MARSDEN JACOB ASSOCIATES

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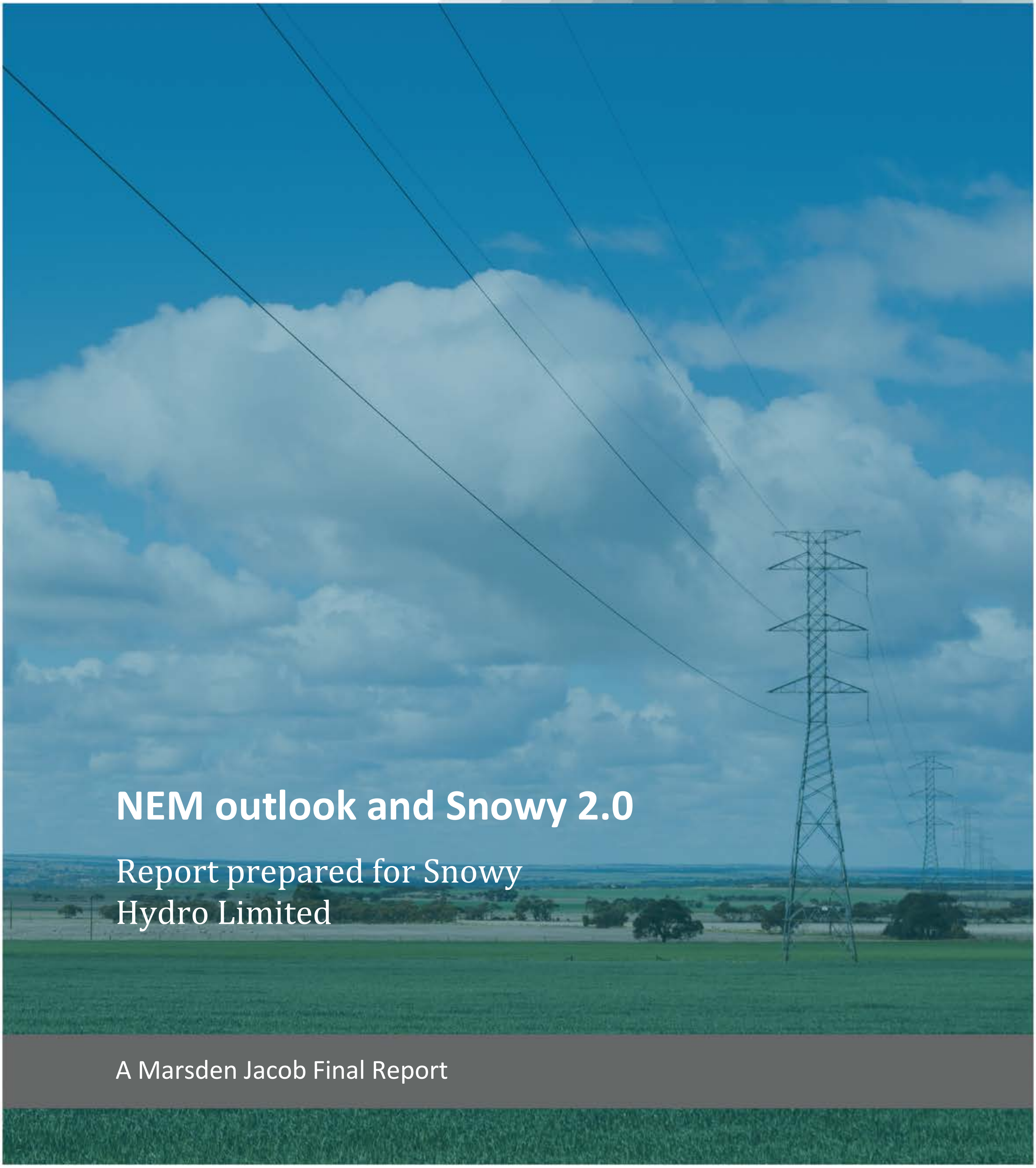

NEM outlook and Snowy 2.0

Report prepared for Snowy Hydro Limited

A Marsden Jacob Final Report

Prepared for Snowy Hydro Limited

Marsden Jacob Associates

ABN 66 663 324 657

ACN 072 233 204

e. economists@marsdenjacob.com.au

Melbourne
Level 4, 683 Burke Road, Camberwell
Victoria 3124 AUSTRALIA
t. 03 9882 1600

Perth
Level 1, 220 St Georges Terrace, Perth Western
Australia, 6000 AUSTRALIA t. 08 9324 1785

Sydney
Rod Carr 0418 765 393

Authors:
Andrew Campbell
Grant Draper
Peter McKenzie
Hana Ramli
Lizzie O'Brien

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Acronyms and abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAES	compressed air energy storage
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
DWP	dispatch weighted price
FCAS	frequency control ancillary services
FOM	fixed operations and maintenance
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
LGC	large-scale generation certificate
LNG	liquefied natural gas
LRET	Large-scale Renewable Energy Target
LRMC	long run marginal cost
MW	megawatt
MWh	megawatt hour
MRMC	mid run marginal cost
NEL	National Electricity Law
NEM	National Electricity Market
NSW	New South Wales
OCGT	open-cycle gas turbine
PJ	petajoule
PV	photovoltaic
RET	Renewable Energy Target
RIT-T	regulatory investment test—transmission
SRAS	System restart ancillary services
SRES	Small-scale Renewable Energy Scheme
SRMC	short run marginal cost
VOM	variable operations and maintenance
VRET	Victorian Renewable Energy Target
WACC	weighted average cost of capital

Executive summary

This report presents the findings of an independent study by Marsden Jacob Associates (Marsden Jacob) of the changing nature of wholesale energy supply in the National Electricity Market (NEM) associated with the increasing penetration of intermittent generation, and the market benefits that would be provided by the development of the proposed Snowy 2.0 scheme.

Snowy 2.0 is a pumped hydro storage scheme to be located in the Snowy Mountains. It would have 2,000 MW of capacity and enough storage to operate continuously for seven days when the storage is full. Cycle losses (the energy required to pump minus the energy returned from generation) would be 24%.

Key findings

A NEM framework that aims to provide increased security, future reliability, lower consumer costs and lower greenhouse gas emissions will require, as one of a number of solutions, large-scale pumped hydro storage. This will stabilise the power grid, lower consumer prices, and enable deeper penetration of currently poorly integrated variable renewable generation as it increases to meet Australia's Paris Agreement commitments and beyond.

Marsden Jacob employed an evaluation framework developed by the Australian Energy Regulator for the purposes of determining the economic benefits Snowy 2.0 would provide to the NEM, termed market benefits.

Marsden Jacob performed modelling to quantify the market benefits that Snowy 2.0 would provide and the impact Snowy 2.0 would have on wholesale energy purchase costs.

We modelled the NEM outcomes under two scenarios of mandated renewable generation entry (labelled 'LRET+VRET Scenario' and 'Long Term (LT) Commitment Scenario') with and without the development of Snowy 2.0. Additional economic renewable generation development above that mandated was allowed in each scenario. In each scenario, the difference between the with and without Snowy 2.0 cases represented the market benefits from developing Snowy 2.0.

The development of scenarios and modelling highlighted the uncertainties involved, particularly the level of battery installation that is influenced by factors that include the need for peaking generation to have fast start capability under 5-minute pricing and retailer and large customer ambitions / incentives to develop renewable generation with storage. The market benefits provided by Snowy 2.0 would increase through additional deferral of battery development.

The market benefits and revenues to Snowy 2.0 were separated into:

- market benefits that Snowy 2.0 operation would provide and energy price reductions to NEM consumers
- the option associated with Snowy 2.0 infrastructure that makes possible additional pumped storage at Snowy (labelled Snowy 3.0), should this be needed in the future due to changing market conditions or

commercial opportunities. This was conservatively estimated on a 25% probability that Snowy 3.0 would be developed.

The results of the modelling, expressed as a present value (in 31 December 2017 Australian dollars) over the period from 2018 to 2074 at a real discount rate of 4.55%, are shown is Table ES1. The range shown for market benefits reflects the uncertainty in battery installation and deferral by Snowy 2.0.

The future market-state in the NEM is built upon the current and known regulatory framework, existing renewable schemes and international emissions agreements, reasonable and known macro assumptions of exiting baseload thermal generation, increasing economics and penetration of large-scale renewables, demand-side management by consumers and the return to a stable market for gas as a reliable fuel source for electricity generation.

Table ES1 Market Benefits and Snowy 2.0 Revenues Present Value $M

Scenario	Market Benefits		
	Excluding Optionality	Option for further development	Total
LRET+VRET	4,272 to 4,738	150	4,423 to 4,889
LT Commitment	6,140 to 6,643	150	6,291 to 6,793

Source: Marsden Jacob, 2017.

The evolving National Electricity Market

The dynamics and the economics of the NEM are becoming more complex as the generation mix moves to more renewable generation, which is characterised by intermittency. The reasons for this transition are environmental (the Paris agreement and beyond), economic (renewable generation costs are decreasing) and ethical (industry and consumer preferences).

Figure ES1 illustrates the change that is occurring. It shows the generation pattern for a typical week in 2017 and that projected in 2025 based on current policies (LRET, VRET and Queensland 50% by 2030). The figure shows generation by fuel type, with the yellow area being large-scale intermittent generation (wind and solar). The demand supplied by the large generators is referred to as 'scheduled demand'.[1] The projected change in the system from 2017 to 2025 is significant.

The rate of change will be influenced by a number of factors, including:

- *legislated large-scale renewable energy policy:* The current LRET and VRET require about a total of 10,000 MW of new large-scale renewable generation to be developed by 2030
- *rooftop PV development:* The development of distributed solar (rooftop PV) generation is projected to continue the strong growth observed over the past few years, with a proportion of those systems having battery storage[2]. There will be approximately an additional 15,700 MW installed by 2036-37
- *closures of coal-fired generators, which currently underpin the supply of electricity in the NEM*: Currently, only about 7,500 MW of coal-fired generation plant is under 30 years old, and a number of closures of coal-fired power stations have been foreshadowed to occur by 2030 and just after. By 2033, it has been

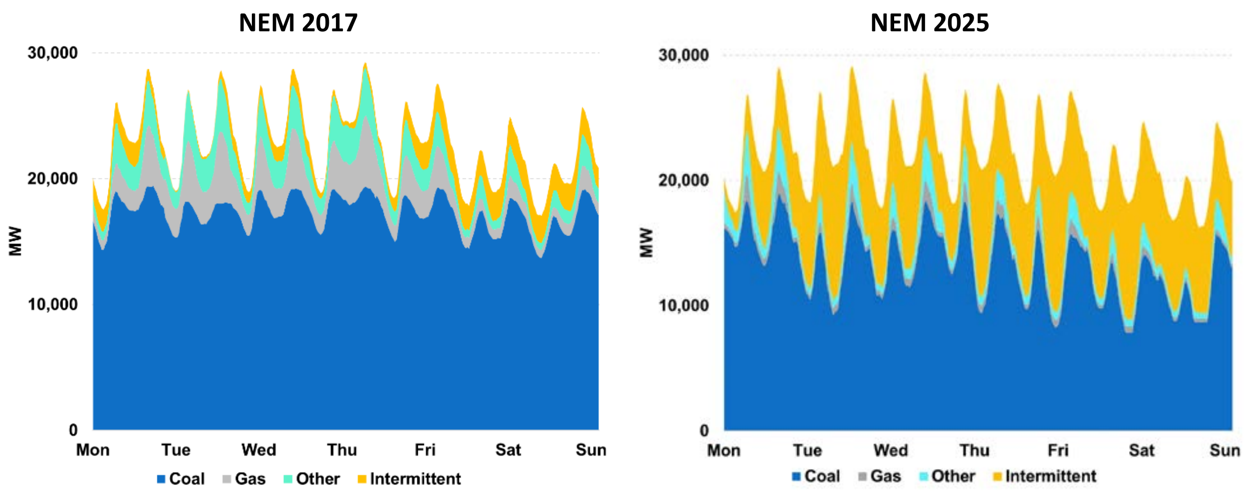
1 Scheduled demand is electricity use less that generated by 'behind the meter' sources such as rooftop PV and other small 'distributed' generation sources.

