%	15%	21%	

Note 1 Bureau of Resources and Energy Economics, 2013

Note 2 Wind and solar capacity factors by state are directly from the AEMO modelling (Australian Energy Market Operator (AEMO) 2013) *except for the SWIS, which is based on historical output from operating wind farms. No capacity factor is given for the ISF modelling, as CSP was only modelled with xx hours storage, with a 57% capacity factor.*

Note 3 Variation is technology dependent, with 23% for trough and linear Fresnel systems, and 31% for tower systems.

Note 4 Derived from Australian Photovoltaic Institute (n.d.) *data*

6 RESULTS – STORAGE REQUIREMENT

6.1 Key findings

The study identifies the energy storage requirement for power system reliability, or "keeping the lights on", which has two components called in engineering terminology *adequacy* and *security*. System adequacy is the ability to supply enough energy at the right times to meet customer demand. System security is the ability of the system to withstand sudden changes or contingency events, such as the failure of a large generator or transmission line. Providing adequacy and security is a core requirement of the electricity market, and systems are in place to ensure they are maintained – notably the Project Assessment of System Adequacy (PASA) over multiple forecasting periods, and the Frequency Control Ancillary Services (FCAS) markets which also have multiple, much shorter, time frames.

Table 16 shows the energy storage requirements indicated by this study, highlighting in bold type that for system adequacy the quantity of energy (GWh) is most important, while system security requires near-instantaneous delivery of power (GW) to compensate for sudden shocks to system operation.

Table 16 Summary of storage requirements: BAU RE, PARIS RE, & HIGH RE scenarios

		BAU RE 2030	PARIS RE 2030	HIGH RE 2030
Renewable % of generation		36%	52%	75%
Storage requirement for energy adequacy	GWh	1.5	5	105
	GW	0.4	1.5	9.7
Storage requirement for system security	GWh	0.5	1.4	2.9
	GW	5.8	16.8	35.2
Total demand	GWh	239,134	239,134	239,134
Total capacity	GW	79	85	101

Note 1: Although described here as a requirement for storage, system security requires a fast frequency response, that can be provided by storage or by some other means.

The adequacy requirement is due to a mismatch between the times of variable renewable generation and variable demand, as overall there is sufficient energy generation on a monthly basis. While demand response and demand management could contribute to meeting the adequacy requirement, it is likely that the majority of any shortfall in supply will need to be met by stored energy within the given generation mix.[14] Multiple storage technologies could meet this requirement, with different costs and characteristics.

The requirement has been defined by examination of an unfavourable year for wind generation, with extended periods of low output. The limitations of the study meant that a relatively short period of weather data was interrogated (seven years).

The security requirement can also be met by several means. The traditional approach is to maintain at all times a sufficient level of generation by turbines rotating in synchrony with the grid frequency. Through the inertia of their spinning masses they resist rapid changes in frequency that are caused by contingency events. This synchronous generation can be provided by fossil-fuel and some renewable technologies (hydro, biomass, geothermal, or CSP). Wind turbines can also apply the inertia from their spinning blades

[14] Demand response can be expected to shift load by some hours, but a shortfall of some days is unlikely to be avoided by demand response unless load is curtailed altogether.

to frequency support, called “synthetic” inertia because it is mediated by power electronics, although this is not yet used in Australia.

Batteries have the potential to make an important contribution to replacing inertia with Fast Frequency Response (FFR) that performs the same function. They are cost effective in this role because the energy requirement is very small – Table 16 shows the power requirement for system security, assuming it is entirely provided by energy storage. The corresponding energy capacity requirement allows that FFR should be provided for a period of only five minutes, by which time regular “recovery” FCAS resources are online.

Table 16 shows that the requirements for system security exceed the requirements for adequacy until very high renewable penetrations. In the HIGH RE scenario, system security energy requirements fall far short of the energy adequacy requirements. However, the scale of the fast response capacity needs at this level of renewable penetration may mean a relatively small additional expense would enable this to provide a significant contribution to meeting the adequacy requirement. Assuming the security requirement is met by batteries, scaling those to provide an hour of storage (a common configuration in today’s battery market) could reduce the need for energy adequacy by one third.

The findings of this study concur with the analysis by the German Fraunhofer Institute (Pape et al. 2014), which similarly concluded that the requirements for fast response dominate until very high penetrations of renewable energy generation, and that energy adequacy storage is relatively low even at penetrations of 50% renewable energy.

6.2 Modelled results – system adequacy

The modelling described in Section 4.4 aimed to determine the amount of storage required to ensure system adequacy, that is, to ensure that there is enough energy to meet demand at all times. The model does not determine the storage required to provide system stability, via inertia or equivalents, but addresses the important question of whether a high penetration of variable renewable sources could leave Australian electricity consumers without sufficient energy in times of low supply from variable sources. To this end the supply–demand balance was modelled for a year in which there were protracted periods of low wind energy output, as these conditions were likely to result in the longest sustained period of low renewable output (see Section 5.4). Storage designed to meet that energy gap should be sufficient to cope with other periods of low output. Once installed, that storage should ideally be designed to provide other services to address system security and curtailment.

The overview of results is shown in Table 16, Figure 23, and Figure 25, with the state-by-state results given in Section 0 below. In the HIGH RE scenario, there is 868 GWh of unmet demand after the direct contribution of generation and interconnectors. This results in a storage requirement of 105 GWh, while the maximum capacity shortfall of 9.7 GW (5.6 GW in any one state).

It is important to remember that unmet demand would not occur in a single contiguous time period, so the same energy storage resource can be reused multiple times to meet the total unmet demand. That is, unmet demand is a throughput requirement, and the ratio of storage requirement to demand shortfall outlined above would require less than 8 full discharge cycles from the storage. It is also important to emphasise that this analysis is for a poor year for wind energy. As discussed in Section 5.4, the year 2010 was selected because it was the year with the longest low output periods in the seven year dataset. The storage requirement was also modelled without the inclusion of any storage associated with the concentrating solar thermal in the energy mix.[15] The model assumes a round trip efficiency of electricity from storage of 76%, equivalent to estimates for modern pumped hydro systems; batteries have greater efficiency, hydrogen less.

[15] While it is highly unlikely that CSP would be installed without storage, the modelling has been undertaken assuming zero storage, in order to ascertain the raw storage requirement.

Table 17 Storage for energy adequacy – summary for all scenarios

		BAU RE	PARIS RE	HIGH RE
Total demand	GWh/yr	239,134	239,134	239,134
UNMET DEMAND BEFORE STORAGE				
After generation	GWh/yr	17	59	2,801
After interconnectors - energy	GWh/yr	1.8	12.2	868
After interconnectors - capacity	GW	0.4	1.5	9.7
STORAGE DEMAND AND EXCESS RENEWABLES				
Storage requirement for energy adequacy	**GWh**	**1.5**	**5**	**105**
Potential curtailment (pre-storage)	GWh/yr	1,292	3,413	33,842
Potential curtailment (pre-storage)	%	1%	3%	16%
GENERATION				
Renewable	GWh	86,787	125,326	180,225
Coal, gas & diesel	GWh	152,345	113,795	58,040
Via interconnectors(1)	GWh	15	46	1,766
Total		**239,132**	**239,121**	**240,031**
Renewable %		36%	52%	76%

Note 1: The total net amount that is imported into all states.

Electricity generation must balance load at all times, so in the absence of storage, variable generators are frequently turned off ("curtailed") if there is more supply than demand[16]. The figure noted for "potential curtailment", equivalent to 17% of production from wind and solar generation, is high. However, this is *prior* to storage. Actual curtailment would be considerably less, for the following reasons:

The unmet demand (pre-storage) is what defines the storage requirement, and sufficient storage would be installed to supply this demand. The storage will primarily be charged by excess renewables, as the marginal operational cost is zero or close to zero, especially when the alternative is curtailment. The market will therefore favour RE over fossil fuel-powered generation.

Once storage is installed, it is likely to be operated to maximise charge/ discharge cycles as long as this is economically beneficial. Operators are likely to store energy when energy prices are low, which will correspond to times when renewable production exceeds demand.

Renewable operators may themselves install storage specifically to reduce lost revenue as a result of curtailment, particularly as storage costs come down, and would certainly use that storage to reduce their own curtailment. Any installations of this type would have the effect of improving energy adequacy.

Thus the effect of storage would be to reduce the curtailment of renewables, and displace some of the remaining fossil generation. In the HIGH RE scenario, if curtailment of renewables was avoided altogether, it is likely that renewable generation would supply closer to 90% of electricity.

[16] For example, rooftop solar systems (without storage) are often automatically turned off as a reaction to voltage rises, which occur when the generation is in excess of the load.

In the BAU RE scenario, the storage requirement for energy adequacy is 1.5 GWh, and the unmet demand is only 1.8 GWh per year, occurring over only 8 hours. The capacity shortfall is 0.4 GW, and potential renewable curtailment is 1%. It should be noted that the supply mix modelled is considerably different from today's, with almost one third more capacity for very similar total demand.

In the PARIS RE scenario, the storage requirement for energy adequacy is 5 GWh, and the unmet demand 12.2 GWh per year before storage, occurring over 47 hours. The capacity shortfall is 1.5 GW, and potential renewable curtailment is 3%.

In both the BAU RE and PARIS RE scenarios there is a renewable penetration considerably higher than today, combined with a requirement for energy adequacy storage far lower than the requirements for system security. This is in line with findings from a forward looking study of the German system (Pape et al. 2014).

The German Fraunhofer Institute undertook a detailed analysis on behalf of the Federal Ministry for Economic Affairs and Energy about Germany's future storage demand (Pape et al. 2014). This research project "Roadmap Speicher" analyses the demand for additional storage as a result of the projected increase in renewable energy. The analysis differentiates between a mid-term perspective, in which the renewable share of power generation is between 45% and 69% in Germany (26%–37% in Europe), and a long-term perspective where the renewable energy share is 88% in Germany (82% in Europe). The analysis concluded that flexible fast response for energy security is going to be the main priority, and that this can be achieved using a range of fast response technologies, including demand response. Reaching the mid-term goals of the "Energiewende" (60% renewable power generation) will not require the installation of new storage capacities for adequacy purposes, although these are expected to be required to reach the longer term goal of 80% (Pape et al. 2014).