2 The AEMO projects close to 20% of rooftop PV will have battery storage by 2030: AEMO, Rooftop PV and battery storage, 2016, www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/PV-and-storage.

foreshadowed that over 6,400 MW of coal-fired plant will have been retired in NSW and Victoria. The age and operation of the remaining coal-fired plants indicate that additional plant closures will be likely.

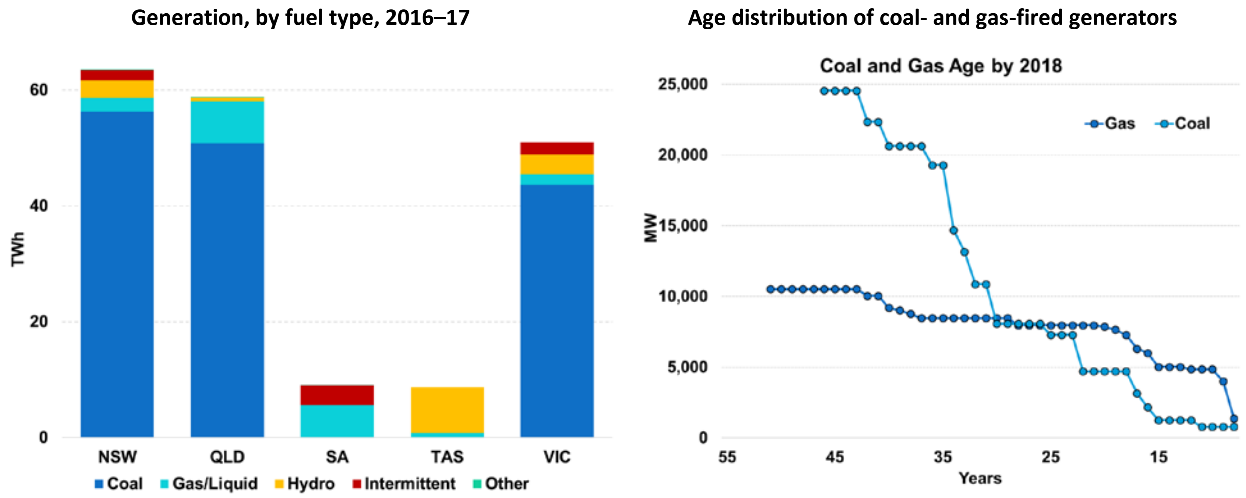
Figure ES2 shows the amount of generation in 2016–17 by fuel type and the age distribution of coal- and gas-fired generators in the NEM in 2017.

Figure ES1: NEM generation, typical week in 2017 and 2025 (projected)



Source: Marsden Jacob, 2017.

Figure ES2: NEM generation, by fuel type, 2016–17, and age of coal and gas generators



Source: Marsden Jacob, 2017.

The outlook is for gas supply in the eastern Australian gas market to be resolved through the development of additional supply. Long-term prices will continue to reflect oil prices, which will recover in the longer term. This has gas prices remaining above $8/GJ, excluding transport.

Uncertainties about future environmental policy and the economics of renewables have led us to identify a range of renewable generation development 'target' scenarios. In each of the scenarios, additional renewable generation would be developed if economic.

The scenarios were:

- *LRET+VRET scenario*: LRET + VRET target met
- *(Long Term) LT Commitment scenario*: LRET + VRET target met, NEM-wide target of 60% supply by renewable generation by 2040 (this includes rooftop PV).

Wholesale market dynamics under increasing intermittent generation

Supply reliability is based on matching generation and demand at all times, and that requires controlled (or dispatchable) generation to be economic and available when required.

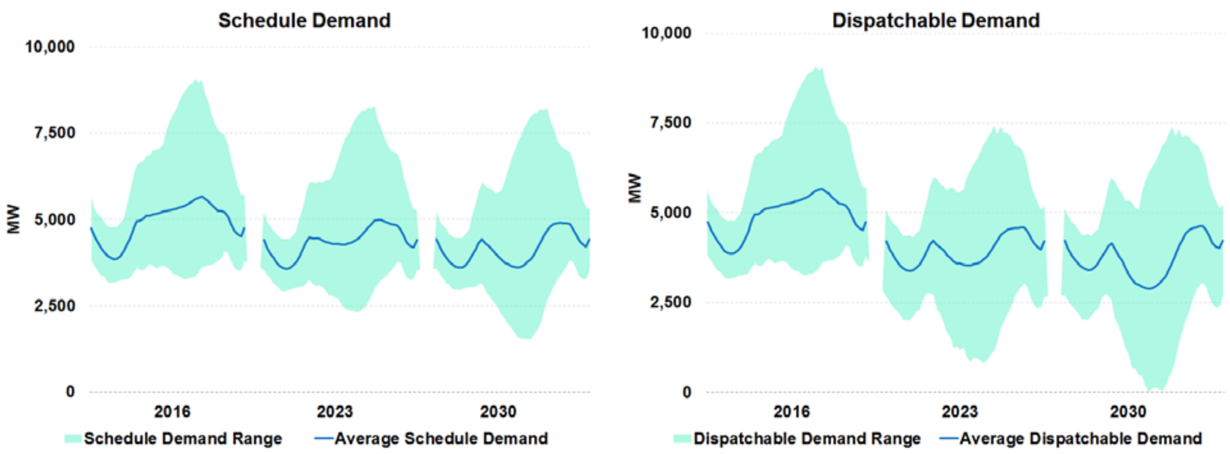
Because renewable generation has very low production costs once built, those generators will run economically before coal- and gas-fired generators. This means that the demand to be supplied by coal- and gas-fired generators will be the residual after low operating cost intermittent generation is dispatched (unless renewable generation is reduced).

The residual demand to be supplied by dispatchable generators has been termed 'dispatchable demand' (defined as scheduled demand less generation from all large-scale renewable generators). The profile of dispatchable demand will increase in volatility as the amount of renewable generation increases.

Based on reasonable projections of the penetration of solar (both rooftop PV and large-scale) and wind generation, by 2030 and on a state-by-state basis, the residual demand supplied by dispatchable generation (that is, coal, gas and hydro) has the potential to vary from near zero (when renewable generation is very high) to very high levels (when renewable generation is very low).

This is demonstrated in Figure ES3, which shows the average daily profile (solid line) and potential variation from that profile (shaded) of scheduled demand and dispatchable demand for 2016 (historical), 2023 (projected) and 2030 (projected). Increased intermittent generation can result in very low demand levels to be met by dispatchable generation, while not significantly decreasing the dispatchable capacity required to supply high demands.

Figure ES3: Profile and spread of scheduled and dispatchable demand – Victorian Summer (MW)



Source: Marsden Jacob, 2017.

Retail market dynamics under increasing intermittent generation

Wholesale energy purchase costs paid by retailers make up approximately 33% of electricity costs to residential consumers, and a larger percentage for commercial and industrial users. The management of energy purchase risk, which is fundamental to retailers' operations, typically involves the purchase of hedging contracts or the development of the retailers' own generation (that is, vertical integration).

At the same time, the proposed move to '5-minute pricing'[3] which will require response times faster than those provided by most peaking generators (such as open-cycle gas turbines), may reduce the capacity of many peaking generators to provide the required contracts. In addition, the closure of coal-fired generators will further reduce the supply of such contracts.

Additional sources of such contracts are foreshadowed to be required in the NEM.

Market development without Snowy 2.0

For the two renewable generation development scenarios, we modelled the NEM on the assumption Snowy 2.0 is not developed. We found as follows:

- intermittency issues will need to be addressed using batteries, peaking generators and coal-fired generators. Batteries will be developed to support the fast response required under 5-minute pricing and to contribute to firming intermittent generation in retailers' portfolios. However open-cycle gas turbine (OCGT) plant is mostly used in this role
- without large-scale storage, no additional renewable generation above the minimum targets will be economic. In the current policy-only scenario (that is, the LRET+VRET scenario), the LRET and VRET are satisfied and no more.

The absence of large-scale storage also meant that not all renewable generation will be usable and there will be wasted renewable generation on days of high wind and solar generation under development given by the LT Commitment scenario.

Snowy 2.0 and NEM operation

Our study found that Snowy 2.0 would provide substantial market benefits to the NEM and economic benefits to individual retailers through the following:

- *dispatchable capacity:* The scheme provides capacity to maintain supply reliability, reduces spot price volatility and provides for contract sales to retailers that mitigate the risk associated with intermittent (renewable) generation (referred to as 'firming')
- *storage size:* The scheme's substantial size allows Snowy 2.0 to sell 'cap'[4] contracts within normal risk limits
- *location:* The scheme's location allows capacity to be supplied directly to NSW and Victoria and to a lesser extent to South Australia. The size of the interconnector with Queensland limits sales to Queensland
- *fast response:* Snowy 2.0 could be operated in a manner that provides the fast response required under '5-minute pricing'

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3 5-minute pricing refers to the energy market settling on a 5-minute basis rather than the current 30-minute basis (the 30-minute price is the average of six 5-minute prices). The impact of this will be to require generators to be fast enough to respond to the 5-minute prices, whereas previously response was required only within the 30-minute period.

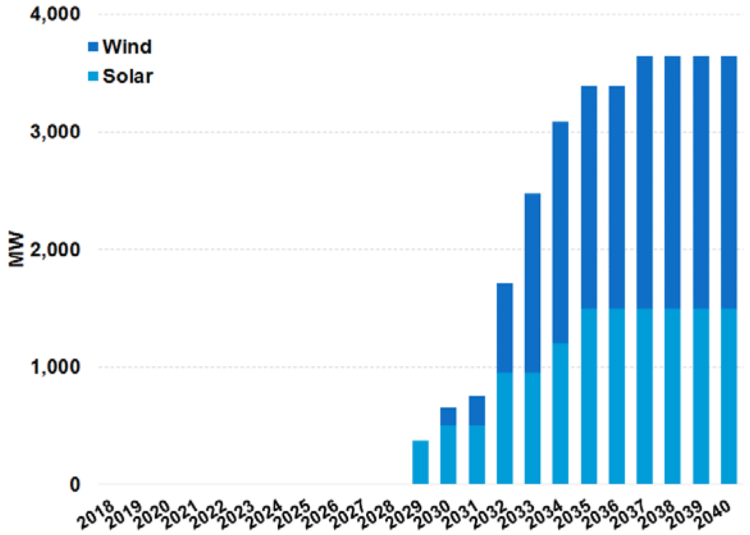
4 Cap contracts provide hedges against high spot prices, which are typically prices greater than $300/MWh; that is, they 'cap' very high prices to the buyer of the contract.

- *inertia:* The new synchronous generators would increase the inertia of the NEM (which is expected to become increasingly valuable as coal-fired generators are closed).

We then investigated the outlook of the NEM on the assumption that Snowy 2.0 is developed and enters service by 1 July 2025 using the same LRET+VRET and LT Commitment development scenarios. For the scenarios considered, we found the Snowy 2.0 pumped storage system to have a profound influence on NEM outcomes. These scenario outcomes were:

- a substantial quantity of additional renewable generation entered based on economics in the LRET+VRET renewable scenario (having renewable generation entry above given by the LRET and VRET), but no additional renewable generation entered based on economics in the LT Commitment scenario. This is consistent with the economics of renewable generation decreasing as additional renewable generation is developed without storage
- renewable generation offloading remains with Snowy 2.0, this being mainly due to the additional renewable generation that enters the system (in the LRET+VRET scenario).

Figure ES4: Additional renewable generation development with Snowy 2.0, LRET+VRET scenario (MW)



Source: Marsden Jacob, 2017.

- the profile of coal-fired generator operation is more stable, lowering costs and stress on those generators. This could potentially extend the operating lives of those generators (although that was not assumed)
- a lower number of batteries and OCGT plants were installed due to the dispatchable capacity provided by Snowy 2.0
- gas use is reduced due to energy arbitrage in the spot market[5] and the increased level of renewable generation
- additional cap contracts, suitable under 5-minute pricing, become available to retailers. This improves hedging, lowers risk, improves competition, and reduces costs to NEM consumers.

5 This refers to pumping using low-cost generation (renewable and coal-fired generation) and generating to reduce high-cost generation (gas-fired and high-price coal-fired generation).

The Impact of Snowy 2.0

Market Benefits and Snowy 2.0 Revenues

Snowy 2.0 would provide market benefits that reflect a reduction in capital and operating costs (including fuel costs) that would otherwise be needed for the production of wholesale electricity and maintaining supply reliability in the NEM.

The costs that would change due to Snowy 2.0's operation are:

- capital and fixed costs - new dispatchable generation and new renewable generation construction costs and fixed operations and maintenance costs
- operations costs - fuel (coal and gas) costs and variable operations and maintenance costs.

The change in these costs that would occur due to Snowy 2.0 are influenced by factors such as demand growth, closures of existing power stations, gas and coal costs, the flexibility of thermal power stations to respond to rapidly changing renewable generation output, the provision of ancillary services, and the frequency of conditions such as drought.

In addition to the market benefits associated with having Snowy 2.0 operate in the NEM, Snowy 2.0 infrastructure would make possible the development of additional pumped storage at Snowy (Snowy 3.0) should that be needed in the future (due to changing market conditions or commercial opportunities). This 'option' provides a substantial market benefit, depending on the probability that Snowy 3.0 would be developed. The market benefit of this option is the market benefits as defined less development costs of the additional pumped storage

Modelling was undertaken to quantify the market benefit that Snowy 2.0 would provide and the impact of Snowy 2.0 would have on energy costs to consumers. This involved modelling the two scenarios of mandated renewable generation entry (LRET+VRET and LT Commitment scenarios) with and without Snowy 2.0. For each scenario, the difference between the with and without Snowy 2.0 cases represented the market benefits from developing Snowy 2.0.

Observations from the modelling of market benefits are as follows:

- the market benefits are substantial and reflects the 2,000 MW of firm dispatchable capacity provided and the utilisation of renewable and coal generation at times of low value
- the higher market benefits in the LT Commitment scenario reflect the greater utilisation of Snowy 2.0 in shifting energy as required under the scenario of higher renewable generation
- the spread of market benefits arises from the uncertainty in the future development of batteries. Future battery development will be primarily determined by the economics of providing fast response (under 5 minute pricing) and the firming of intermittent generation
- Snowy 2.0 would have the capacity and storage size to address the full needs of the NEM until the early 2030's. Those needs include smoothing intermittent generation profiles, providing dispatchable capacity to address the foreshadowed coal-fired power station closures in NSW and Victoria, and increasing the availability of hedging contracts necessary for retailers' risk management and retail competition
- beyond the early 2030's, when higher levels of emissions abatement may be necessary, renewable generation costs are projected to be lower and additional coal generation is closed, additional large-scale storage will be required. The development of Snowy 2.0 provides for further pumped storage development and the option to quickly address additional coal-fired plant closures that may occur due to the working condition and operating costs of generators (associated with age).

Energy price reduction to NEM consumers

The modelling of Snowy 2.0 operation provided the impact on spot price outcomes in the each of the NEM states for the first 10 years. This modelling showed the following:

- annual average energy spot prices reductions were variable and depended on the level of renewable generation development and the flow-on effect to the economics of new and existing dispatchable generation
- the LT commitment scenario had an average reduction in NSW spot energy prices of $6.9/MWh (10.2% of average spot prices) while the LRET+VRET scenario had an average reduction of $1.2/MWh (1.6% of average spot prices). Based on the average of these scenarios the expected average NSW spot price reduction was $4.1/MWh, or about 5.7% of NSW spot energy prices
- The reduction in Victorian spot energy prices was lower and averaged 3.2%
- the modelling also showed that Snowy 2.0 would result in a reduction in spot price volatility. This would mean lower risk premiums for wholesale energy purchase costs, and energy prices reductions in excess that that shown through the spot market.

In summary, the modelling showed that the pumped storage capability provided by Snowy 2.0 would provide increasing market benefits and associated energy price reductions to NEM consumers as the level of intermittent generation increases.

PART A: Introduction and background

1. Introduction

This report presents the findings of an independent study by Marsden Jacob Associates (Marsden Jacob) of the effects of an increasing penetration of intermittent electricity generation on the operation of the National Electricity Market (NEM), the changing nature of the NEM in providing reliable electricity supply, and the impact the proposed Snowy 2.0 scheme would have to the NEM.

Snowy 2.0 is a pumped hydro storage scheme, to be located in the Snowy Mountains. It would have 2,000 MW of capacity and enough storage to operate continuously for seven days when the storage is full. Cycle losses (the energy required to pump minus the energy returned from generation) would be 24%.

This report has been written for a wide readership, including people not familiar with the technical issues associated with the NEM and electricity power systems.

1.1 Motivations for this report

The manner the NEM will operate and the economics of existing and new generators under an increasing penetration of intermittent generation are complex.

While much has been written about electricity supply in the NEM as it transitions to increasing levels of renewable generation, there is little literature that explains in a fundamental way how the NEM is changing and what this will mean to generators and retailers operating in the NEM or intending to operate.

This report is intended to address this and to consider how Snowy 2.0 would help to address emerging supply issues.

Key matters presented and explained include:

- the level of intermittent generation that will develop because of government energy policy, economics, consumer preferences, or any combination of those factors
- the type of interaction that intermittent generation will have with dispatchable generation and how that will affect the economics and reliability of generation
- the economics of intermittent generation, dispatchable generation and storage technologies
- the market benefits[6] that Snowy 2.0 would provide (to the NEM) and impact of Snowy 2.0 to consumers costs.

6 Defined later in the report.

1.2 Structure and approach of this report

This report has been structured into four sections that address in turn:

- power systems and how they operate. In includes the technologies available for generation and energy storage and their costs
- the NEM and how this operates financially, and the reforms that will impact this
- the outlook for the NEM in terms of coal generator closures, demand growth and the amount of renewable generation that will be developed. Also presented is the impact renewable generation development has on dispatchable generation
- how the NEM would develop on the assumption Snowy 2.0 is not developed and on the assumption Snowy 2.0 is developed. In includes a description of Snowy 2.0 and the way it would operate. From these two scenarios the impact Snowy 2.0 would have is determined.

1.3 Notes to this report

All dollars presented in this report are real 1 July 2017 Australian dollars, unless otherwise specified.

Market refers in the NEM.

The terms *intermittent generation* and *renewable generation* are used interchangeably throughout the report.

The terms *dispatchable generation* and *controllable generation* are also used interchangeably throughout the report.

Snowy 2.0 refers to the proposed pumped hydro storage scheme in the Snowy Mountains. *Snowy* refers to the existing Snowy hydro-electric scheme and does not include Snowy 2.0.

Generator (and retailer) economics refers to generator (retailer) revenues compared to generator (retailer) costs accounting for risk.

Market benefits refers to the definition of market benefits defined by the Australian Energy Regulator in the Regulatory Investment test for Transmission (RIT-T).

2. The NEM, the changed development paradigm and the rationale for Snowy 2.0

This chapter describes how Australia's generation mix evolved and the history of renewable generation ('renewables'; chiefly wind and solar generation) and CO2 abatement policy, both of which have led to the current position of the NEM.

The implications of technical and policy developments might not have been fully understood by policymakers, operators and market participants, particularly the 'margin' or flexibility needed for the successful integration of intermittent generation.

The chapter shows the following:

- Apart from South Australia, the NEM states do not yet have a significant amount of renewable generation, and operation is influenced by other factors such as increasingly volatile weather and ageing coal plant.
- The substantial amount of renewable generation in South Australia has required that additional dispatchable capacity be added, and that is occurring in 2017.
- Ageing coal-fired plant (only one-third of coal-fired plant in the NEM is less than 30 years old), the reducing costs of renewable generation and renewables' environmental advantages are the key factors determining the future development of the NEM.
- The trend towards increasing intermittent generation and retiring coal-fired plant signals that both new dispatchable capacity and substantial energy storage are required.

By providing substantial capacity and energy-shifting capability, Snowy 2.0 would be able to address the likely deficit of dispatchable generation in the NEM in order to maintain a secure and reliable power supply, and to help reduce the price volatility expected to be associated with high levels of intermittent energy.

2.1 Introduction

The ability of the NEM to satisfy the National Electricity Objective[7] has been scrutinised over the past year because of significant increases in electricity prices and problems with supply reliability over the 2016–17 summer. Both have been attributed to significant changes in the NEM, including the increasing penetration of wind and solar generation (both distributed and large-scale), the tightening of the gas market, which is associated with the commencement of the liquefied natural gas (LNG) plants in Queensland, and the closure of

7 'To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the NEM.'

coal-fired generators (most notably the 1,600 MW Hazelwood Power Station in March 2017).

On the policy front, the Australian Government commissioned the Independent Review into the Future Security of the National Electricity Market (the Finkel review), which reported in June 2017,[8] to develop recommendations that would enable Australia to meet its greenhouse gas emissions reduction obligations while maintaining supply reliability and security and putting downward pressure on electricity prices. The Finkel report supported the general position that economics and climate change policies would continue to drive further development of intermittent renewable generation in the NEM, particularly wind and solar. In addition, the review reported that increased dependence on intermittent generation is creating a major issue for the NEM's ability to provide affordable and reliable electricity supply in the long term.

This chapter describes the context of the current energy 'crisis' through a review of developments in the NEM that have contributed to the current situation. It then considers the rationale for Snowy 2.0 in this context and the basis for moving ahead with the scheme.

2.2 Contextual history

The current state of the NEM and the development issues confronting the market are a reflection of the historical factors that provided for the current mix of generation, the energy policy response to climate change, technology developments (which have accelerated in response to environmental issues), electricity market reform, industry consolidation that has occurred under that reform, and developments in supporting commodities, such as gas.

Background to the existing mix of dispatchable generation

The history of the eastern Australian electricity system (which now operates as the NEM) is one of using coal reserves to fuel coal-fired power stations, gas generation from the early 1980s in response to an increasing need for intermediate generation, and hydro-electric generation (most significantly from Snowy Hydro) to provide capacity to supply high demand.

On a state-by-state basis, development occurred as follows.

Queensland

- Coal-fired generation was developed based on the significant coal reserves in Queensland.
- The Queensland Gas Scheme was introduced in 2005 to support the development of the state's coal-seam gas industry. The scheme required wholesale electricity suppliers to procure 13% of energy from gas generation, and new gas generators were developed to use the available low-cost gas.

New South Wales

- Black coal was used almost exclusively in NSW, supplemented by hydropower generation from Snowy Hydro. The NSW black coal power stations operated spare plant so that that they could reduce or increase output as needed to match NSW demand. These generators were and are more flexible than the Victorian brown coal power stations.

Victoria

- The huge brown coal reserves in the Latrobe Valley in Victoria provided very low-cost coal, so generation development in Victoria was based on that coal. The power stations had high capital costs and were suited

8 A Finkel, *Independent Review into the Future Security of the National Electricity Market*, Commonwealth of Australia, 9 June 2017, www.environment.gov.au/energy/national-electricity-market-review [11 September 2017].

to continuous base-load operation. They were used to provide subsidised electricity to smelters in Victoria.
- Low-cost gas was available from the Gippsland Basin and was used for gas-fired generation to support base-load brown coal generation.
- Snowy Hydro provided peak demand capacity.
- The age of the plant and potential refurbishment costs resulted in Hazelwood Power Station (1,600 MW) closing in 2017.

South Australia

- South Australia is the state with the smallest electricity demand.
- Interconnection with Victoria provided capacity required on high-demand days. The tendency for very hot, high-demand days to occur at the same time in Victoria and South Australia meant that South Australia also relied on peak capacity from Snowy Hydro to supply that demand.
- South Australia does not have significant coal reserves. Coal-fired generation was developed in the 1980s (Northern Power Station and Playford Power Station) using coal from the remote Leigh Creek coalmine. Extensions to the Leigh Creek mine were needed to maintain Northern Power Station beyond 2016, and the very high costs of that work were the main factor causing the power station's closure in that year.[9]
- From the early 2000s, gas from the Otway Basin was used for gas generation in South Australia.
- After supply blackouts in the summer of 2016–17, the South Australian Government instigated a number of actions, which are listed in Table 1.

Table 1: Initiatives by the South Australian Government in 2017

Initiative	Impact
New open-cycle gas turbine (OCGT) generator (say, 250 MW) may operate only at very high spot prices (say, >$5,000, but not clear)	May also be used to ensure that the station is economic and to moderate spot prices. Would limit private-sector generation. May reduce South Australian spot prices.
100 MW battery storage installed by 1 January 2018 (expect 4 hours continuous operation). Likely to arbitrage spot prices.	Would be available for high-demand events (can charge with short notice). Would moderate South Australian spot prices.
New powers for South Australian minister to direct generators (overriding AEMO powers).	The AEMO would need to direct other plant, at potentially higher cost. It is unclear how this would work.
Gas reserves funding (payment to landholders for producing wells).	South Australian gas reserves near Moomba could provide for additional gas development, although the potential impact of this is assessed to be small.
Retailers to source 36% of their generation load from South Australia.	Suitable generation must be made available. No perceived impact.