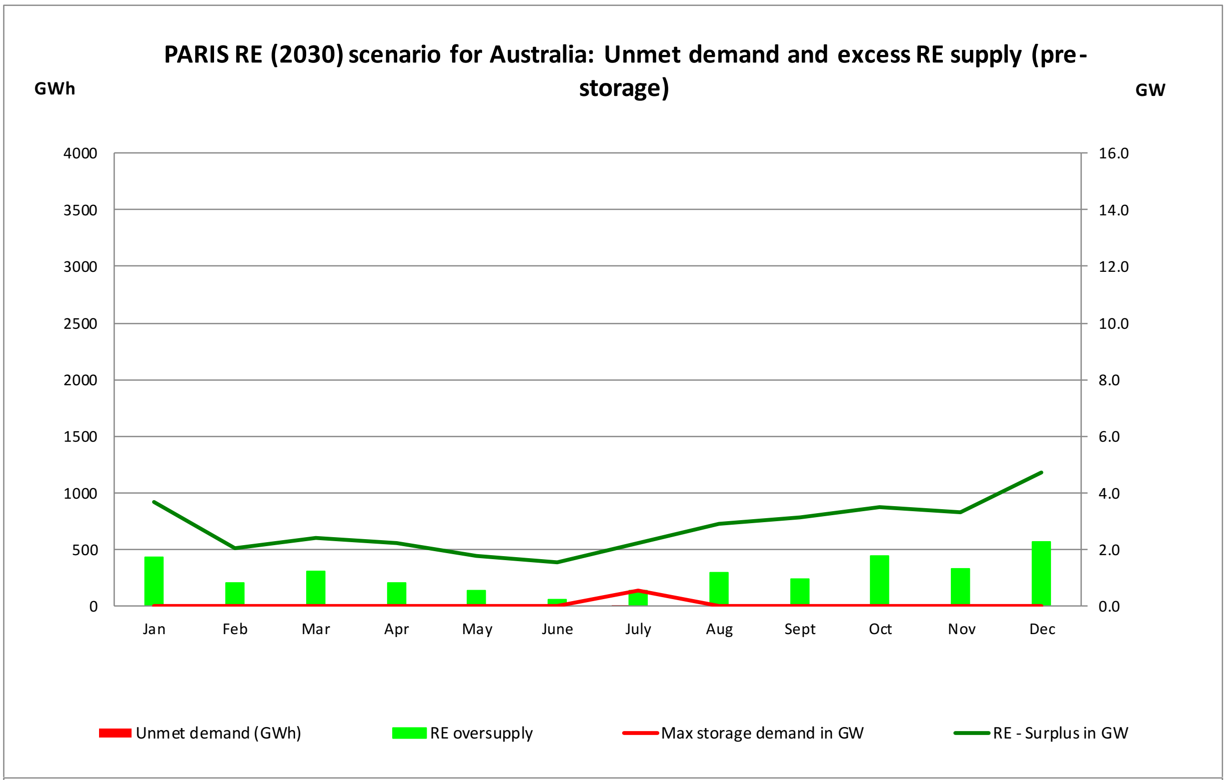
Pape et al. 2014's results are consistent with the outcomes from this study, which also concludes that the requirements for fast response dominate the system requirements until very high penetrations of renewable energy generation, and that energy adequacy storage is relatively low even at penetrations of 50% renewable energy.

Australia is fortunate compared to Northern European countries, in that the seasonal mismatch between supply and demand is very slight. This means that energy storage for adequacy may be required for a matter of days or weeks, rather than a matter of months. Indeed, with the supply mix modelled, there is a net oversupply in the system.

Figure 23 shows the overall supply–demand balance through the modelled year. The bars indicate the energy over- and under-supply, that is, the sum of GWh where demand is not met by the existing capacity in real time, and the sum of GWh where the variable renewable supply exceeds demand. There is a net over-supply in all months.

The lines show the maximum capacity shortfall (red line), and maximum overcapacity (green line). In the HIGH RE there is a potential capacity shortfall of just under 6 GW, and 1 GW in the Paris RE. This compares to total supplies of 102 GW and 85 GW in the HIGH RE and Pairs RE scenarios respectively.

Figure 23 Total supply–demand balance, PARIS RE and HIGH RE scenarios



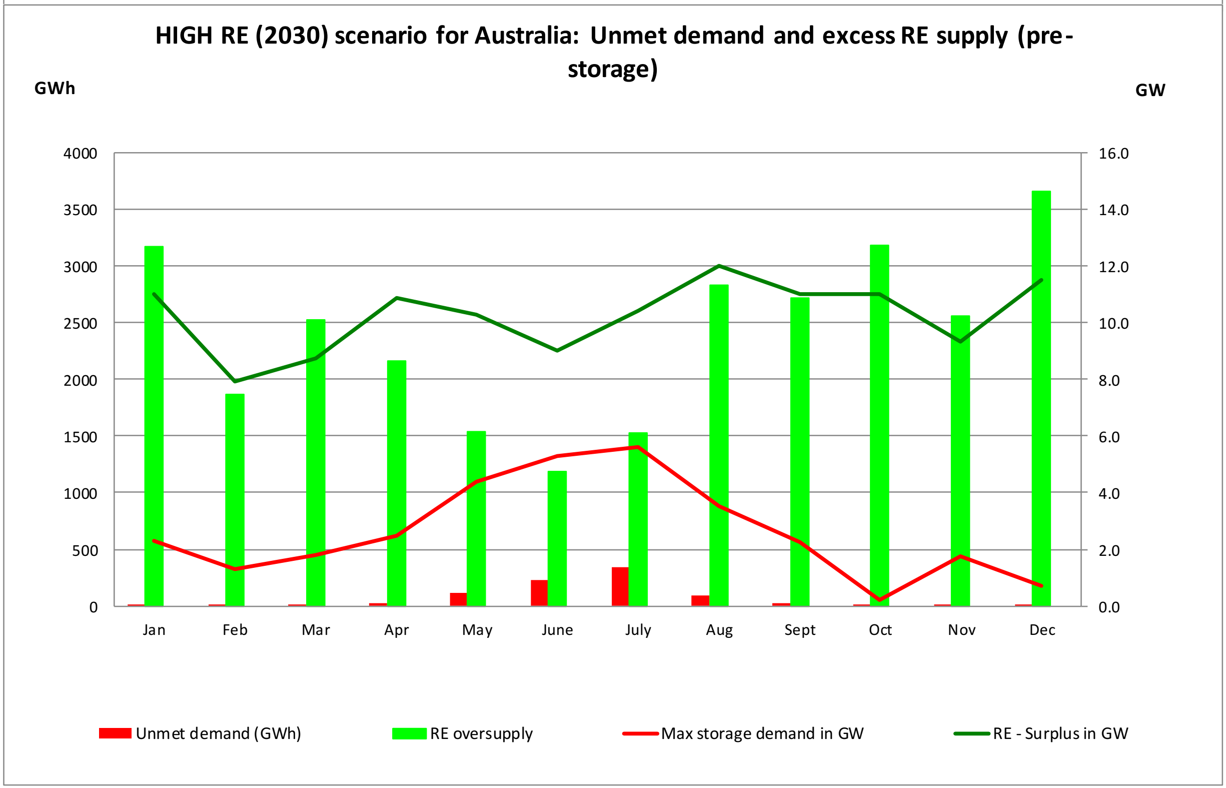


Table 18 PARIS RE scenario results by state (2030)

PARIS RE (2030)		TOTAL	NSW	QLD	SA	TAS	VIC	SWIS
Demand	GWh/yr	239,134	76,804	62,385	14,441	11,100	51,036	23,368
UNMET DEMAND BEFORE STORAGE								
After generation	GWh/yr	59	37	-	-	-	12.0	10.8
After interconnectors	GWh/yr	12.2	1.4	-	-	-	-	10.8
Hours with deficit	hours/yr	47	5	-	-	-	-	42.0
STORAGE DEMAND AND EXCESS RENEWABLES								
Additional storage demand	GWh	5	1	-	-	-	-	1.5
	GW	1.5	0.5	-	-	-	-	1.0
Potential curtailment	GWh/yr	3,413	49	-	2,566	-	735	63
	%	3%	0%	0%	20%	0%	2%	1%
GENERATION								
Renewable	GWh	125,326	41,158	21,712	10,309	11,112	31,309	9,726
Coal, gas & diesel	GWh	113,795	35,610	40,707	4,132	0	19,715	13,631
Via interconnectors(1)	GWh	0	35.1	-34.2	-	-12.0	11.0	-
Total		239,121	76,803	62,385	14,441	11,100	51,036	23,357
Renewable %		52%	54%	35%	71%	100%	61%	42%
Consumer storage	GWh	5.6	1.2	1.0	0.7	0.1	1.4	1.2

Table 19 HIGH RE scenario results by state (2030)

HIGH RE (2030)		TOTAL	NSW	QLD	SA	TAS	VIC	SWIS
Demand	GWh/yr	239,134	76,804	62,385	14,441	11,100	51,036	23,368
UNMET DEMAND BEFORE STORAGE								
After generation	GWh/yr	2,801	1,714	15	-	-	1,067	4
After interconnectors	GWh/yr	868	687	9	-	-	168	4
Hours with deficit	hours/yr	767	471	28	-	-	249	19
STORAGE DEMAND AND EXCESS RENEWABLES								
Additional storage demand	**GWh**	**105**	**86**	**3.4**	**-**	**-**	**13.4**	**2.1**
	GW	**9.8**	**5.6**	**1.4**	**-**	**-**	**2.0**	**0.8**
Potential curtailment	GWh/yr	33,842	12,901	6,650	3,656	1	5,740	4,894
	%	16%	16%	15%	26%	0%	12%	27%
GENERATION								
Renewable	GWh	180,225	65,520	37,720	10,407	11,614	41,405	13,559
Coal, gas & diesel	GWh	58,040	9,592	25,539	4,403	0	8,701	9,805
Via interconnectors[(1)]	GWh	0	1,005	-883	-368	-514	761	-
Total		**238,265**	**76,117**	**62,376**	**14,441**	**11,100**	**50,868**	**23,364**
Renewable %		76%	86%	60%	72%	105%	81%	58%
Consumer storage	GWh	5.6	1.2	1.0	0.7	0.1	1.4	1.2

Note 1: The net amount imported or exported into the state.

6.2.1 Detailed results – system adequacy by state

System adequacy storage requirements are shown for the PARIS RE and the HIGH RE scenarios in

Table 18 and

Table 19. The BAU RE scenario results are shown in Appendix 9, and the monthly analysis for both scenarios is shown in Appendix 10. The period with the greatest potential shortfall occurs in July and August in all states except Queensland.

6.2.2 Sensitivity to interconnectors

The option of increasing the interconnector capacities rather than installing storage was tested by running the model with interconnector capacities doubled. The storage requirement went down by 15 GWh (14%) in the HIGH RE scenario. Storage demand was not significantly reduced in the Paris RE scenario as most of the storage requirement was located in the SWIS, which has no interconnectors. The results are shown in Table 20, with the effects of individual interconnectors shown in Table 21. The greatest effect was from increasing the capacity of either the NSW-QLD or the TAS-VIC interconnectors, which resulted in reductions in storage requirements of approximately 15 GWh and 5 GWh respectively.
It should be noted that increasing the interconnector capacities will address requirements for system adequacy, but will do little to reduce variable renewable curtailment.

Table 20 Energy adequacy storage requirement with expanded interconnectors ###

		PARIS RE (2030)		HIGH RE (2030)	
		Current interconnector	X 2 interconnec tor	Current interconnector	X 2 interconnec tor
UNMET DEMAND BEFORE STORAGE					
After generation	GWh/ yr	59	59	2801	2801
After interconnectors	GWh/ yr	12	11	868	651
Additional storage demand	GWh	5	4	105	86.8
	GW	1.5	1	9.7	9.7

Table 21 Storage requirement for NSW and Vic: effect by interconnector HIGH RE

		Current interconnectors	x 2 QLD-NSW	X 2 VIC-NSW		X2 both
NSW	GWh	86	71	86		71
		Current interconnectors	x 2 TAS - VIC	X 2 NSW-VIC	X 2 SA-VIC	X2 all three
VIC	GWh	13	8	13	10	8

6.3 Storage requirement – system security

A simple estimate of the energy storage capacity per state to compensate for loss of inertia is based on total capacities of generation technologies.

Table 22 shows that the asynchronous generation capacity (lacking inertia) in most states is presently in the range 10–20% of the total generation capacity per state. SA is notably different at 53%, so it is clear from this simple measure that system security is potentially much more challenging in SA. Challenges may occur when renewable generation is dominating energy supply, if the wind generation component is not enabled to provide synthetic inertia.