AEMO = Australian Energy Market Operator.

Source: Marsden Jacob, 2017.

Tasmania

- Tasmania had very substantial hydro-electric resources to support its moderate electricity demand. The abundance of low-cost hydropower supplied a substantial level of industrial demand.
- There was a substantial risk of hydro-generation being short in years of drought, and oil-fired generation (to be used only when dam water levels dropped below set levels) was added. In 2004, the Basslink

9 Coal from deeper coal seams was needed.

interconnector was constructed to provide protection during drought and to allow Tasmanian hydro-generation to arbitrage[10] Victorian spot prices.

Transmission between the states

Interconnection between the states occurred for various reasons. The development of the Snowy hydro scheme, of which ownership was shared between Victoria, NSW and the Australian Capital Territory (ACT), resulted in Victoria and NSW becoming connected. South Australia connected to Victoria when 500 kV lines were extended from the Latrobe Valley to the Portland smelter near the Victoria – South Australia border. NSW connected with Queensland as part of the entry of Queensland into the NEM.

Since those initial interconnector developments, there have been a number of interconnector upgrades based on improved economics for the NEM.

The interconnections have provided substantial value in sharing generation reserves between the states and in better utilising low-cost generation.

Environmental policy and the development of renewable generation

Climate change policy directed at changing the generation mix in the NEM to use lower emissions-intensity technologies has presented challenges since the NEM began. The development of climate change policies applied to the NEM can be summarised as follows.

In 2000, the Howard Coalition government introduced the Mandatory Renewable Energy Target. This required large electricity purchasers to source an additional 2% or 9,500 GWh of their electricity from renewable sources by 2010. Under the scheme, each 1 MW of renewable energy produced created a tradeable renewable energy certificate that could be purchased by retailers to meet their obligations under the scheme.

Due to the modest ambitions of the Mandatory Renewable Energy Target, the Victorian government introduced the Victorian Renewable Energy Target (VRET) scheme. Other states considered similar action. The VRET was abandoned when the Australian Government began the Large-scale Renewable Energy Target (LRET) scheme, which had a higher target, in 2011.

The Rudd Labour government signed the Kyoto Protocol in 2008.

In 2009, the Rudd government increased the RET to 45,000 GWh by 2020 (intended to represent 20% renewable generation supply by 2020).[11] This scheme included both large-scale renewable generators and small (behind-the-meter) technologies. Households and businesses that installed rooftop photovoltaic (PV) systems received, up front, the total future value of renewable energy certificates created by the systems. This was a major incentive for investment by households and businesses.

This scheme resulted in a vast oversupply of renewable energy certificates associated with the small-scale technologies and the associated certificate multipliers. The solution in 2011 was to split the RET into the LRET, with a target of 41,000 GWh by 2020, and the Small-scale Renewable Energy Scheme (SRES), with a nominal target of 4,000 GWh per year and an annual target established each year based on the projected installation of qualifying energy sources.

In 2013, the Abbott Coalition government reviewed the LRET and SRES and published the findings and

10 ‘Arbitrage’ (used here as a verb) is the simultaneous purchase or sale of items in different markets in order to profit from unequal prices in those markets.

11 The outlook was an electricity demand of 300,000 GWh by 2020, 20% of which is 60,000 GWh, and 15,000 GWh of existing renewable generation. This has the RET providing 45,000 GWh.

recommendations of the review in the Warburton report.[12] The main finding, which in essence was to cease further subsidisation of large-scale renewable generation, resulted in investment in renewables virtually ceasing over the period from 2013 to 2015.

From about 2010, increased rooftop PV and energy efficiency were resulting in wholesale electricity demand reductions, and a consequential outlook that the legislated LRET would correspond to over 25% of electricity being produced by renewables by 2020.

In July 2015, based on a consensus of both the major political parties, the LRET was reduced to 33,000 GWh by 2020. This more closely represented 20% of electricity being supplied by renewables by that year.

Since the introduction of the 33,000 GWh target and the political consensus that this target should remain, there has been a surge in large-scale renewable generation development.

During this period, renewable technology costs (in particular, for solar technology) have decline substantially, and by more than projected. This has reduced the hurdle for development and is a likely factor contributing to the large number of projects being considered for development.

The rate of rooftop PV installation has increased from 36.7MW in January 2009 to approximately 6,500 MW in September 2017 since the introduction of the RET13.

In 2016, Australia signed the Paris Agreement, committing Australia to reduce its CO_2 emissions by 26%–28% from the 2005 level by 2030.

On 10 May 2016, the Alinta-owned Northern Power Station (500 MW, coal-fired) was closed in South Australia.

The Victorian, Queensland and South Australian governments have taken the position that renewable generation developments should continue after 2020. The LRET does not support such developments, as the 2020 target of 33,000 GWh does not increase after that year. In 2016, the Victorian, Queensland and South Australian governments announced state-based renewable generation targets, but at the time of writing only Victoria has legislated a new target (once again called the Victorian Renewable Energy Target, or VRET). The targets are:

- *Queensland:* 50% renewables by 2030, plus increased rooftop PV targets
- *Victoria:* 25% renewables by 2020; 40% renewables by 2025
- *South Australia:* 50% renewables by 2025, which will be met through the LRET.

The increasing amount of renewable generation has given rise to concerns about the future security and reliability of electricity supply in the NEM. Increasing electricity (and gas) prices and the events in South Australia over the 2016–17 summer led the current Prime Minister, Malcolm Turnbull, to suggest that Australia is in the midst of an energy 'crisis',[14] and that the NEM is 'broken'.[15]

The large amount of large-scale renewable generation in South Australia has resulted in supply reliability

12 Warburton Review, Renewable Energy Target Scheme: report of the Expert Panel, 2014, http://climatechangeauthority.gov.au/reviews/2014-renewable-energy-target-review/report. [12 September 2017].

13 Australian Photovoltaic Institute, 2017, http://pv-map.apvi.org.au/analyses. [20 November 2017].

14 N O'Malley, 'Malcolm Turnbull warns Australia is in an "energy crisis"', *Sydney Morning Herald*, 9 March 2017, www.smh.com.au/federal-politics/political-news/malcolm-turnbull-warns-australia-is-in-an-energy-crisis-20170308-guu1bb.html [12 September 2017].

15 M Warren, *Is the National* Electricity Market 'broken'?, Australian Energy Council, 13 April 2017, www.energycouncil.com.au/analysis/is-the-national-electricity-market-broken/ [12 September 2017].

issues in that state and a view that future policies need to address the ramifications of increasing penetration of renewable generation across the NEM.[16]

In November 2016, Engie announced that Hazelwood Power Station would close at the end of March 2017. In November 2016, the Australian Energy Market Operator (AEMO) stated that the 'AEMO expects that there will be sufficient capacity available to continue to operate the NEM reliably following the retirement of the Hazelwood Power Station next year.'[17]

In late 2016, in response to the 'electricity crisis', the Turnbull Coalition government commissioned the Chief Scientist, Alan Finkel, to report on this matter and make recommendations. Among 50 recommendations, Finkel suggested the adoption of a Clean Energy Target but did not specify what an appropriate target might be.

Wholesale energy prices in the NEM tripled in 2017. Marsden Jacob attributes this to increasing gas costs, the closure of Hazelwood Power Station (spot prices increased prior to the closure) and bidding profiles by generators in the NEM.

Spot electricity prices declined from high levels to moderate levels in late 2016 without any additional generation, demonstrating the ability of large portfolio generators to influence spot prices.

In March 2017, Prime Minister Turnbull announced the development of Snowy 2.0.

The South Australian and Victorian governments held auctions for storage to be installed before the summer of 2017–18. South Australia is also installing 250 MW of small open-cycle gas turbine (OCGT) capacity, to be available by the end of 2017. In justifying the investment in battery storage in South Australia, the state government indicated that the batteries would provide energy while the OCGT plant was starting up and synchronising to the grid.

With regard to national RET scheme, as of September 2017:

- the LRET had resulted in about 6000 MW of investment in large-scale renewable generation. Currently there are about 4,500 MW of renewable projects that are 'committed' and 'probable capacity'[18]
- the SRES has resulted in 5,426MW of behind-the-meter capacity and an outlook for the installation of 19,500MW by 2036-37 for solar rooftop PV19.

In August 2017, the Victorian Government announced that it would be legislating for the establishment of the VRET scheme. Queensland has also indicated that it wants to establish a renewable target for the state, but the target has not been legislated at the time of writing.

On 17 October 2017, the Australian Government ruled out the Clean Energy Target proposed by the Finkel review, opting instead to create a more 'neutral' and 'affordable' plan called the National Energy Guarantee.[20] The National Energy Guarantee is intended to address electricity supply reliability in the NEM and Australia's emissions obligations. The essence of the scheme is that retailers would be responsible for contracting

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16 The predominance of quality wind sites in South Australia meant that most early wind generation developments occurred in that state. Potential problems, such as transmission issues and increasing challenges of frequency control, were recognised early. The decreasing economics of wind generation in South Australia due to such generation receiving a discount to the spot price was also recognised.

17 AEMO, *Market insight report*, November 2016.

18 Large-scale Renewable Energy Market data, *Clean Energy Regulator,* 20 November 2017.

19 Clean Energy Australia Report, *Clean Energy Council, 2016,* [20 November 2017].

20 'Clean Energy Target dumped by Coalition in favour of Malcolm Turnbull's new plan', *ABC News*, 17 October 2017, www.abc.net.au/news/2017-10-17/clean-energy-target-dumped-by-coalition-in-favour/9059630.

generation that meets reliability and emissions requirements.

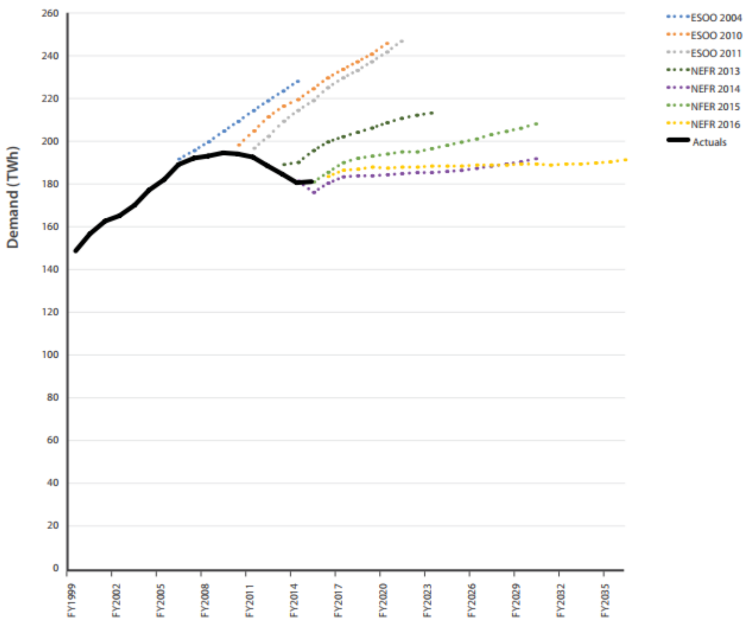
The NEM started to change after 2010

Until about 2010, the amount of renewable generation and rooftop PV did not have a significant influence on the NEM. Around 2010, the characteristics of the NEM started to change.

Growth in scheduled demand stopped due to the increasing level of rooftop PV, greater energy efficiency and lower growth in Australia's gross domestic product. However, electricity demand forecasts continued to project demand growth until 2015.

Figure 1 shows the NEM's annual energy demand and the projections of demand made by the AEMO and its predecessor, the National Electricity Market Management Company (NEMMCO). It took about four years to recognise that the level of demand growth experienced over the period from 1999 to 2009 would not apply in the future. This static demand outlook, combined with increased intermittent generation, changed the economics of the NEM.

Figure 1: Historical annual NEM demand and AEMO projections (TWh)

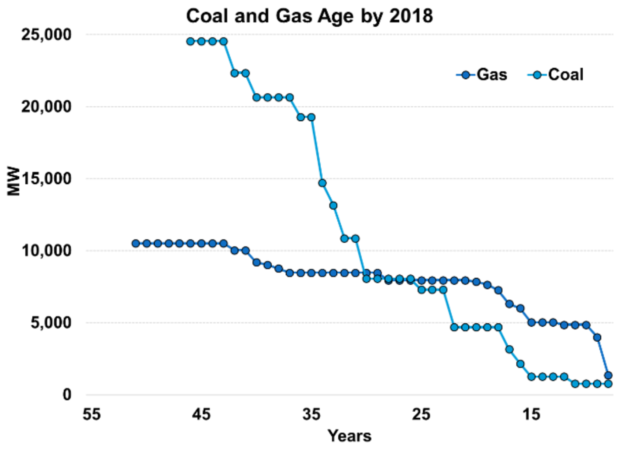


Source: A Finkel, *Independent Review into the Future Security of the National Electricity Market*, 9 June 2017, Commonwealth of Australia, www.environment.gov.au/energy/national-electricity-market-review [11 September 2017].

Dispatchable generation age profile

The result of energy policy and flat demand growth has been the absence of dispatchable generation capacity and a coal-fired generator fleet that is mostly over 30 years of age. The age distribution of coal- and gas-fired plant in the NEM is shown in Figure 2.

Figure 2: Age distribution of coal and gas generation in the NEM



The graph shows the total capacity (MW) of coal- and gas-fired generation that has an age less than that shown on the x-axis.

For example, there is only about 7,500 MW of coal-fired generation with an age less than 30 years.

Source: Marsden Jacob, 2017.

The ageing of the coal-fired generator fleet has been evident in the number of generators that have closed in recent years (Figure 3).

Figure 3: Closures of coal-fired power stations, 2016, and future closures

Source: South Australian Government, *Our energy plan*, no date, http://ourenergyplan.sa.gov.au/assets/our-energy-plan-sa-web.pdf [11 August 2017].

2.3 The current NEM: average week generation mix

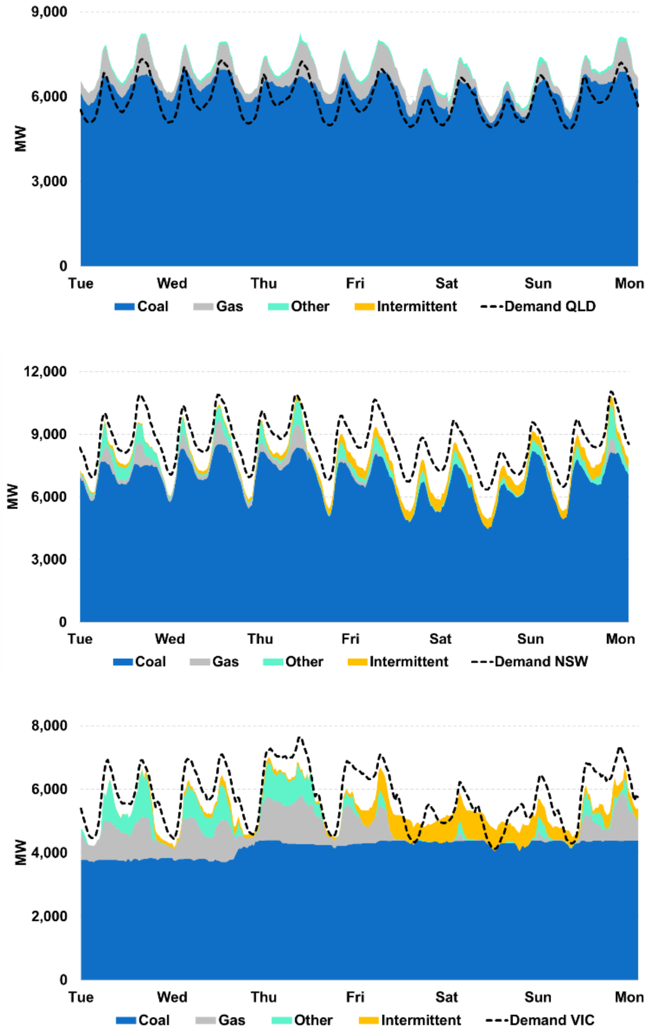
The historical influences described above have led to the generation mix of the NEM as it is today. This is the starting point for projecting what will occur in the future and the value that assets such as Snowy 2.0 would deliver.

A convenient way to illustrate the current operation of the NEM is to show the level of coal-fired, gas-fired, intermittent and other generation for a typical week in 2017. Figure 4 shows the profile of demand and generation on a state-by-state and a total NEM basis for the week commencing on 1 August 2017, which was a week of 'normal' operation.

Pertinent observations are as follows:

- Renewable generation is not significant in regions other than South Australia. South Australia has a very high level of renewable generation, which is very volatile.
- Queensland has a flatter demand profile. Generation is largely from coal, but gas-fired generation operates for most hours.
- NSW coal-fired generation varies considerably in response to demand changes (that is, it provides an amount of 'load following').
- Victorian coal-fired generation operates with little variation (there was more variation before the closure of Hazelwood Power Station). Gas-fired and hydropower generation (including from the Snowy) act as intermediate and peaking generation.
- On a total NEM basis, the amount of renewable generation is currently modest.

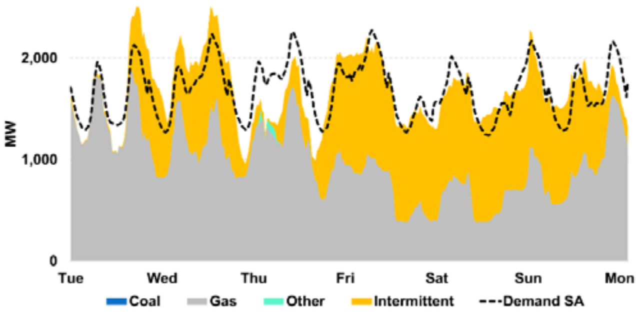
Figure 4: Generation mix, week commencing Tuesday 1 August 2017 (MW)



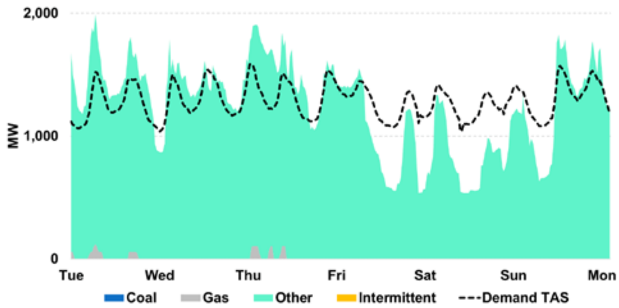
Queensland

New South Wales

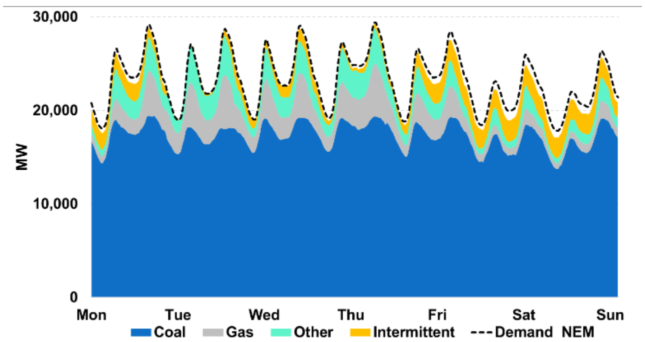
Victoria



South Australia



Tasmania

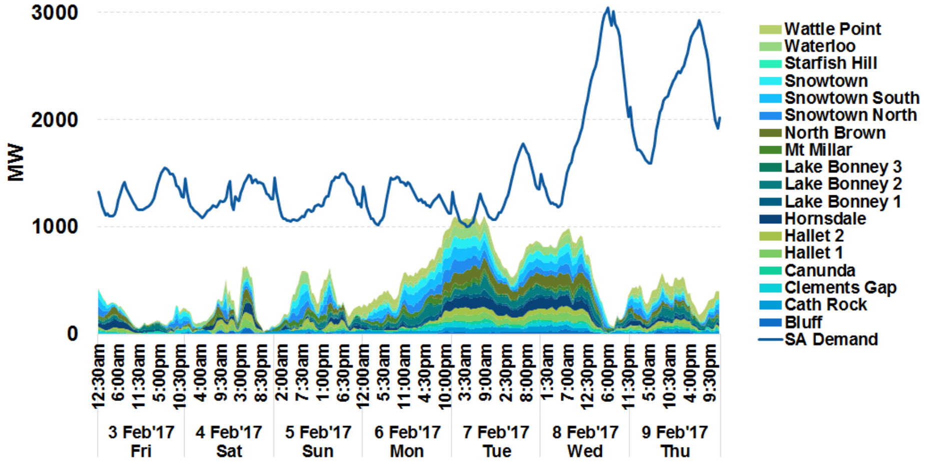


Total NEM

Source: AEMO published data; Marsden Jacob, 2017.

While the power system operates well during typical weeks, the variability of intermittent generation and high weather-related demands can cause conditions to change very quickly. This is illustrated in Figure 5, which shows South Australian intermittent wind generation and demand for the week commencing on 3 February 2017. The gap between demand and wind generation went from zero on 7 February to 3,000 MW on 8 February.

Figure 5: South Australian intermittent generation and demand, week commencing 3 February 2017 (MW)



Source: AEMO data, NEO Data Viewer, Marsden Jacob, 2017.

Higher levels of intermittent generation because of either environmental policy or economics (due to the falling costs of solar and wind generation) will increasingly influence the operation of the NEM and consumer prices.

2.4 The rationale for Snowy 2.0

The evolution of the NEM is highly uncertain, and changes in technology, costs, policy and customer preferences are occurring at a rapid rate.

As energy generation needs to balance with customer demand in real time, the integration of intermittent generation will require increased peaking generation and energy storage solutions to provide a sufficiently fast response capacity and to 'time shift' non-dispatchable renewable generation to those periods when it is needed. The requirements for the NEM include storage that can provide energy for consecutive days.

The proposed Snowy 2.0 scheme consists of the development of 2,000 MW of pumped-hydro storage that can supply energy over seven consecutive days without the need to pump water. It is intended to address many of the challenges currently facing the NEM, which include firming intermittent generation, supporting the economics of existing coal-fired generation, and enhancing competition in the electricity value chain.

Critically, the development of Snowy 2.0 supports the National Electricity Objective and the findings of the Finkel review that relate to the generation and supply of energy in the NEM.

Table 2 lists the key outcomes identified in the Finkel report and the outcomes that Snowy 2.0 would support. On this basis, Marsden Jacob was asked to consider the economics of Snowy 2.0.

Table 2: Finkel report key outcomes and Snowy 2.0

Key outcomes		Snowy 2.0
Increased security	Generator security obligations	Reduces regulatory need
	System security obligations	Improves security
	Strengthened risk management	Additional contract supply Improved risk management
Future reliability	Generator reliability obligation	Reduces need
	Incentives for new generation	Improves economics of intermittent generation
	Existing generators do not close prematurely	Allows base-load generators to operate more continuously.
	Investor confidence	Greater confidence in orderly system and market operation
Reward consumers	Rewards for managing demand	–
	Avoiding new network costs	–
	Lowest cost generation	Increased economies and lower risk premiums
	Price inquiry and better information	More stable prices
Lower emissions	International commitments	Improving the economics of renewable generation
	Electricity sector: continuous reduction	Orderly path for reduced emissions

Source: Marsden Jacob, 2017.

PART B: Fundamentals of power system economics

This section presents material that supports the discussion and analysis of how the NEM will develop under an increasing penetration of renewable generation and the impact that Snowy 2.0 would have on that development and operation of the NEM.

The matters considered fall under three main headings:

- *Power system economics21:* a concise review of the economics of generation in a power system.
- *Generation technologies and outlook:* a review of the generation technologies that have traditionally been used and of those being developed under renewable energy policy.
- *Storage technologies:* a review of available and emerging technologies.

This part of the report (excluding Chapter 5 on Snowy 2.0) can be skipped by readers familiar with these matters.

21 Power system economics is common terminology for the operating and development costs of generation and transmission, and the optimisation of these costs.

3. Generation supply fundamentals

This report assumes some knowledge of generator types, their cost structures and the different roles that generators play in supplying electricity. These concepts and definitions underpin the analysis of the impact that electricity storage options (such as Snowy 2.0) would provide to a power system (such as the NEM).