The literature discussed in Section 4.2 did not provide a straightforward calculation of the FFR requirement for a given penetration of asynchronous generation. Even the calculation of system inertia at a particular time does not depend in a straightforward way on the real-time generation mix, and requires the loading on each generation unit to be modelled. A detailed calculation of system dynamics is beyond the scope of the present study. Therefore, considering that lack of inertia has posed a growing system security risk for some years in SA, this report has made the simplifying assumption that any asynchronous generation capacity beyond 30% of the state total should be matched by an equivalent capacity of FFR resources.

Accordingly,

Table 22 shows the requirement for FFR in each state, at present and in the three 2030 energy mix scenarios, and the final two columns show the necessary capacity of batteries should they be selected to meet the FFR requirement. System security drives the power (GW) requirement; the energy storage (GWh) requirement is based on supplying an FFR response for 5 minutes until the delayed FCAS response is contracted to commence restoring the grid frequency. This is a conservative assumption because a proper statistical analysis of supply at risk through a variety of contingency events, including coincident events, would be likely to find that a smaller amount of FFR is required. However, the finding that requirements for fast response dominate until very high penetrations of renewable energy generation is consistent with the findings of Pape et al. (2014), reported in Section 6.1.

The FFR requirement can be met in a number of ways, including the inertia of fossil-fuel generation and some forms of renewable generation. Using “synthetic" inertia from wind turbines is another way to meet this requirement. This form of inertia can be provided with present technologies. These forms of FFR are only available when the particular generators are operating, and this may not be the case at times when the renewable fraction is high, as it depends on the available energy mix of each region. Batteries have the advantage that they don’t have to be charging or discharging to offer this service: they only need their power electronic systems energised to be ready for immediate operation.

Batteries are cost-effective if installed with a high power-to-energy ratio. Installing GW capacity for the purpose of FFR, however, creates the opportunity to expand their GWh capacity at a lower marginal cost than would be the case without the FFR purpose. Having invested in FFR batteries, the incremental cost of adding more GWh capacity depends on the relative cost of the battery cells and the BOP, but is likely to be cheaper than other options, including pumped hydro, even when that would otherwise be the cheapest standalone solution. The FFR and adequacy requirements interact to some extent, because when the storage is charging or discharging to shift energy according to resource availability, its GW capacity is decreased in one direction and increased in the other, affecting its FFR capability at that time. This interaction would be appropriate as the subject of a further study.

What would this have meant for the South Australian Blackout on 28th Sept 2016?

It's reasonable to ask whether FFR resources such as grid-scale batteries would have prevented the blackout that followed storm damage to the SA transmission system in September 2016. The resulting voltage disturbance caused 315 MW of wind generation to disconnect, and the flow on the Heywood interconnector from Victoria increased to between 850 and 900 MW to make up the difference. This flow exceeded the design limit of 600 MW, and the interconnector's protection system opened the circuit to prevent damage, resulting in rapid frequency collapse.

Wind generation could have been part of a solution. Had the correct fault settings been in place to ride through the voltage disturbance, the more recently installed wind turbines could themselves have provided synthetic inertia with suitable control settings.

Other forms of FFR would have bought time for other generation resources to come online. With 600 MW of fast responding batteries, corresponding to the interconnector as the largest single component of SA supply, the loss of generation would have been almost instantly compensated. Conversely, the loss of the interconnector at any normal flow could also be compensated. At today's prices, $803 million would afford up to 2 hours of supply from these batteries, ample time to respond to the contingency by ramping up reserve generation. It is likely that the blackout would have been prevented or much less widespread.

Table 22 FFR requirements for system security and scale of battery storage to provide it

	SYNCHRONOUS	ASYNCHRONOUS		FFR REQUIRED	BATTERIES	
	MW	MW	%	MW	GWh	GW

Present 2017						
NSW	15,392	2,094	12%	0	0.0	0.0
QLD	12,542	1,803	13%	0	0.0	0.0
SA	2,767	3,075	53%	1,323	0.1	1.3
TAS	2,464	403	14%	0	0.0	0.0
VIC	11,027	2,219	17%	0	0.0	0.0
SWIS	4,968	654	12%	0	0.0	0.0
					0.1	1.3
BAU RE 2030						
NSW	13,487	7,792	37%	1,408	0.1	1.4
QLD	13,908	6,359	31%	279	0.0	0.3
SA	3,047	4,239	58%	2,053	0.2	2.1
TAS	2,464	829	25%	0	0.0	0.0
VIC	10,011	7,079	41%	1,952	0.2	2.0
SWIS	4,628	2,155	32%	120	0.0	0.1
					0.5	5.8
PARIS RE 2030						
NSW	12,167	12,727	51%	5,259	0.4	5.3
QLD	10,828	7,796	42%	2,209	0.2	2.2
SA	3,047	4,941	62%	2,545	0.2	2.5
TAS	2,464	1,158	32%	71	0.0	0.1
VIC	8,561	10,692	56%	4,916	0.4	4.9
SWIS	3,754	4,205	53%	1,817	0.2	1.8
					1.4	16.8
HIGH RE 2030						
NSW	9,497	22,329	70%	12,781	1.1	12.8
QLD	10,168	14,708	59%	7,245	0.6	7.2
SA	3,047	5,663	65%	3,050	0.3	3.0
TAS	2,464	1,376	36%	224	0.0	0.2

VIC	6,581	15,029	70%	8,546	0.7	8.5
SWIS	4,854	6,821	58%	3,319	0.3	3.3
					2.9	35.2

6.4 Potential growth in un-modelled storage

Customer energy storage has a multi-faceted value proposition and will grow substantially without any policy support. Rooftop PV generation, both residential and commercial, is anticipated to grow a NEM-wide capacity (excluding the SWIS) of 16 GW by 2030. Battery energy storage integrated with it is anticipated to grow to 2.7 GW, comprising about 4.8 GWh of energy capacity (Australian Energy Market Operator (AEMO) 2016b). The present buoyant residential battery storage market suggests that this may underestimate the penetration of batteries. Nevertheless, it is a substantial capacity and is included in the modelling in Section 6.2.

Grid-side energy storage to help manage distribution networks also has the potential to grow substantially, as several network utilities develop test projects to become familiar with the potential applications. MW-scale battery systems are already being used by utility companies to manage power flows. While the economic case for using batteries is not necessarily convincing for the demonstrations, they have proceeded because they anticipate that energy storage will soon be a more efficient investment than a traditional “poles-and-wires” solution.

Some network companies and commercial enterprises, such as mine sites, operate remote power supplies that can present an attractive business case for energy storage. This is particularly the case for responsive storage to manage variable power flows in a hybrid power system. However, while this storage is critical for the reliability of these systems, it will have no impact on the reliability of the interconnected power system, and is beyond the scope of this study.

Projections for uptake of energy storage tend to focus on customer storage and grid-side storage is harder to estimate (AECOM 2015; Brinsmead, T.S.; Graham, P.; Hayward, J., Ratnam, E.L., Reedman 2016). This may be because network applications are highly locational and a detailed survey of network constraints may be needed to quantify the potential storage requirement.

6.4.1 Application to reliability

MW-scale grid-side batteries are likely to create a significant quantity of energy storage that could be used for multiple purposes, given suitable regulatory incentives, which may include a role for networks in delivering market services which they presently cannot do. As discussed in Section 6.2.2, these would be ideal resources to meet a system security requirement.

With an appropriate control method, and if they are aggregated to form a large capacity of storage that may be dispatched as a unit, residential batteries can also participate in providing energy services that may include adequacy and security support. The existing electricity market rules permit aggregated market participation of electricity generation or storage from behind customer meters, through a market aggregator or a retailer, and at least one Australian company has developed the means to do this. It is interesting to consider whether related mechanisms will be practicable for reliability services.

To contribute to the storage requirement for system adequacy discussed in Section 6.2, a very large quantity of customer energy storage units would need to be held at full charge for a period ahead of a predicted shortage of supply. They could then be progressively discharged as needed. Although customer energy storage units are well suited to responding to frequent, short-term demand response events, it is hard to imagine a business case being developed to contract customers to offer their batteries in this way for what might be a very rare event, perhaps not occurring in a decade, though lasting several days when it does happen. The use of customers’ batteries in this way might become viable when renewable energy penetration is very high and such events are frequent enough for customers to be interested in participating.

To contribute to the storage requirement for system security in Section 6.2.2, a response time of 1-2 seconds or less will be required. It is challenging to dispatch residential batteries within the existing fast FCAS timeframe of 6 seconds. A significant part of this time is needed even to measure the frequency with enough accuracy to decide whether a response is needed – the voltage and current waveforms on the distribution networks to which residential customers are connected often exhibit significant distortion from an ideal sinusoid. Then, after detecting a rapid change in frequency, multiple levels of control should be navigated within the battery controller and inverter, which may not have been designed for especially fast response. This application is better suited to specialised storage controls that might be afforded for MW-scale systems connected to higher-voltage networks.

6.5 Northern Australia

In northern WA, NT, and remote parts of Queensland, energy storage will be used to integrate solar or other renewable energy sources at diesel and gas power stations to improve the operating regimes of the fossil-fuel generators, and there are already several precedent projects that highlight this opportunity for energy storage. Notable present projects in northern Australia include a MW-scale battery installation at the De Grussa mine (ARENA 2016) and pumped hydro being developed in an abandoned mine at Kidston (ARENA 2017b), both of which are supported by ARENA. There are older projects developed by Horizon Power that used flywheel storage to help manage hybrid power supplies – although the role of flywheels as responsive storage has largely been overtaken by lithium ion batteries. There is potential for tidal power and tidal storage on the north coast of Australia where the tidal range is large.

The prospect of renewable energy export by ship or cable includes big opportunities for energy storage, particularly in batteries, as hydrogen (stored in compressed or liquefied form or as ammonia), and pumped hydro. However, this market is unlikely to be mature in 2030. Hydrogen produced by electrolysis of solar energy can be exported by ship to multiple international markets as compressed gas, liquefied hydrogen or as ammonia. This enterprise is being developed at demonstration scale (Want and Cooper 2014) and may have a role in stimulating hydrogen transport and storage for a local market. Direct export of electricity via submarine HVDC cable is technically feasible, and the commercial case has potential subject to a number of uncertainties that remain to be quantified (Mella, James and Chalmers 2017). The energy storage requirement to maximise the capacity factor of the cable is around 7.5 GWh to support the likely 3 GW scale of the first cable laid. Interestingly, initial analysis of LCOE indicates that this quantity of battery energy storage could be installed with little impact on the LCOE and could even reduce it, due to the economic impact of more efficient use of the cable.

6.6 Discussion

Modelling the storage requirement for energy adequacy and examination of the requirements for system security result in an identified need at 2030 for 5 GWh / 1.5 GW in the PARIS RE and 105 GWh / 9.7 GW in the HIGH RE scenario for energy adequacy, and for 17 GW and 35 GW respectively for system security. Requirements in the BAU RE scenario were only 1.5 GWh for system adequacy, and 5.8 GW for system security, with the requirement for system security greater than that for energy adequacy. There are many alternatives for meeting these requirements, and the actual mix of storage or other technologies used will depend on a mixture of market dynamics, policy settings and consumer preferences.

Some storage will be installed entirely independent of the system requirements, particularly behind-the-meter consumer-driven battery storage. The current AEMO forecast for uptake of small-scale storage systems is 4.3 GWh by 2030 (Jacobs Group 2016), although some studies put this estimate considerably higher (Wilton 2017). This consumer storage could potentially make a significant contribution to the BAU RE requirements for system security. The present regulatory settings only allow this service provision through aggregation as a market load, because there is a 1 MW capacity limit for market bids, and the bidder must be a registered market participant, so individual market participation by customers is not presently available without regulatory change. It remains to be seen whether the market provides sufficient signals for consumers to allow their storage systems to be used in this manner. At least one technical solution has been demonstrated in which customer batteries were enabled for FCAS provision by a distributed control platform and then triggered locally to provide sufficiently fast response (ARENA 2015).