Particular matters covered in this chapter include:

- the key elements of the supply chain involved in supplying electricity, which are collectively referred to as a *power system*
- the types of generators that operate in the generation system and the cost structures of those generators
- the economics[22] and role of each generator type in ensuring reliable and secure supply of electricity to meet consumer demand
- the ways that renewable generation that is *intermittent* affects the way generators operate and the associated risks.

3.1 Power systems

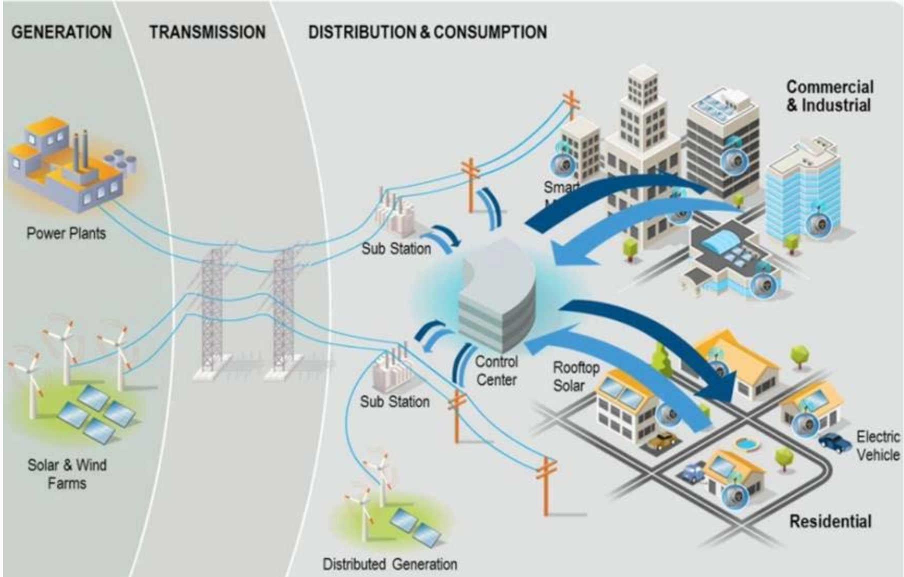
Power systems are electricity infrastructure, including power stations, transmission systems and distribution systems, and customer loads:

- Power stations generate electricity. They usually comprise a number of individual generator units. In Australia, most power stations use fossil fuels such as coal, gas or oil, or distillates derived from those commodities, for their energy source. Others use water to generate hydropower. These are the fuel sources used in the power systems that make up the NEM.
- From the power station, electricity is transported to cities and towns by high-voltage transmission lines, and then to electricity users (consumers) by low-voltage distribution lines (poles and wires). High-voltage transmission lines can transport more power and with lower energy losses (electricity dissipated in transport due to heating of the wires) than in distribution systems.
- Electricity users include homes, commercial buildings, farms, factories and large industrial users, such as aluminium smelters. The amount of electricity that is used is referred to as the (customer) load or demand.

Figure 6 is a diagram of a power system.

22 Economics refers to the costs and revenue of generators.

Figure 6: Key elements of a power system (excluding storage)



Source: Trilliant, *Open smart grid*, no date, https://trilliantinc.com/home/smart-grid/ [8 November 2017].

For power systems to work, they have to be properly operated. This requires that all the technical factors (such as voltage) are operating within limits and all necessary activities are properly coordinated. Key activities in operating a power system include starting and shutting down generators and controlling how much electricity is produced by each one:

- *Starting and shutting down generator units:* This is called *committing* and *de-committing* generator units. The process of committing a large coal-fired generator begins with the burning of coal until operating temperatures are reached, using the heat to create steam, which powers turbines to produce electricity, and then physically connecting the generator to the transmission system by closing large switches (called circuit-breakers). Depending on the size and fuel of the generator unit, the entire process can take up to about 12 hours.
- *Determining the amount of electricity each generator will produce:* This is referred to as *generator dispatch.* The amount of generation from all generator units is required to equal total customer demand plus power losses (from transmission and distribution lines) through time. For economic reasons, it has been normal practice to dispatch (or use) committed generators in order of increasing fuel cost (that is, low fuel cost generators are used first). The costs of inefficient dispatch can be substantial, but it is necessary in certain circumstances due to power flow limits on transmission lines (referred to as 'network constraints') or other factors.

Power system management also requires proper planning to ensure that customers will be economically and reliably supplied in the future (accounting for increasing demand and ageing assets). The bodies that do this include the following:

- *Power system operators:* These organisations (or departments within utilities) plan, monitor and coordinate the operation of generators and transmission lines. These bodies are also commonly referred to as the *system operators* (for example, the AEMO in the NEM**).**
- *Planning organisations:* These organisations forecast the future level of electricity demand and determine what new transmission lines and generators are needed. Electricity markets place the planning of new generators in the hands of the market.

3.2 Generators

A variety of generator types are used in power systems, each with different operating characteristics. The types of generator that are developed in a power system reflect the fuel resources available, associated costs, and the nature of the demand to be supplied.

Generator and storage types

The main generator types operating in Australia are as follows:

- *Coal-fired* generators burn coal in boilers to produce steam to run through steam turbines.
- *Open-cycle gas turbine* (OCGT) generators use gas ignited in combustion chambers to drive turbines in the same way as in jet engines. Most OCGT units in Australia have been heavy-frame units with efficiencies of 30–32%. Increasingly, aero-derivative gas turbines with high efficiencies (around 38–40%), which are referred to as *high-efficiency gas turbines*, are being deployed in Australia.
- *Combined cycle gas turbine* (CCGT) generators employ a combination of gas turbines and thermal technology (waste heat from the gas turbines is used to create steam in a boiler).
- *Co-generation* refers to a group of technologies that operate together to produce both electricity and steam or hot water that is used in industrial processes
- *Hydro-electric* generators use water flowing from a high reservoir to a low reservoir to drive turbines.
- *Wind* generators use wind to drive turbines.
- *Solar* generators use solar radiation to produce electricity. The most common solar technology is currently PV.
- *Energy storage* technologies allow surplus generation to be stored for later use. The key characteristics of this technology are the capacity available (measured in MW), the total amount of energy that can be stored (MWh), and the energy losses involved in storing and using the stored energy (‘round-trip efficiency’). The two most common and viable technologies in the NEM are pumped hydro and battery storage technologies.

Operating flexibility

Operating flexibility refers to key operating characteristics, such as the time needed to start and shut down a generator and, once the generator is committed, how quickly it can change its level of generation output (referred to as its *ramp rate*).

Thermal efficiency

Thermal efficiency is the proportion of fuel energy that is converted to electrical energy. This is expressed through the term ‘heat rate’, which is the ratio of fuel energy used (usually in GJ) to the electrical energy produced (MWh), giving the common unit of heat rate as GJ/MWh. In the NEM, a typical black coal generator has a heat rate of about 9.5 GJ/MWh, an OCGT plant 13 GJ/MWh, and a CCGT plant 7.5 GJ/MWh.

Emissions intensity

For a generator, emissions intensity refers to the amount of carbon dioxide equivalent (CO2e) produced, expressed in tonnes per MWh of electricity output (usually referred to as ‘at gen’ output). Typical values are 0.4 tonnes/MWh for CCGT plant, 0.9 tonnes/MWh for existing NSW black coal plants, and 1.3 tonnes/MWh for existing Victorian brown coal plants.

The general characteristics of the generator and storage types are shown in Table 3.

Table 3: Summary of generator and storage characteristics

Generator	Capital cost	Operating cost	Response flexibility	Emissions intensity
Thermal coal	High	Low to medium	Slow	High
Thermal gas	Medium	Medium to high	Slow	Medium
Combined cycle gas turbine	Medium	Medium to high	Slow	Medium
Open-cycle gas turbine	Low	High to very high	Rapid	High
High-efficiency gas turbine	Medium	Medium	Rapid	Medium
Co-generator	High	Medium to high	Slow	Medium
Wind	Medium	Low	n.a.	Zero
Solar	Medium	Very low	n.a.	Zero
Pumped storage	High	Very low	Rapid	n.a.
Battery	High	Very low	Very rapid	n.a.

Source: Marsden Jacob, 2017.

Generator costs

Generator costs are usually expressed in terms of the following:

- *Construction costs* are the costs to plan and build the power station. These costs are also commonly referred to as the '*capital cost*'. The key factors here are generator type and risk. Risk is expressed through the project weighted average cost of capital (WACC). The greater the risk, the greater the required WACC.
- *Fixed operating costs* are the sum of all costs after construction that do not depend on the level of power station output. They include fixed operating labour, time-related maintenance (material and labour) and overheads (personnel, administration, insurance and so on).
- *Variable operating costs* are the sum of all costs that are incurred through running the power station and generating electricity. These costs are often referred to as the short run marginal cost (SRMC). The key determinants of the SRMC are the cost of fuel, the efficiency of the generator (for example, the heat rate of the plant), variable operating labour costs, and usage-related maintenance costs (labour and materials).

NEM generator classifications

Generators in the NEM are classified by the AEMO according to how they participate and how they are controlled in the market.

Market generators must sell electricity through the market and accept payments from the AEMO for sent-out electricity at the spot prices applicable.[23] *Non-market* generators are those whose entire electricity output is purchased by a local retailer or customer at its connection point. Non-market generators are not entitled to receive payment from the AEMO for any electricity sent out, except for any electricity sent out in accordance with a direction issued by the AEMO to a scheduled generator.[24]

Generator units dispatched by the AEMO (based on their bids) are referred to as *scheduled generators*. They comprise all generator units greater than 30 MW that can be controlled (noting that generator units less than

23 NEM arrangements are detailed in the next chapter.

24 AEMO, Generator classifications and exemptions guide, August 2014.

30 MW have the option to be scheduled).

The output of wind and solar (renewable) generators are subject to wind and sunlight, respectively, and those are not controllable. However, the AEMO has the authority to reduce the output of these generators, which are referred to a *semi-scheduled generators*.

Small generators, of less than 30 MW, have the option of not being controlled (or scheduled) by the AEMO if their physical and technical attributes make participation in the central dispatch process feasible. When they are not scheduled by the AEMO, they are referred to as *non-scheduled generators*.[25]

Generators can be classified or exempted from categories in a variety of ways.

Table 4 summarises the range of market participation statuses and control classifications, including examples of types of generators.

Table 4: Generator classifications

		Typical capability	Examples
Exempt		Less than 5 MW, all purchased by a local retailer or a customer located at the same connection point (automatic exemption)	1 MW backup diesel generator in a high-rise building
		Less than 30 MW, all purchased by a local retailer or a customer located at the same connection point and annual export less than 20 GWh (application required)	20 MW biomass-fuelled generator with limited fuel supplies
Non-scheduled	Non-market	Less than 30 MW, all purchased by a local retailer or a customer located at the same connection point	10 MW, all purchased by a customer at the same connection point
	Market	Between 5 MW and 30 MW, with some or all sent-out energy sold in the NEM	10 MW generator supplying the wholesale market
Semi-scheduled	Non-market	Intermittent output, greater than 30 MW, all purchased by a local retailer or a customer located at the same connection point	150 MW wind farm, all purchased under contract by a local retailer
	Market	Intermittent output, greater than 30 MW, with some or all sent-out energy sold in the NEM	150 MW wind farm supplying the wholesale market
Scheduled	Non-market	Greater than 30 MW, all purchased by a local retailer or a customer located at the same connection point	40 MW hydro station, all purchased under contract by a local retailer
	Market	Greater than 30 MW, with some or all sent out energy sold in the NEM	2,000 MW power station supplying the wholesale market

Source: AEMO, Generator classifications and exemptions guide, August 2014, p. 7.

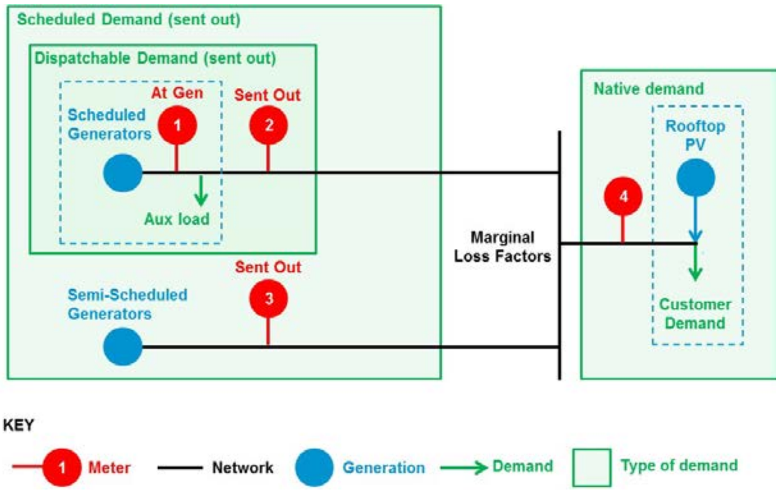
3.3 Electricity demand

Electricity demand over a certain period is measured through electricity meters, which are located at various places in the power system. Meters measure MWh at each 30-minute period. Demand is reported by the AEMO as the average MW each 30-minute period (the average of six 5-minute periods).

25 AEMO, Generator classifications and exemptions guide.

The position of the meters defines what demand is being measured. Figure 7 is a diagrammatic explanation of a power system and the meters used to measure the energy flows.

Figure 7: Illustration of scheduled demand and dispatchable demand



Source: Marsden Jacob, 2017.

We note the following:

- *Scheduled demand—sent out* is the summation of all meters at the 'gates' of scheduled and semi-scheduled power stations (meter no. 2 in Figure 7). This demand includes energy used by customers and energy losses from the distribution and transmission systems. Embedded generation, such as rooftop PV, acts to reduce scheduled demand.
- *Scheduled demand—at generator* is the summation of all meters at the generator terminals (meter no. 1) and semi-scheduled power stations (meter no. 2). This demand is different from scheduled demand—sent out, in that it also includes the electricity used within the power station.
- *Native demand* is the summation of consumer demand measured at consumers' premises (meter no. 4). This excludes distribution and transmission losses and energy used in-station. It is usually net of any embedded generation, such as rooftop solar.

The demands published and used by the AEMO correspond to scheduled demand (either at the generator terminals or sent out by the power stations). Small generators and embedded rooftop PV are accounted for through a reduced need for generation from scheduled and semi-scheduled generators.

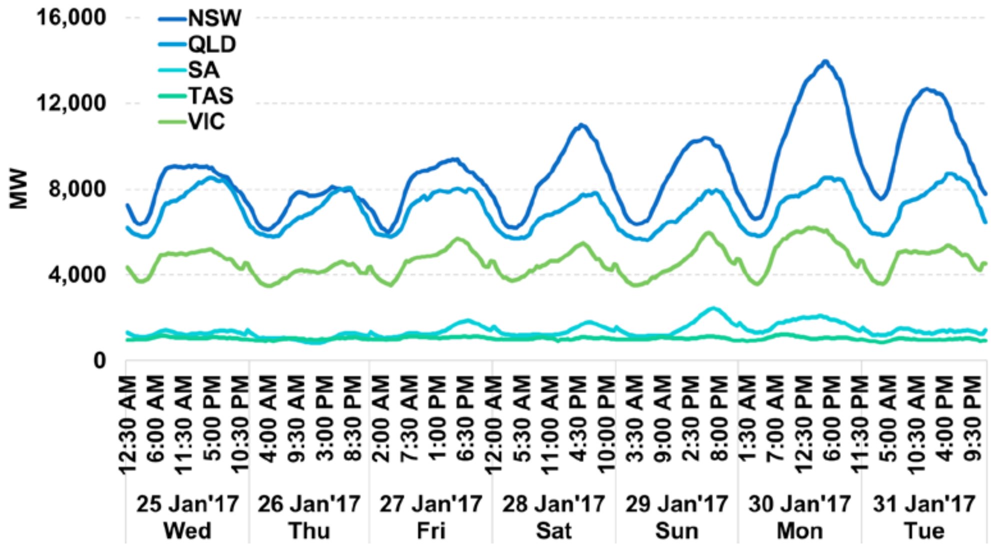
In this report, we also define *dispatchable demand*. This is the demand supplied by scheduled generators only (and can be sent out or at the generator). The importance of this demand is that it defines the demand profile to be supplied by controllable generators (as semi-scheduled generators operate according to the type of renewable source being used).

In this report, *demand* is taken to mean the power (MW) required to be supplied from scheduled and semi-scheduled generators, unless otherwise stated.

To illustrate the nature of demand in the NEM, the scheduled demand profiles for the NEM regions over a week in January 2017 are shown in Figure 8. Of particular note are:

- the respective levels of the regional demands
- the daily variation during the weekdays, which is due to weather conditions
- the low correlation of the extreme maximum demand days between the regions.

Figure 8: Weekly profile of NEM region demands, week commencing 25 January 2017 (MW)



Source: Marsden Jacob, 2017.

3.4 Generator roles in supplying demand

At any point in time, the total amount of power being generated by all operating generators must equal the amount of power being used by all consumers (plus power losses from transmission and distribution lines). This is done by having one or more generators change their outputs to match changes in customer demand, which is termed *load following* or *frequency control.* Load following is achieved by the system operator performing real-time monitoring and dispatching generation and loads (*dispatchable loads*) to ensure that the frequency of electricity supply is maintained at or near 50 Hz.[26]

This section considers the real-time maintenance of the supply–demand balance, first for a 'traditional' power system that has only a small amount of intermittent generation, and then for a power system that has a high amount of intermittent generation. The demand levels and profiles are for illustrative purposes only.

Traditional generator roles

As is described in the following chapter, different generator types have different cost profiles and different flexibilities (such as the time needed to start and stop). Because of this, different generators usually have one of three roles in supplying: base-load, intermediate and peaking:

- *Base-load generators* are generators that tend to run at or near maximum capacity all the time. They are usually characterised by relatively high capital costs and low operating costs (of which fuel is the major cost), which means they have the lowest average cost when used near maximum output. These generators:
  - may or may not have a limited flexibility to follow load
  - have limits on their minimum level of generation without incurring substantial costs (this is referred to as the *minimum generation level*)[27]
  - could be either coal-fired or CCGT generators, depending on the costs of coal and gas.
- *Intermediate generators* are generators that do not operate all the time and are needed to follow load. They are characterised by relatively moderate capital costs and moderate operating costs (of which fuel is the major cost), which implies that they have the lowest average cost when used on most days at variable

26 Hertz (Hz) is a frequency over time measure. In this context, it means the number of cycles (or oscillations) per second.

27 The factors that give rise to the minimum generation level are flame stability in boilers and efficiency levels.

output. They must be capable of following changing demand. Both CCGT and high-efficiency gas turbine plants are suitable in this role.

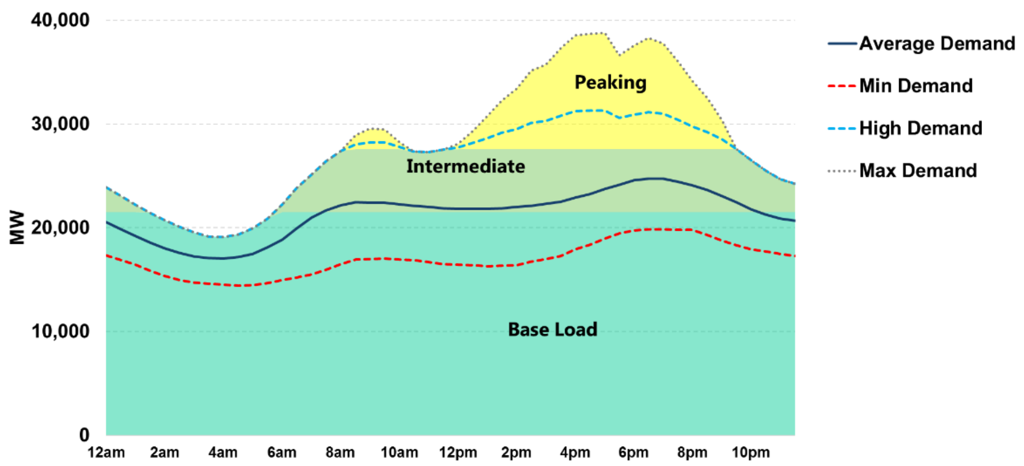
- *Peaking generators* are generators that are used infrequently and mainly for a few hours at a time when demand is high or to 'cover' unforeseen generator outages. They are characterised by low capital costs and high operating costs (of which fuel is the major cost) and must be capable of being started very quickly (within 5 minutes). The most common generator types used in this role are hydro-electric plant (where available) and OCGT plant.
- '*Conventional*' power systems are composed mostly of dispatchable generation, and any operational uncertainty is mainly associated with demand variation and generator forced outages. Demand variation is largely forecastable (depending on the accuracy of weather forecasts), and generator forced outages are infrequent and somewhat controllable. This means that the profile of generation and which generators are to be turned on and off (that is, committed and de-committed) can be planned days in advance. This provides for an orderly operation of the power system and resulting lower costs.

An example of these modes in supplying total demand and how they respond to changes in demand associated with different types of weather over 24 hours are shown in Figure 9. It shows, for a hypothetical market, four potential daily demand profiles corresponding to four different demand levels: average, minimum, high and extreme (referred to as 'max' demand). The colours show the amount of installed capacity of base, intermediate and peaking plant. From this we observe the following:

- Intermediate plant supplies most of the additional demand from average to high, but peaking generation is needed to supply the peak demand.
- Moving from high to maximum demand is associated with increased peaking generation.
- On minimum demand days, there may be too much base-load generation, and some base-load generator units may need to be de-committed.

Forecasts of demand (based on weather and day type) allow the expected running of the individual generators to be planned. The profile of demand and the response of generation to changed demand is typical of a system with little or no intermittent generation.

Figure 9: Generator roles in supplying power—no intermittent generation (MW)



Source: Marsden Jacob, 2017.

The influence of intermittent generation

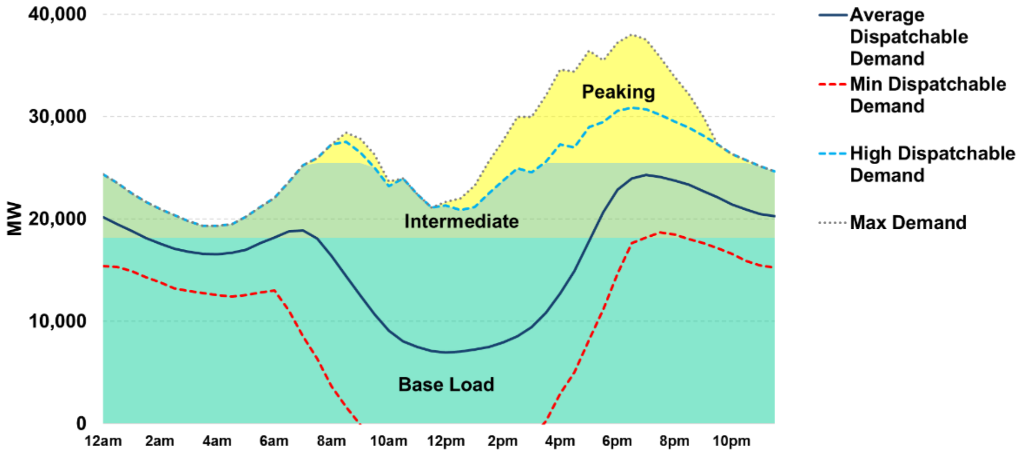
In a system with a substantial amount of intermittent generation, the dynamic is changed.

In this report, we consider the role of dispatchable generation through the demand that those generators are required to supply. To do this, we have defined 'dispatchable demand' as scheduled demand minus intermittent generation. The variable and uncertain nature of intermittent generation increases the variation and uncertainty in dispatchable demand, which can create risks for system operators and dispatchable generators.

An example of the roles that base, intermediate and peaking generation play in a system with a high level of both wind and solar generation is shown in Figure 10. In the same manner as Figure 9, it shows, for a hypothetical market, four potential daily dispatchable demand profiles corresponding to different combinations of scheduled demand and intermittent generation (labelled average, minimum, high and max demand). The colours show the amount of installed capacity of base-load, intermediate and peaking plant. The dip in the middle of the day (referred to as a 'duck curve') is associated with a large amount of solar generation, although it could also correspond to a large amount of wind generation at that time.

This shows that base-load generation is required to operate more in an intermediate role (characterised by generation needing to reduce in the middle of the day and then rapidly ramp up in the evening). Some base-load plant may also be required to be de-committed overnight or on weekends. This means that the economics of the electricity system shift to less base-load generation and more intermediate and peaking generation, at a higher cost.