In the BAU RE and PARIS RE scenarios, consumer storage would theoretically be sufficient to provide the entire energy adequacy requirement, although behind the meter storage is unlikely to interact with utility scale renewable energy. However, the adequacy requirement is small, occurring in only 12 – 47 hours in total, and could be managed by measures such as demand response.

The adequacy requirement in the HIGH RE scenario is significant (105 GWh), and it is hard to imagine how this could be met other than by utility scale bulk storage.

6.6.1 Technology options for meeting the requirement

Judging by the LCOS estimates given in Section 2.1, it is likely that the larger scale options such as compressed air or pumped hydro will be the lowest cost for bulk energy storage. There is approximately 128 GWh of pumped hydro potential identified in the NEM, with 98 GWh of that within the lower cost range (see Section 2.3.5). These technologies would also make a significant contribution to reducing potential curtailment, although this could also be achieved by power-to-gas storage.

The very low LCOS of molten salt storage means that CSP plus molten salt is likely to make a contribution to storage requirements, assuming the need for flexible generation to complement increasing shares of variable renewable generation is reflected in the market arrangements. However, the storage associated with the CSP in the modelled generation mix has not been factored into the calculations in this study, as the objective was to determine the "raw" storage requirements.

Indicative costs have been calculated using just two technologies, batteries and pumped hydro, to meet reliability requirements, although it is highly likely that requirements would in fact be met by a mix of technologies. These two technologies have been chosen for simplicity, as it would physically be possible to meet the reliability needs in this manner, but this is not intended to imply that this is an optimum solution.

If one assumed that the entire energy adequacy requirement was to be met by pumped hydro, costs to meet this requirement for the HIGH RE scenario would be in the order of $43 billion (note this does not allow for the contribution from whatever solutions are used for system security).

Should the entire requirement for system security be met by batteries, and with the caveat that prices are based on a two hour battery rather than a half hour battery, costs for the High RE scenario would be $47 billion at current prices and $22 billion at 2030 prices. For comparison, assuming that sufficient industrial load were available, an indicative cost for instantaneous demand response would be $16-40 billion[17].

For context, annual network capital spending in the NEM is between $5-6 billion each year based on the current Regulatory Investment Notices, equating to approximately $71 billion if this figure is extended to 2030.

Whatever solutions are chosen for system security will also mitigate the need for energy adequacy, and vice versa. If it is assumed that two hour batteries are used to meet the security requirement, and the remaining adequacy requirement was met by pumped hydro, the total cost in the High RE scenario would be $36.5 billion for both adequacy and security. It should be noted that there are other means to meet both of these requirements, and the costs provided for these technologies are merely an example of one alternative to meet the requirements.

Meeting the security requirement for the Paris RE scenario would cost in the order of $11 billion at 2030 prices, using batteries for FFR, and would entirely mitigate the requirements for energy adequacy.

6.6.2 Conclusion

This study provides reassurance that Australia can reach penetrations of renewable energy close to 50% without significant requirements for energy adequacy storage, and that system security requirements will dominate until very high renewable energy penetrations are reached. The modelling is not equivalent to a comprehensive system adequacy study, but rather gives indicative results which should be sufficient to guide both policy and further research.

The study also provides reassurance that requirements for both adequacy and security may be met with available technologies. However, the policy and regulatory environment may require modification to ensure that we get the most cost effective system outcome.

It is important for energy storage policy to promote market growth, while also managing risk. This includes taking a long-term view of climate targets, as the lowest cost options for energy adequacy and security may be very different. While significant energy adequacy requirements do not occur until Australia approaches zero emissions, the lowest cost solutions for adequacy may well mitigate security requirements at much lower renewable penetrations. Storage technologies which enable the development of an active renewable energy export industry may also advance the market for domestic power system requirements.

In the short term, it is important to provide a regulatory environment that is suited to the distributed future, as the potentially significant contribution from consumer storage could otherwise be lost. This regulatory environment would seek to improve the market by breaking down barriers to consumers accessing additional value streams from their systems.

It would be highly advantageous to extend this study to carry out a cost optimisation between generation mix, storage, increasing interconnector capacity, and demand side activities, factoring in both the requirement for security and for energy adequacy. This should include a quantitative market impact analysis, as energy storage may become a price setter rather than a price taker for some energy services.

[17] The cost of industrial demand response in the US is between $65/kW and $160/kW on an annual basis (EIA 2016). To compare to battery prices we've calculated a net present value over 10 years using a discount rate of 8%.

It should also include analysis of a longer time series of weather data. Such analysis would best be undertaken for the renewable penetrations that are likely to be needed to comply with the Paris targets, and for an electricity system approaching zero emissions, to ensure that policy makers consider the most efficient long-term outcome.

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Appendix 1 Energy storage technologies

This Appendix is adapted from Section 2 of the Phase 1 report for this project (Banfield and Rayner, 2016).

Pumped Hydro Energy Storage (PHES)

PHES accounts for over 99 per cent of bulk energy storage capacity worldwide (Blakers 2015) and is a well-established technology (TRL 9). Australia has over 1.5GW of PHES connected to the NEM; however no large-scale pumped hydro facilities have been built in Australia in the last 30 years (AECOM 2015). The three existing PHES facilities are the 600MW Tumut-3 and 240MW Shoalhaven facilities in New South Wales, and the 500MW Wivenhoe facility in Queensland (Hearps et al. 2014). In PHES systems, large volumes of water are pumped from a lower to an upper reservoir, thus converting electrical energy into gravitational potential energy. When energy is required, the water is allowed to flow from the upper to the lower reservoir and drive a turbine, which generates electricity.

Compressed Air Energy Storage (CAES)

CAES systems store energy by compressing ambient air and storing it at high pressure in underground geological structures such as caverns, aquifers and abandoned mines. The compression of the air generates a lot of heat, which must be removed before storage. When the energy is required to create electricity, the compressed air is released, heated, and used to drive a turbine. Current systems use natural gas to heat the expanding gas. However adiabatic systems are being developed which will store the heat removed from the pressurised air and use it to reheat the expanding air. Adiabatic CAES systems have the potential to increase the efficiency of CAES and remove the need for combustion of fossil fuels. A pilot plant, planned by a German-led international consortium, is scheduled to start operations in 2018 (Energy Storage Association 2016).

Isothermal CAES is a developing technology in which the pressure-volume curve of the air during compression and expansion is controlled to resemble an isotherm. This process wastes less energy, increases efficiency, and reduces capital costs relative to adiabatic CAES (Energy Storage Association 2016).

Australia currently has no deployments of CAES technology (Cavanagh et al. 2015) and there is a limited range of geological conditions that are suitable for a facility similar to the two large non-adiabatic CAES systems that are presently operating in Germany and the US.

Electrochemical Storage (Batteries)

Battery technologies have existed for decades and are ubiquitous in modern society. They use reversible chemical reactions to convert stored chemical energy into electricity and vice versa. There is a wide variety of battery technologies available with different maturities, strengths, opportunities, weaknesses and challenges. Three types of batteries are considered in this study and they are described in the following paragraphs. They have been chosen as examples that are likely to be suitable for large-scale use in Australia. A range of other technologies were considered in the Phase 1 report for this project (Banfield and Rayner 2016).

6.6.3 Advanced Lead-Acid Battery

Invented over 150 years ago, lead-acid batteries are the oldest type of rechargeable battery (AECOM 2015) and they are therefore a well-established technology (TRL 9). Historically, lead-acid batteries are the most common type of battery used for transport and off-grid power supply applications. In their traditional form, they have been coupled with solar, wind and off-grid systems and are considered a cheap and reliable form of storage.

Innovations in electrode and electrolyte technologies are creating advanced lead-acid batteries that address their main historical shortcomings of limited depth of discharge and poor cycling performance. An Australian technology developed by CSIRO and commercialised by Ecoult (Mckeon, Furukawa, and

Fenstermacher 2014) is one example of an advanced lead-acid battery that can compete with lithium-ion batteries on their cycling performance at intermediate states of charge. Lead-acid batteries retain an important advantage: they have a very high power delivery capacity. This is why they have performed so well as starter batteries for automobiles.

6.6.4 Lithium Ion (Li-ion) Battery

Lithium-Ion (Li-ion) batteries (TRL 9) are the dominant technology for energy storage for small-scale appliances such as phones and laptops, and are increasingly being used for electric vehicles, back-up power supplies and domestic storage (AECOM 2015). Increasing scale and volume of manufacturing by major companies is driving large cost reductions, which are expected to continue. Li-ion technologies are becoming a common replacement for lead-acid batteries and are expected to be the dominant battery technologies for most applications in the near future (AECOM 2015). The technologies are still developing and have considerable potential. Current research is focused on improving lifetime and cycling.

There are many Li-Ion variants with different characteristics and with varying levels of feasibility for widespread use. Some of the different chemistries used are:

- lithium iron phosphate ($LiFePO_4$)
- lithium titanate (LT)
- lithium cobalt Oxide ($LiCoO_2$)
- lithium manganese oxide (LMO)
- lithium nickel cobalt aluminium oxide (NCA)
- lithium nickel manganese cobalt (NMC)
- lithium polymer
- lithium metal polymer (LMP)
- lithium air
- lithium sulphur.

The different types of Li batteries have varying TRLs; some are common such as LiFePO4, LiCoO2, and NCA; some are receiving new attention such as NMC, which is valued for its long cycle life; some, such as Li-air and Li-S are still at the research and development stage.

6.6.5 Flow batteries

Unlike conventional batteries, the energy in flow batteries is stored in one or more electro-active species, which are dissolved in liquid electrolytes. Electrolytes are stored in tanks external to the battery, and pumped through electrochemical cells which convert chemical energy to electricity (Cavanagh et al. 2015). The power capacity of a flow battery is controlled by the size and design of the electrochemical cell, and the energy capacity is dependent on the size of the storage tanks. Flow battery technology has several utility applications, including time shifting, network efficiency, and off-grid use. These batteries are also suitable for connection to renewables and time-shifting at the industrial and residential scale.

There are two mains types of flow batteries:

Vanadium redox battery (VRB)
Vanadium redox batteries store energy using vanadium redox couples, which are dissolved in sulphuric acid electrolyte solutions at all times. The first vanadium redox battery was demonstrated at the University of NSW in the late 1980s, and they have been used commercially for over 8 years (Energy Storage Association 2016) making them an established technology (TRL 8).

Zinc bromine (ZnBr) battery
Zinc bromine batteries consist of two electrode surfaces and two electrolyte flow streams which are separated by a micro-porous film. These batteries were developed in the 1970s by NASA and have recently been commercialised in Australia by Redflow. This technology is mature (TRL 9).

Power-to-gas: hydrogen storage (chemical)

Many pathways for the production and consumption of hydrogen have been identified due to its potential as a fuel with high energy density that converts cleanly to usable energy in the form of electricity or heat.

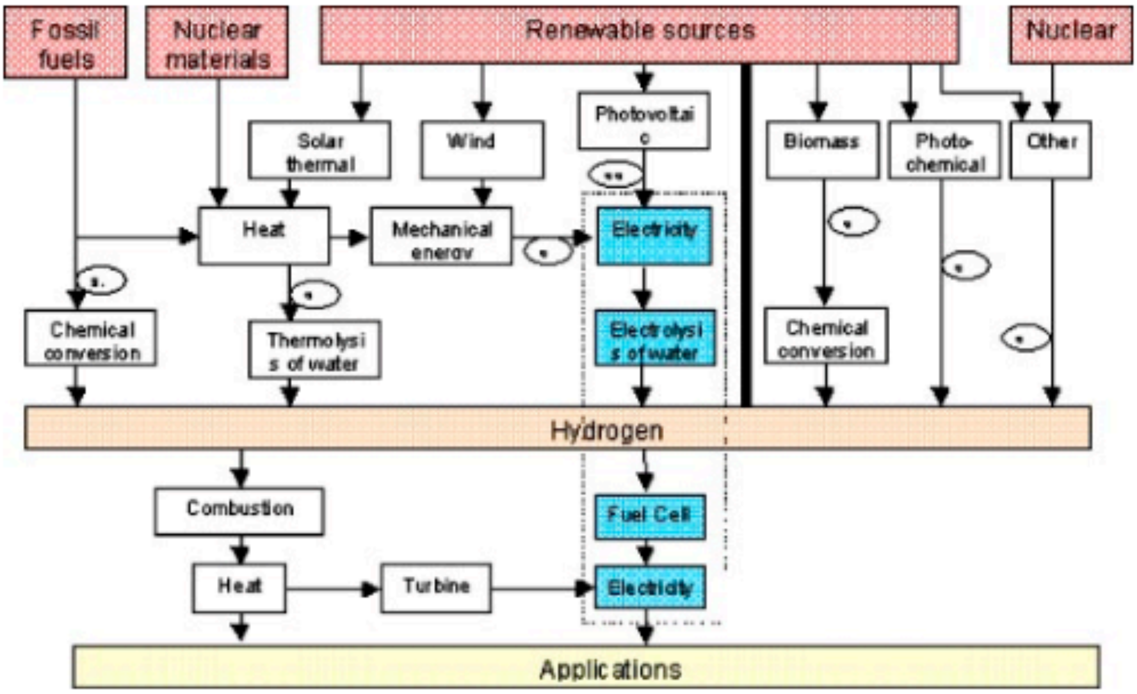
Hydrogen can be produced from electricity by the electrolysis of water, which may be an effective way to store excess production of variable renewable energy.

Hydrogen can be stored in tanks by compression, and concentrations of 5% or more can be injected directly into the natural gas network. The latter option is attractive because existing pipelines and gas storage facilities can be used, and a substantial quantity of energy can be stored without expanding existing facilities or incurring additional expense. Otherwise, bulk storage of hydrogen can be achieved by chemical conversion to methane or ammonia. Methane is the main component of natural gas and can be stored directly in the natural gas network; the process of methanation is also a method for capturing CO_2 (Schaaf et al. 2014). A project in Western Australia is testing the feasibility of exporting solar energy stored by converting hydrogen to ammonia (Want and Cooper 2014).

Hydrogen can be converted back into electricity using fuel cells, or by combustion in suitable turbines. MW-scale electrolysers are available for grid-scale applications but there is not yet a mature supply chain. Hydrogen can be combusted directly or after conversion to methane or ammonia in turbines that have been suitably modified.

Because multiple conversion steps are involved in any hydrogen pathway, the overall round-trip efficiency of electricity stored as hydrogen is low.

Figure 24 Hydrogen pathways highlighting electricity storage

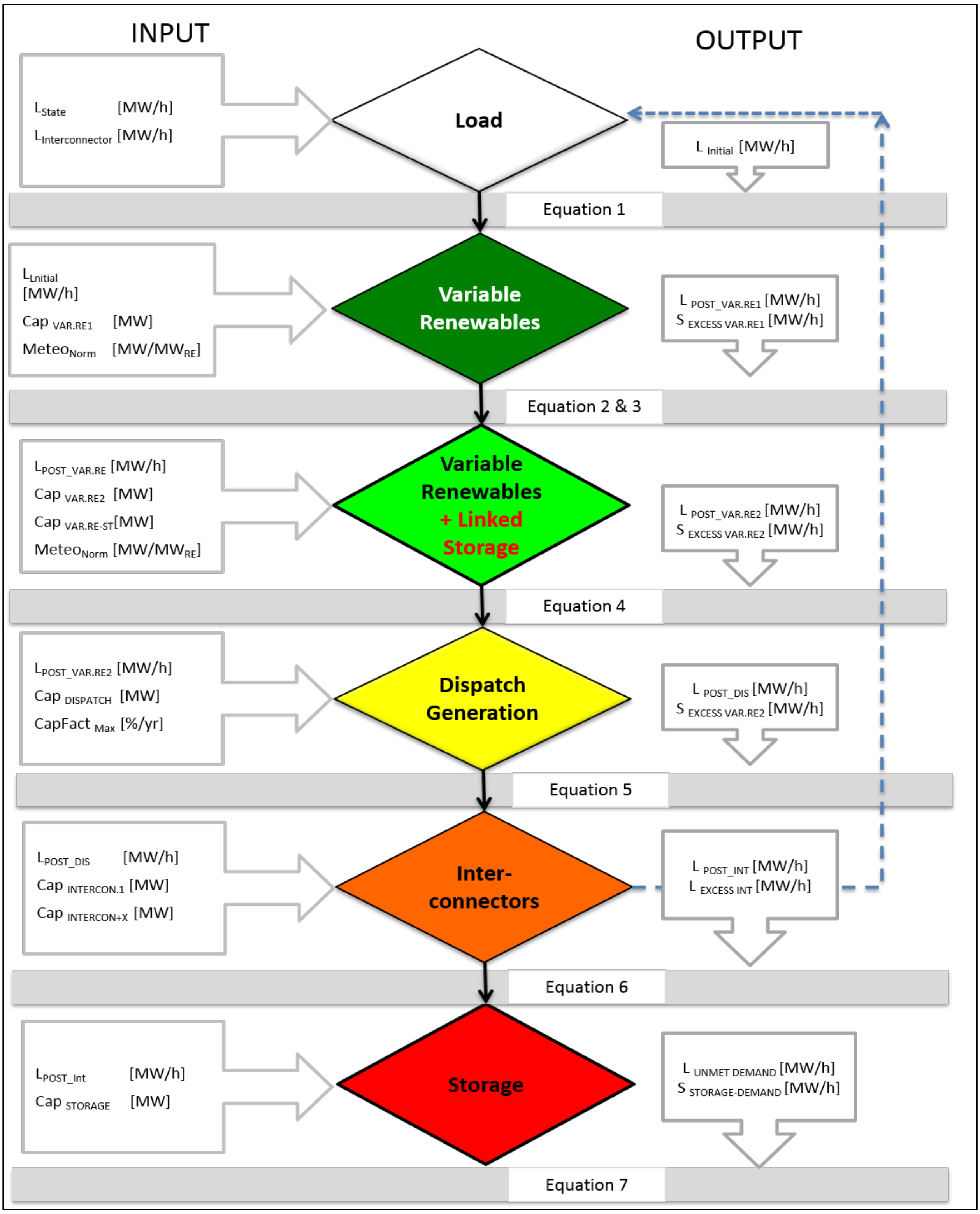


Molten salt thermal storage

Molten salts are solid at room temperature and atmospheric pressure, but become liquid when heated (IEA-ETSAP and IRENA, 2013). Molten salt is often used to store heat in concentrated solar thermal facilities for use in generating electricity (AECOM 2015). This allows solar thermal power plants to dispatch electricity when it is required. As electricity is required, molten salt is dispatched from the storage tank through a heat exchanger to create steam, which powers a conventional steam turbine. Molten salt storage is often combined with Concentrated Solar Thermal (CST), which uses reflectors to convert sunlight into concentrated heat energy (IEA-ETSAP and IRENA 2013). Concentrated Solar Thermal is a proven technology which was first implemented in California in 1984.

Appendix 2 Detailed calculations

All calculations are done on an hourly basis for each hour of the year, and the final results are the sum of the hourly outputs. The equations in the model diagram are detailed below.



Equation 1: Initial Load

$$L_{INITIAL} = L_{State} + L_{Interconnector} \quad [MW]$$

with:

L_{State}: Load of particular state (QLD, NSW, VIC, TAS, SA, SWIS) [MW]

$L_{Interconnector}$: Load from interconnected state(s) connected to interconnector [MW]

Equation 2: Load after variable renewable supply

$$L_{POST\_VAR.RE1} = L_{INITIAL} - C_{VAR1} \quad [MW]$$

WHERE

$$C_{VAR1} = C_{VAR.Wind} * METEO_{Wind} + C_{VAR.PVU} * METEO_{PVU} \quad [MW]$$

with:

C_{var1} Capacity of wind and utility scale solar PV [MW]

$C_{VAR.PVU,\ VAR.WIND}$ Installed capacity utility scale PV or wind [MW]

$METEO_{PVU,\ wind,\ CST,\ rooftop}$ Normalised output from utility PV, wind, CST, or rooftop PV for calculation hour [MW/MW$_{Installed}$]

$S_{PEXCESS\_VAR.RE1}$: variable RE generation in excess to instantaneous demand after wind and utlity PV [MW]

Equation 3: Excess renewable supply after wind and utility solar PV

IF $C_{var1} <= L_{INITIAL}$, $S_{PEXCESS\_VAR.RE1} = 0$, *otherwise*

$$S_{EXCESS\_VAR.RE1} = C_{VAR1} - L_{INITIAL} \quad [MW]$$

with:

C_{var1} Capacity of wind and utility scale solar PV [MW]

$S_{PEXCESS\_VAR.RE1}$: variable RE generation in excess to instantaneous demand after wind and utlity PV [MW]

When variable renewable supply exceeds instantaneous load, surplus renewable power generation will flow through the model, and will comprise an input to both the storage calculation and the interconnector calculation (if relevant). Without storage, all this renewable energy would be curtailed.

Equation 4: Load after variable renewable supply with integrated storage

If $C_{VAR.ROOFTOP} * METEO_{ROOFTOP} > 0$,

$$L_{POST\_VAR.RE2} = L_{POST\_VAR.RE1} - METEO_{ROOFTOP} \times CAP_{ROOFTOP}$$

OTHERWISE

$$L_{POST\_VAR.RE2} = L_{POST\_VAR.RE1} - ST_{DIS},$$

WHERE

$$ST_{DIS\ x} = MIN\ (ST_x * \eta_{SYSTEM},\ L_{UNMET},\ CAP_{Storage}) \qquad [MWh]$$

The energy into storage ST_{CH} at hour x is zero if there are no excess generation from rooftop PV, if the storage is discharging to meet load (which takes priority), or if the storage is fully charged. If none of these conditions are met:

$$ST_{Ch\ x} = MIN\ (Cap_{Storage},\ S_{PEXCESS\_VAR.RE.INT}) \qquad [MWh]$$

The energy out of storage ST_{DIS} at hour x is zero if there ***is*** load being met from rooftop PV directly, or if the storage charge is zero. If none of these conditions is met:

$$ST_{DIS\ x} = MIN\ (ST_x * \eta_{SYSTEM},\ L_{UNMET},\ Cap_{Storage}) \qquad [MWh]$$

The energy out of this variable RE with storage for hour$_x$ is zero if there is no generation.

$$S_{VAR.RE2\_EXCESS} = IF\ L_{POST\_VAR.RE2} > L_{POST\_VAR.RE1},\ ST_{VAR.RE2}) \qquad [MW]$$

$ST_{VAR.RE2}$: *Storage Capacity*

with

$CAP_{Storage}$	Capacity of consumer storage	[MW]
$CAP_{ROOFTOP}$	Capacity of rooftop PV	[MW]
ST_X	Charge held in storage at hour x	[MWh]
$ST_{CH.X}$	Charge into the storage at hour x	[MWh]
$ST_{DIS.X}$	Discharge from the storage at hour x	[MW]
L_{unmet}	Unmet load pre storage (at hour x)	[MW]
η_{SYSTEM}	round-trip efficiency of storage	[%]
$METEO_{rooftop}$:	Normalised output from rooftop PV	[MW/MW$_{Installed}$]
$METEO_{SOLAR}$		
$S_{VAR.RE2\_EXCES}$:	excess renewable supply after PV storage [MW/MW$_{Installed}$]	

If the PV output exceeds load, excess output will be stored within the batteries, to the limits of the energy storage capability of the battery.

Equation 5: Load after dispatchable power generation

Dispatchable generation will only be used if there is unmet load from the previous process, and cannot exceed the load.

$$L_{POST\_DISPATCH} = L_{POST\_VAR.RE2} - (S_{DISPATCH1,} + S_{DISPATCH\ 2} + \ldots + S_{DISPATCH\ x}) \qquad [MW]$$

and

$$S_{DISPATCH1,2,3,\ldots x} = MIN\ ((CAP_{DISPATCH1,2,3,\ldots,x}\ \ CapFact_{MAX1,2,3,\ldots,x}),\ L) \qquad [MW]$$

with:

$S_{DISPATCH1,2,3,\ldots x}$	Generation from dispatchable power plants	[MWh]
$CAP_{DISPATCH\ 1,2,3\ldots,x}$:	Installed capacity dispatch power plant	[MW]
$CapFact_{MAX}$:	Maximum utilisation	[%/year]

Equation 6: Load and supply from interconnectors

The potential contribution from interconnectors is calculated from the interconnector capacity, the unmet load after the last dispatchable generation, and the potential generation from the connected state. For the interconnector from state A to state B:

$$S_{interconnector\_A} = Min\ (L_{post\_dispatch\_B},\ S_{PEXCESS\_VAR.RE2\_A} + S_{DISPATCH\_EXCESS\_A},\ CAP_{INT\_A\_B})\ \text{[MW]}$$

and

$$L_{interconnector\_B} = Min\ (L_{POST\_DISPATCH\_B},\ S_{interconnector\_A},\ CAP_{INT\_A\_B})$$

then:

$$L_{POST\_INTERCON\_A} = L_{POST\_DISPATCH\_B} - (S_{INTERCONNECTOR\_A}) \qquad [MW]$$

with

$S_{interconnector\_A}$	Supply via interconnector from state A to State B	[MW]
$L_{post\_dispatch\_B}$,	Load after dispatchable generation in State B	[MW]
$S_{PEXCESS\_VAR.RE2\_A}$	Excess RE generation from State A	[MW]
$S_{DISPATCH\_EXCESS\_A}$	Spare dispatchable generation capacity State A	[MW]
$CAP_{INT\_A\_B}$	Capacity of interconnector from State A to State B	[MW]

Note that the load from each relevant interconnector is added into Equation 1 (initial load), and Equation 6 is repeated for each relevant interconnector. The load from the import state is set as a limit to equal to the supply from the interconnector to prevent excess RE from one state being double-counted in the import state.

Equation 7: Storage charge, discharge, and load met from storage

If there is load, and there is charge in the storage, then

$$ST_{DIS\ x} = MIN\ (ST_x * \eta_{SYSTEM},\ L_{UNMET},\ Cap_{Storage}) \qquad \text{[MWh]}$$

The state of charge at hour x is:

$$ST_x = ST_{x-1} + (ST_{Ch\_RE\ x} + ST_{Ch\_DIS\ x} - ST_{DIS\ x})$$

when

The energy into storage from variable renewable energy ST_{CH_RE} at hour x is zero if any of the following conditions is met: if the storage is discharging to meet load (which takes priority), if there are no excess renewables or if the storage is fully charged ($STx = MWh_{STORAGE}$). If none of these conditions are met, then:

$$ST_{Ch\_RE\ x} = MIN\ (Cap_{Storage},\ S_{PEXCESS\_VAR.RE.INT}) \qquad \text{[MWh]}$$

The energy into storage from dispatchable energy ST_{CH_DIS} at hour x is zero if any of the following conditions is met: if the storage is discharging to meet load (which takes priority), if there is variable RE supply at any point from hour x to hour (x + 24), if there is no spare dispatchable capacity after the interconnectors, or if the storage is fully charged. If none of these conditions are met, then:

$$ST_{Ch\_DIS\ x} = MIN\ (Cap_{Storage},\ S_{DISPATCH\_EXCESS}) \qquad [MWh]$$

The unmet demand post storage is equal to:

$$L_{POST\_STORAGE\_x} = L_{UNMET\_x} - ST_{DIS\ x} \qquad [MW]$$

with

$MWh_{STORAGE}$	Maximum energy which may be stored	[MWh]
ST_X	Charge held in storage at hour x	[MWh]
$ST_{CH.X}$	Charge into the storage at hour x, from either variable RE or dispatchable generation	[MW]
$ST_{DIS.X}$	Discharge from the storage at hour x	[MW]
$S_{PEXCESS\_VAR.RE.INT}$	Excess RE supply after interconnects at hour x	[MW]
$S_{DISPATCH\_EXCESS}$	Spare dispatchable generation capacity at hour x	[MW]
L_{UNMET_x}	Unmet load pre storage (at hour x)	[MW]
$L_{POST\_STORAGE}$	Unmet load pre storage (at hour x)	[MW]
$Cap_{storage}$	Capacity of storage	[MW]
η_{SYSTEM}	round-trip efficiency of storage	[%]

Appendix 3 AEMO generation information by state

The existing, committed, and proposed generation by state were downloaded from the AEMO website (Australian Energy Market Operator (AEMO) 2016a) in December 2016, using the updates provided by AEMO on 18 November 2016. These are reproduced below, with an additional line of the assumed withdrawal of coal plants under the high renewables scenario. Note that these figures do not include rooftop solar.

NSW	Coal	CCGT	OCGT	Gas other	Solar*	Wind	Water	Biomass	Other	Total
Existing	10,240	591	1,530	147	231.1	666	2,745	131	9.1	16,289
Announced Withdrawal	2,000	171	0	0	0.0	0	0	0	0	2,171
Existing less Announced Withdrawal	8,240	420	1,530	147	231.1	666	2,745	131	9.1	14,119
Committed	0	0	0	0	23.0	175	0	0	0	198
Proposed	0	15	500	0	211.6	4,723	0	8	0	5,458
Coal retirement Paris RE	-1,320	Vales Point is assumed to close								
Coal retirement HIGH RE	-6,840	Vales Point B, Eraring, Bayswater are assumed to close								

VIC	Coal	CCGT	OCGT	Gas other	Solar*	Wind	Water	Biomass	Other	Total
Existing	6,230	21	1,904	523	0	1,249	2,296	53	0	12,276
Announced Withdrawal	1,600	0	0	0	0	0	0	0	0	1,600
Existing less Announced Withdrawal	4,630	21	1,904	523	0	1,249	2,296	53	0	10,676
Committed	0	0	0	0	0	306	0	0	0	306
Proposed	0	500	600	0	164	3,449	34	0	0	4,747
Coal retirement Paris RE	-1,450	Yallourn W is assumed to close								
Coal retirement HIGH RE	-4,630	Yallourn W, Loy Yang A, Loy Yang B are assumed to close								

SA	Coal	CCGT	OCGT	Gas other	Solar*	Wind	Water	Biomass	Other	Total
Existing	0	419	915	1,280	0	1,595	3	21	129	4,362
Announced Withdrawal	0	0	0	0	0	0	0	0	0	0
Existing less Announced Withdrawal	0	419	915	1,280	0	1,595	3	21	129	4,362
Committed	0	0	0	0	0	102	0	0	0	102
Proposed	0	200	320	0	702	2,951	0	20	0	4,193
Withdrawn	-786	-239	0	0	0	0	0	0	0	-1,025

QLD	Coal	CCGT	OCGT	Gas other	Solar*	Wind	Water	Biomass	Other	Total
Existing	8,216	1,213	1,894	187	0	12	664	367	1	12,555
Announced Withdrawal	0	0	34	30	0	0	0	0	0	64
Existing less Announced Withdrawal	8,216	1,213	1,860	157	0	12	664	367	1	12,491
Committed	0	0	0	0	28	0	0	0	0	28
Proposed	0	0	2,545	0	646	990	0	158	0	4,338
Withdrawn	0	-385	0	0	0	0	0	0	0	-385
Coal retirement Paris RE	-3,780	Gladstone, Tarong, Callide B are assumed to close								
Coal retirement HIGH RE	-5,240	Gladstone, Tarong, Callide B, Stanwell B are assumed to close								

TAS	Coal	CCGT	OCGT	Gas other	Solar*	Wind	Water	Biomass	Other	Total
Existing	0	0	178	0	0	308	2,281	5	0	2,772
Announced Withdrawal	0	0	0	0	0	0	0	0	0	0
Existing less Announced Withdrawal	0	0	178	0	0	308	2,281	5	0	2,772
Committed	0	0	0	0	0	0	0	0	0	0
Proposed	0	0	0	0	0	329	0	0	0	329
Withdrawn	0	-208	0	0	0	0	0	0	0	-208

SWIS	Coal	CCGT	Gas/gas & diesel peaking	Gas other	Solar*	Wind	Water	Biomass	Other	Total
Existing	1,778	876	1,242	880	4	86	0	16	176	5,058
Announced Withdrawal	340									340
Existing less Announced Withdrawal	1,438	876	1,242	880	4	86	0	16	176	4,718
ADDITIONAL INFORMATION (not from AEMO)										
Proposed					100 [1]	500 [2]				600
Coal retirement Paris RE	-874	Muja is assumed to close								
Coal retirement HIGH RE	-874	Muja is assumed to close								

Note 1: 100 MW Cunderdin Solar
Note 2: 100 MW Pacific Hydro proposal for Lancelin; http://www.pacifichydro.com.au/english/projects/development-construction/nilgen-wind-farm/; 300 MW Dandaragan http://dandaraganwindfarm.com.au/; 100 MW Badgingarra

Appendix 4 Final energy mix per scenario

CAPACITY: 2017		Total	NSW	QLD	SA	TAS	VIC	SWIS
Photovoltaic - roof top	MW	**5,356**	1,197	1,790	740	95	969	564
Photovoltaic - utility	MW	**1,941**	1,197	0	740	-	-	4
Wind - onshore	MW	**3,917**	666	12	1,595	308	1,249	86
CSP	MW	**0**	-	-	-	-	-	-
Bioenergy	MW	**592**	131	367	21	5	53	16
Hydro power	MW	**7,988**	2,745	664	3	2,281	2,296	-
Gas OGCT	MW	**7,663**	1,530	1,894	915	178	1,904	1,242
Gas	MW	**6,137**	738	1,400	1,699	-	544	1,756
Coal	MW	**26,464**	10,240	8,216	-	-	6,230	1,778
Total	**MW**	**60,058**	**18,443**	**14,344**	**5,713**	**2,867**	**13,245**	**5,446**

CAPACITY: BAU RE (2030)		Australia	NSW	QLD	SA	TAS	VIC	SWIS
Photovoltaic – roof top	MW	**16,847**	4,123	5,178	1,840	356	3,636	1,715
Photovoltaic - utility	MW	**5,768**	4,123	674	702	-	164	104
Wind - onshore	MW	**9,495**	3,203	507	1,697	473	3,280	336
CSP	MW	**0**	-	-	-	-	-	-
Bioenergy	MW	**778**	139	525	41	5	53	16
Hydro power	MW	**8,022**	2,745	664	3	2,281	2,330	-
Gas OGCT	MW	**9,612**	1,780	3,133	1,075	178	2,204	1,242
Gas	MW	**6,294**	575	1,370	1,799	-	794	1,756
Coal	MW	**22,524**	8,240	8,216	-	-	4,630	1,438
Total	**MW**	**79,339**	**24,927**	**20,266**	**7,157**	**3,292**	**17,090**	**6,607**

CAPACITY: PARIS RE (2030)		Australia	NSW	QLD	SA	TAS	VIC	SWIS
Photovoltaic - roof top	MW	**16,847**	4,123	5,178	1,840	356	3,636	1,715
Photovoltaic - utility	MW	**8,580**	4,123	1,320	1,404	-	328	1,404
Wind - onshore	MW	**19,538**	7,926	1,298	1,697	802	6,728	1,086
CSP	MW	**0**	-	-	-	-	-	-
Bioenergy	MW	**778**	139	525	41	5	53	16
Hydro power	MW	**8,022**	2,745	664	3	2,281	2,330	-
Gas OGCT	MW	**9,612**	1,780	3,133	1,075	178	2,204	1,242
Gas	MW	**6,294**	575	1,370	1,799	-	794	1,756
Coal	MW	**15,800**	6,920	5,136	-	-	3,180	564
Total	**MW**	**85,470**	**28,331**	**18,623**	**7,859**	**3,621**	**19,253**	**7,783**

CAPACITY: HIGH RE (2030)		Australia	NSW	QLD	SA	TAS	VIC	SWIS
Photovoltaic - roof top	MW	**22,870**	5,680	6,949	2,561	475	4,774	2,431
Photovoltaic - utility	MW	**18,846**	5,680	5,966	1,404	-	2,492	3,304
Wind - onshore	MW	**24,000**	10,760	1,793	1,697	900	7,763	1,086
CSP	MW	**6,000**	2,500	1,500	-	-	1,000	1,000
Bioenergy	MW	**1,428**	489	525	41	5	253	116
Hydro power	MW	**8,022**	2,745	664	3	2,281	2,330	-
Gas OGCT	MW	**9,612**	1,780	3,133	1,075	178	2,204	1,242
Gas	MW	**6,294**	575	1,370	1,799	-	794	1,756
Coal	MW	**4,787**	1,400	2,976	-	-	-	411
Total	**MW**	**101,859**	**31,608**	**24,875**	**8,580**	**3,839**	**21,610**	**11,346**

Table 23 Coal fired power stations by state in the PARIS RE and HIGH RE scenarios

	RETIRED		REMAINING	
	MW	**Power station**	**MW**	**Power station**
NEW SOUTH WALES				
HIGH RE	6840	Vales Point B, Eraring, Bayswater	1400	Mt Piper
PARIS RE	1320	Vales Point B	113	Bayswater, Eraring, Mt Piper
VICTORIA				
HIGH RE	4630	Yallourn W, Loy Yang A, Loy Yang B	0	-
PARIS RE	1450	Yallourn W	5140	Loy Yang A, Loy Yang B
QUEENSLAND				
HIGH RE	5240	Gladstone, Tarong, Callide B, Stanwell	2946	Callide C, Kogan Creek, Millmerran, and Tarong North
PARIS RE	3780	Callide B, Gladstone and Tarong	4406	Callide C, , Kogan Creek, Millmerran, 1460, Tarong North
SWIS				
HIGH Re	874	Muja C & D	972	Bluewaters 1, Bluewaters 2, Collie Power Station, Muja A & B (refurbished)
PARIS RE	874	Muja C & D	972	Bluewaters 1, Bluewaters 2, Collie Power Station, Muja A & B (refurbished)

Appendix 5 Polygon weightings for solar and wind traces

NSW data

Polygon	Build limit solar (GW)	Solar weighting	Build limit wind (GW)	Wind weighting
21	706	0.126477965	1.5	0.007832898
22	1004	0.179863848	0	0
23	906	0.162307417	1.1	0.005744125
24	96	0.017198137	77.5	0.404699739
28	718	0.128627732	7.8	0.04073107
29	564	0.101039054	0.3	0.00156658
30	400	0.071658904	0.4	0.002088773
31	24	0.004299534	35	0.182767624
33	410	0.073450376	0	0
34	474	0.084915801	0	0
35	260	0.046578287	0.6	0.003133159
36	20	0.003582945	67.3	0.351436031

QLD data

Polygon	State	Build limit solar (GW)	Solar weighting	Build limit wind (GW)	Wind weighting
1	QLD	102	0.012303981	53.5	0.354304636
2	QLD	822	0.099155609	0	0
3	QLD	166	0.020024125	24.6	0.162913907
4	QLD	204	0.024607961	4.3	0.028476821
5	QLD	1030	0.12424608	10.4	0.068874172
6	QLD	1092	0.13172497	1	0.006622517
7	QLD	220	0.026537998	4.6	0.030463576
8	QLD	782	0.094330519	1.7	0.011258278
9	QLD	504	0.06079614	0	0
10	QLD	134	0.016164053	2.7	0.017880795
11	QLD	36	0.004342581	1	0.006622517
14	QLD	1026	0.123763571	20.2	0.133774834
15	QLD	1148	0.138480097	0	0
16	QLD	838	0.101085645	0	0
17	QLD	186	0.022436671	27	0.178807947

SA data

Polygon	State	Build limit solar (GW)	Solar weighting	Build limit wind (GW)	Wind weighting
12	SA	374	0.100160686	1.4	0.007621121
13	SA	574	0.15372255	0.6	0.003266195
18	SA	428	0.114622389	0.1	0.000544366
19	SA	496	0.132833423	0	0
20	SA	490	0.131226567	32.7	0.178007621
25	SA	62	0.016604178	2.2	0.011976048
26	SA	378	0.101231923	47.9	0.260751225
27	SA	528	0.141403321	85.5	0.465432771
32	SA	404	0.108194965	13.3	0.072400653

TAS data

Polygon	State	Build limit solar (GW)	Solar weighting	Build limit wind (GW)	Wind weighting
39	TAS	10	0.331564987	7.6	0.207084469
40	TAS	16	0.530503979	9.4	0.25613079
41	TAS	0.16	0.00530504	0.3	0.008174387
42	TAS	4	0.132625995	19.4	0.528610354

VIC data

Polygon	State	Build limit solar (GW)	Solar weighting	Build limit wind (GW)	Wind weighting
37	VIC	514	0.611904762	6.1	0.261802575
38a	VIC	60	0.071428571	6.8	0.291845494
38b	VIC	266	0.316666667	10.4	0.446351931

Appendix 6 Primary research – batteries

Product Name	Battery Type	Price	Nominal Storage (kWh)	Price (AUD$/ kWh)	Usable Storage (kWh)	Power (kW)	Cycle Life	Depth of Discharge (%)	Round Trip Efficiency	Warranty (years)
Batteries without inverters										
Redflow Zcell	Zn-Br	$12,600	10	$1,260	10	3	3,650	100	80%	10
Leclanche Apollion Cube	Li-Ion (1)	$9,200	6.7	$1,373	5.4	3.3	5,000	80	97%	7
BMZ ESS3.0	Li-Ion (1)	$7,700	6.74	$1,142	5.4	8	5,000	80	97%	10
ELMOFO E-Cells ALB52-106	Li-Ion	$8,190	5.5	$1,489	4.4	5	8,000	80	96%	10
Akasol neeoQube	Li-Ion	$12,000	5.5	$2,182	4.95	5	7,000	90	98%	10
LG Chem RESU 6.5	Li-Ion	$6,600	6.5	$1,015	5.9	4.2	3,200	90	95%	10
Delta Hybrid E5	Li-Ion	$8,500	6	$1,417	4.8	3	6,000	80	90%	5
Fronius Solar Battery	Li-Ion (2)	$15,550	12	$1,296	9.6	4	8,000	80	>90%	5
DCS PV 5.0	Li-Ion (2)	$5,900	5.12	$1,152	5.12	5	5,000	100	99%	10
Pylontech Extra2000 LFP	Li-Ion (2)	$1,999	2.4	$833	1.92	2	4,000	80	TBC	5
Batteries with inverters										
GCL E-KwBe 5.6	Li-Ion (3)	$7,500	7	$1,071	5.6	3	2,000	80	95%	7
Enphase AC Battery	Li-Ion (4)	$2,000	1.2	$1,667	1.14	0.26	7300	95	96%	10
Tesla Powerwall 2 (AC)	Li-Ion	$8,800	13.2	$667	13.2	5	n/a	100	89%	10
Panasonic LJ-SK84A	Li-Ion	$11,900	8	$1,488	8	2	3650	100	93%	10 - 7

Product Name	Battery Type	Price	Nominal Storage (kWh)	Price (AUD$/ kWh)	Usable Storage (kWh)	Power (kW)	Cycle Life	Depth of Discharge (%)	Round Trip Efficiency	Warranty (years)
Samsung ESS AIO	Li-Ion (5)	$12,000	7.2	$1,667	6.48	4	6,000	90	95%	5
BYD Mini ES	Li-Ion (2)	$8,400	3.75	$2,240	3	3	6000	80	98%	10
Tesla Powerwall 2 (DC)	Li-Ion	$8,800	13.5	$652	13.5	5	n/a	100	91.80%	10
PowerOak ESS	Li-Ion	$13,050	12	$1,088	9.8	3	6,000	80	TBD	5
Sunverge SIS	Li-Ion	$26,000	11.6	$2,241	9.86	5	8,000	85	96%	10
Sonnenbatterie	Li-Ion (2)	$6,700	2	$3,350	2	1.5	10,000	100	93-96% (7)	10
ZEN Freedom Powerbank FPB16	Li-Ion (2)	$21,750	16	$1,359	14.4	5	6,000	90	TBD	5
SolaX BOX	Li-Ion (2)	$7,700	4.8	$1,604	3.84	4.6	4,000	80	97%	5
SolaX BOX	Li-Ion (2)	$11,385	14.4	$791	11.52	5	4,400	80	97%	5
Alpha-ESS STORION S5	Li-Ion (2)	$7,200	3	$2,400	2.7	5	8,000	90	95%	5
Magellan HESS	Li-Ion (6)	$13,000	6.4	$2,031	5.76	5	4,000	90	97%	5

NOTES
1) Li-Ion NMC
2) Lithium Iron Phosphate
3) Lithium Nickel Cobalt Manganese
4) Lithium Ferrite Phosphate
5) Lithium Manganese Oxide
6) Lithium-manganese-cobalt-oxide
7) 93% single phase, 96% three phase

Appendix 7 Detailed inputs to LCOS calculation

LCOS inputs	CAPEX		Depth of Discharge	Annual degradation	Fixed O&M		Variable O&M	Cycles/ yr	Round trip efficiency	Project lifetime
	2017	2030								
Technology	*$/kWh rated*		*%*	*%*	*$/kW/yr (Note 1)*	*$/kWh/yr (Note 1)*	*$/kWh throughput/ year*	*Min*	*%*	*years*
Advanced Lead Acid Battery	680	320	45%	1.48%	4.8	2.4	0.0048	220	94%	15
Li-Ion	699	333	100%	1.48%	9.8	4.9	0.0030	220	93%	15
Zn-Br Flow Battery	1300	272	100%	1.48%	6.1	3.1	0.0009	220	75%	15
Pumped Hydro Storage (lower cost)	408		100%	negligible	6.5	0.5	0.0003	220	76%	40
Pumped Hydro Storage (higher cost)	979		100%	negligible	6.5	1.8	0.0003	220	76%	40
Compressed Air Energy - Underground Storage (diabatic)	162		100%	negligible	5.5	0.5	0.0044	220	134% Note 2	40
Hydrogen Energy Storage	372		100%	negligible	36.4	6.7	0.0043	220	40%	20
CST - molten salt	490		100%	negligible	n/a	n/a	0.0150	220	100%	25

Note 1: $/ KW fixed O&M is converted from $/kW to $/KWh storage capacity by using the following storage capacities: 2 kWh/ KW for the three battery types, 12.3 kWh/ kW and 3.7 kWh/ kW for the lower and higher cost hydro respectively (derived from Winch et al, 2012), and 11 kWh/ KW for CAES (average of the two plants in operation). Fixed O&M for the power to gas system is calculated as 1.81% of CAPEX (from Julch, 2016), using the CAPEX values from from Zakeri, 2015.

Note 2: while the round trip efficiency for energy for CAES is 47 %, the round trip efficiency for electricity alone is 134%, as round trip efficiency is defined as the ratio of electricity in to electricity out. The reason it is more than 100% is because of the gas input.

Appendix 8 Interconnector capacities for sensitivity analysis

	Initial value	Value for sensitivity analysis
NSW to Qld	407 MW	814 MW
QLD to NSW	1,288 MW	2,576 MW
NSW to VIC	1,350 MW	2,700 MW
VIC to NSW	1,600 MW	3,200 MW
SA to VIC	850 MW	1,700 MW
VIC to SA	870 MW	1,740 MW
VIC to TAS	478 MW	956 MW
TAS to VIC	594 MW	1,188 MW

Appendix 9 BAU RE – results by state

Table 24 BAU RE scenario results by state (2030)

BAU RE (2030)		TOTAL	NSW	QLD	SA	TAS	VIC	SWIS
Demand	GWh/yr	239,134	76,804	62,385	14,441	11,100	51,036	23,368
UNMET DEMAND BEFORE STORAGE								
After generation	GWh/yr	17	15	-	-	-	0.1	1.8
After interconnectors	GWh/yr	1.8	0.0	-	-	-	-	1.8
Hours with deficit	hours/yr	8	0	-	-	-	-	8.0
STORAGE DEMAND AND EXCESS RENEWABLES								
Additional storage demand	**GWh**	**1.5**	**-**	**-**	**-**	**-**	**-**	**1.5**
	GW	**0.4**	**-**	**-**	**-**	**-**	**-**	**0.4**
Potential curtailment	GWh/yr	1,292	-	-	1,283	-	9	-
	%	1%	-	-	12%	-	-	-
GENERATION								
Renewable	GWh	86,787	24,155	17,103	9,567	11,100	20,290	4,572
Coal, gas & diesel	GWh	152,345	52,634	45,297	4,874	0	30,746	18,794
Via interconnectors(1)	GWh	0	15.2	-15.2	-	-0.1	0.1	-
Total		**239,132**	**76,804**	**62,385**	**14,441**	**11,100**	**51,036**	**23,366**
Renewable %		36%	31%	27%	66%	100%	40%	20%
Consumer storage	GWh	5.6	1.2	1.0	0.7	0.1	1.4	1.2

Appendix 10 Supply/ demand balance by state, PARIS RE and HIGH RE

Figure 25 Supply demand balance by state, PARIS RE scenario (2030)

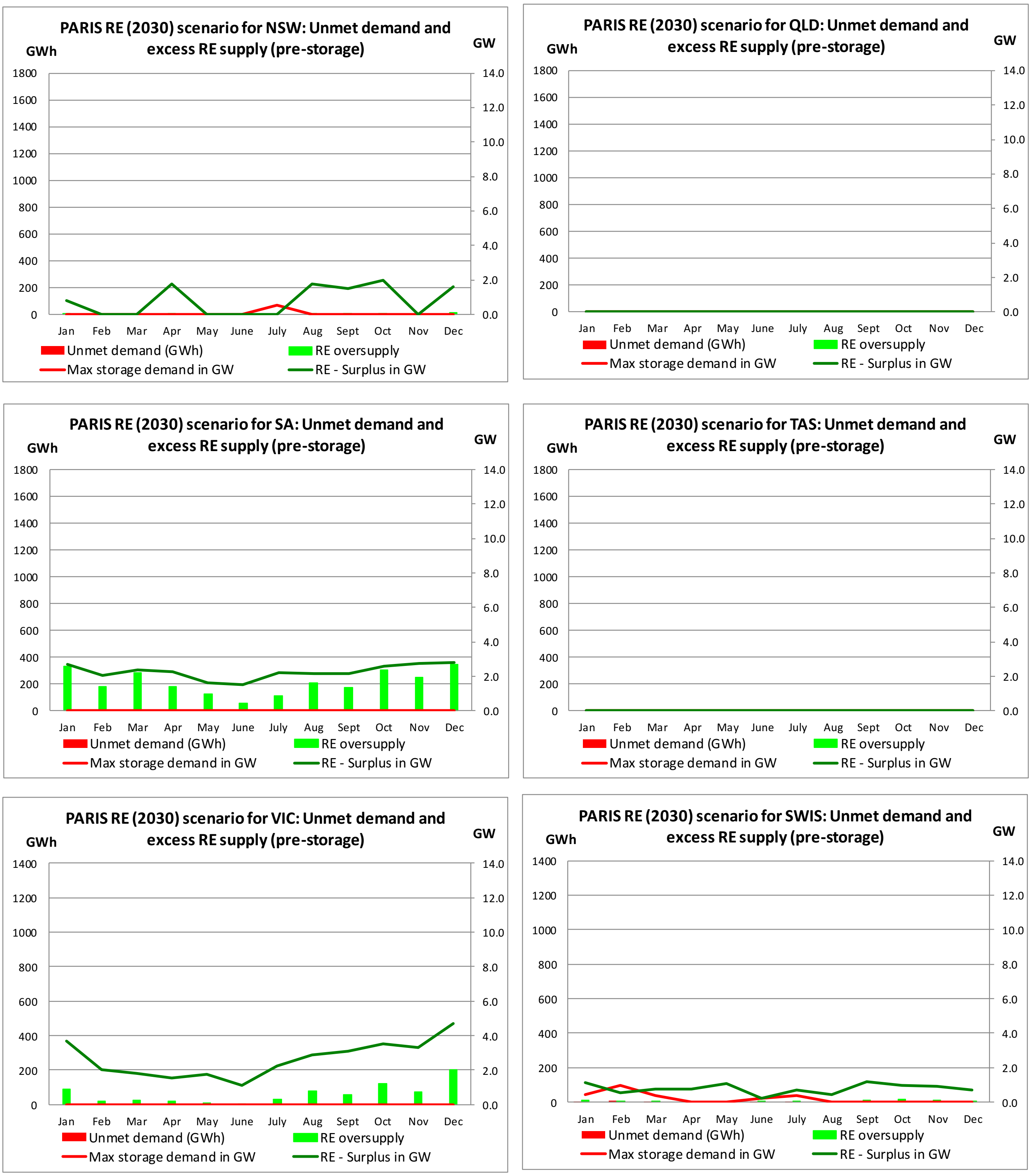
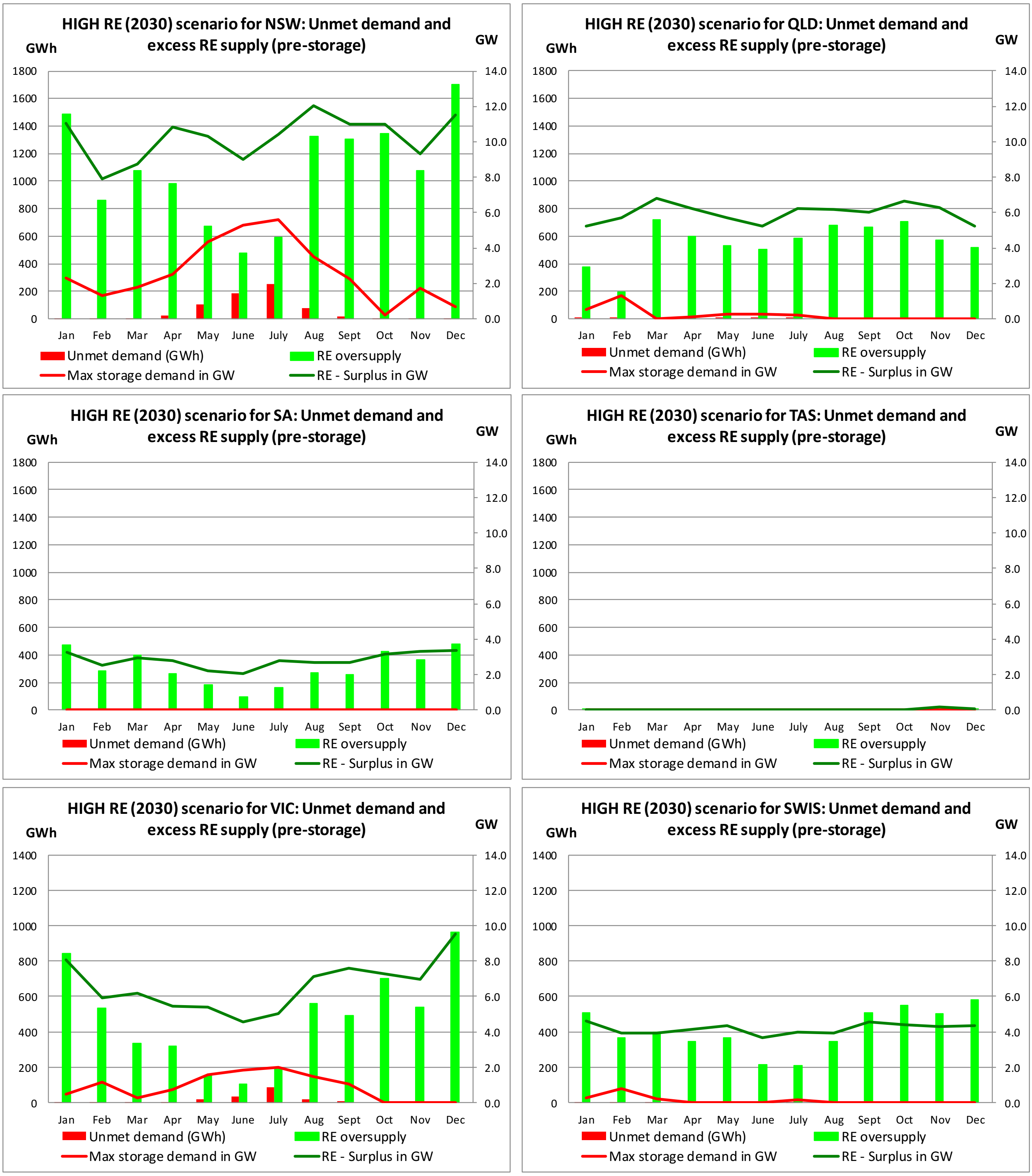


Figure 26 Supply demand balance by state, HIGH RE scenario (2030)



Appendix 11 Normalised wind output by state

Figure 27 Wind output per MW capcity by state and month, 2004-2011