Figure 10: Generator roles in supplying power—high level of wind and solar generation (MW)



Source: Marsden Jacob, 2017.

3.5 Supply reliability and generator reserves

A key criterion in power system operation and planning is the level of electricity supply interruptions that can be tolerated by customers. This is referred to as *power system reliability*. Reliability of supply to users is the result of the size and reliability of the generation fleet and transmission and distribution systems.

Reliability is considered to encompass two components:

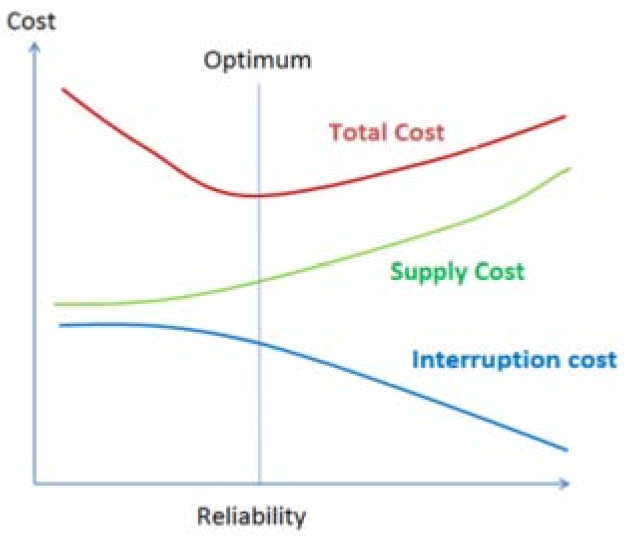
- *Power system security:* This relates to the continuity of power system operation following a major disturbance, such as the sudden failure of a generator unit or transmission line. Power system security can be maintained by having sufficient 'spinning' generation capacity available to replace the failed generator unit or by shedding customer load. Security is expressed as a function of these sort of disturbances the power system should be able to withstand.
- *Adequacy:* Interruptions of supply from the generation system resulting when the level of customer demand is greater than what available generators can supply. This can occur because there are too many generators on outages, demand is very high, or both. To ensure that this happens infrequently (say, only once every 10 years), there is a requirement to have more generator capacity than the highest conceivable level of customer demand. This excess of generator capacity over the forecast maximum level of customer demand is referred to as *generation reserve*.

The NEM has regulated standards of generation reliability that have been developed over time based on the cost of supply interruptions to customers[28] and the marginal cost of increasing reliability (see box). This standard is expressed as having, on average, no more than 0.002% of customer demand not supplied (referred to as *unserved energy*).

The principle of optimal generation reliability

Power systems are developed and operated in a manner that matches the cost of providing generation to the value customers place on reliability, which is termed the *value of customer reliability*.

Optimal economic reliability is achieved when the cost of supply equals the value of unserved energy. To support this, studies are undertaken in the NEM to assess the value of customer reliability[29] and the cost of generation supply.



This graph illustrates the general principles of optimal generation reliability.

It shows an upward sloping curve for generation supply cost (implying the increasing incremental cost of generation supply) and an increasing cost to customers for electricity supply curtailment. Also shown is the total economic cost, which is the sum of those two components.

The lowest cost point on the total cost curve represents the optimal reliability level based on the supply and curtailment costs. This is the point at which the incremental cost of reducing the expected level of load shedding by 1 MWh is equal to the cost to customers of that reduced level of load shedding.

Source: Marsden Jacob, 2017.

3.6 Maintaining 50 Hz frequency—ancillary services

Electricity systems require frequency to be maintained within certain, very tight, limits. For Australian electricity systems, this is 50 Hz plus or minus 0.1 Hz.

Frequency deviations occur when generation supply does not exactly match demand. When there is too much generation, frequency increases; when there is not enough generation, frequency decreases. These imbalances can occur on a second-by-second basis and are not predictable.

Reasons for such imbalances include:

- small changes in demand or generators deviating from what the AEMO has instructed them to do

28 Referred to as the value of customer reliability.

29 Studies of the value of customer reliability in the NEM have proven difficult. They are based on survey results from different classes of customers and different types of supply interruptions (such as time, frequency and duration).

- large changes that can occur when a large generator suddenly and unexpectedly shuts down, or a large demand such as a smelter trips off.
- The way these matters are addressed in power systems is to have sufficient and spare generation that can:
- respond on a second-by-second basis to the normal variations in demand or generator output that occur through time
- very quickly respond to large changes, such as changes caused when a large generator or large load unexpectedly trips.

Power systems are never operated without having *frequency control services* in operation. To do so would jeopardise system security, in that a large disturbance might result in the whole power system shutting down (known as a 'system black').

4. Generator technology and outlook

The cost and performance characteristics of existing and potential new generators are fundamental to the economics of generation supply.

This chapter describes those characteristics for existing and new-generation technologies (non-renewable and renewable).

Key issues in the comparative economics of different generation technologies are:

- *for renewable generation:* the nature of the intermittency and the average $/MWh cost of energy produced
- *for non-renewable generation:* the fixed and variable costs (reflected in the average cost as a function of the capacity factor), the emissions intensity and the flexibility of such generation
- *for all generators:* the outlook for costs, which include capital and, for non-renewables, fuel costs.

The review illustrates that, due to the demand for low-emissions technologies and improvements in those technologies, renewable generation is increasingly becoming an economic alternative to conventional generation technologies.

4.1 Renewable generation technologies

The main renewable generation technologies in use in Australia are solar thermal, solar PV and wind technologies.

Solar thermal

Solar thermal electricity generation technologies use the sun's heat to produce steam (directly or indirectly), which drives steam turbines to generate electricity. The sun's heat energy is concentrated using lenses, reflectors and mirrors to a focal point to heat a fluid (such as water, molten salt or synthetic oil). The most relevant technologies for Australia include:[30]

- *parabolic trough systems*, which concentrate reflected solar radiation onto a focal receiver tube that runs the length of a mirrored trough
- *central receiver systems*, which use flat, sun-tracking mirrors to direct solar radiation onto a focal point (the central receiver) mounted on a tower
- *compact linear Fresnel systems*, which have linear arrays of movable mirrors to focus solar radiation onto a focal receiver tube.

The advantage of solar thermal systems is that, by heating a fluid (other than water), the energy can be stored before it is used to produce steam. In effect, this makes solar thermal technologies a ***dispatchable*** energy

30 US Department of Energy, *Solar explained*, 2016, www.eia.gov/energyexplained/?page=solar_thermal_power_plants [4 August 2017].

source (that is, power output can be varied, unlike wind technologies).

Solar thermal technologies are being deployed overseas, for example, in Spain, Germany and the United States (Figure 11), to provide electricity, and storage systems are also being investigated.

Australia currently has two large-scale solar thermal plants:

- a 44 MW plant at Kogan Creek in Queensland, which uses linear Fresnel technology
- a 9.3 MW facility that has been added to the Liddell coal-fired power plant in NSW.[31]

Figure 11: Solar Reserve's Crescent Dune plant in Nevada

The South Australian Government recently announced the construction of a 150-megawatt solar thermal power plant at Port Augusta to meet 75% of its long-term power requirements.

The plant will cost $650 million to build and will commence production in 2018. It will be able to deliver 495 GWh/year and provide 8 hours of storage capacity (1,200 MWh). It will be the largest plant of its type in the world.32

Source: Solar Reserve, www.theguardian.com/australia-news/2017/aug/14/port-augusta-solar-thermal-plant-to-supply-south-australian-government#img-1 [8 November 2017].

Solar photovoltaic

Solar PV technologies convert sunlight directly into electricity (light photons stimulate electrons and create current). A solar PV cell is a solid-state device that is generally either crystalline silicon or thin film.

Inverters are a key component of most solar PV systems, since the solar power generated is DC power and must be converted, via the inverter, to AC power that flows through electricity grids and on customers' premises.

The main types of PV technology include:

- *fixed flat-plate systems*, which can be mounted on roofs or in a field (in a field array) in a fixed position
- *single-axis tracking systems*, which can track the sun either vertically (from high to low) or horizontally (typically from east to west)
- *dual-axis tracking systems*, which can track the sun both vertically and horizontally and achieve the highest efficiencies for solar PV systems.

Single-axis tracking and dual-axis tracking systems deliver around 30% and 40%, respectively, more annual electricity output than fixed flat-plate systems.[33] A comparison of the power output from tracking and non-tracking solar PV installations is shown in Figure 12. Of particular note is that the additional output extends to

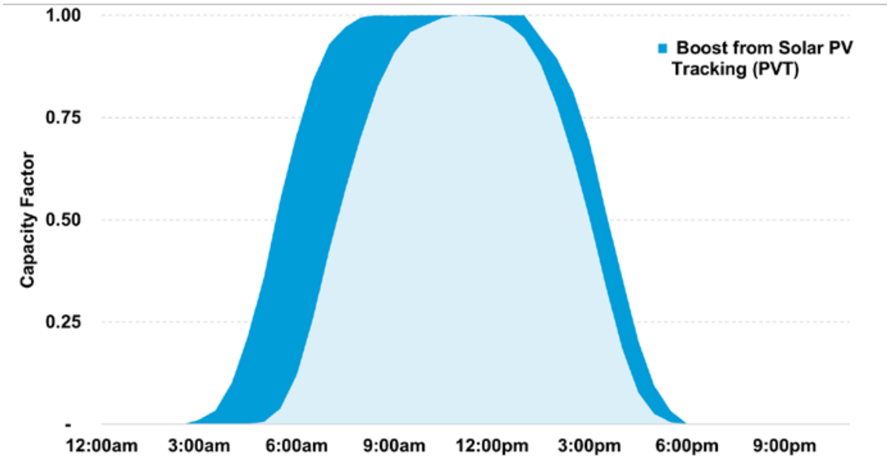
31 AEMO, South Australian fuel and technology report, March 2017, p. 39.

32 'Solar thermal power plant announced for Port Augusta "biggest of its kind in the world"', ABC News, 14 August 2017, www.abc.net.au/news/2017-08-14/solar-thermal-power-plant-announcement-for-port augusta/8804628 [23 August 2017].

33 ABC, 'Solar thermal power plant announced for Port Augusta "biggest of its kind in the world"'.

the time when demand is typically highest.

Figure 12: Comparison of solar PV tracking (single-axis tracking) and non-tracking power output



Source: Marsden Jacob, 2017.

One emerging technology is *concentrating photovoltaics*. These systems consist of concentrators (such as lenses or reflectors) that focus sunlight onto highly efficient PV cells.

The major drawback with PV technology is that it produces electricity only when there is sunlight (for example, fixed flat-plate systems typically have annual capacity factors of only 25%). Without energy storage, solar PV is not dispatchable.

Despite their limitations, solar PV technologies are deployed widely in Australia, mainly on household and business premises. It is estimated that rooftop PV capacity in Australia has reached 4,939 MW.[34] However, this meets only around 3% of Australia's annual electricity requirements.[35]

Wind

Wind turbines capture wind energy within the area swept by their blades. The spinning blades drive an electrical generator that produces DC power. An inverter then converts the electricity to AC power for export to the grid. Multiple wind turbines in an area are typically referred to as a 'wind farm' (Figure 13).

Onshore wind turbines are typically 1.5–3 MW in output and 80–100 metres high). Offshore wind turbines are usually larger than their onshore counterparts (typically 3.5–5 MW and 100–120 metres high) in order to increase output to offset higher construction costs (that is, reduce unit costs).

Wind generation technologies are the most mature renewable energy technologies available and can be expected to continue to develop and deliver improved efficiencies. It is expected that wind blades will be lighter and larger in the future (onshore turbines will typically be more than 5 MW).[36]

Wind generation capacity in Australia was just over 4,300 MW in 2016 and produced around 5.3% of

34 AEMO, National electricity forecasting report 2016, June 2016.

35 Clean Energy Council, *Clean Energy* Australia report, 2016, www.cleanenergycouncil.org.au/policy-advocacy/reports/clean-energy-australia-report.html [2 August 2017].

36 'Growth of wind turbine size', Wind Energy: the Facts, 2009, www.wind-energy-the-facts.org/growth-of-wind-turbine-size.html [4 August 2017].

Australia’s power needs.[37]

Figure 13: The Hallett Wind Farm

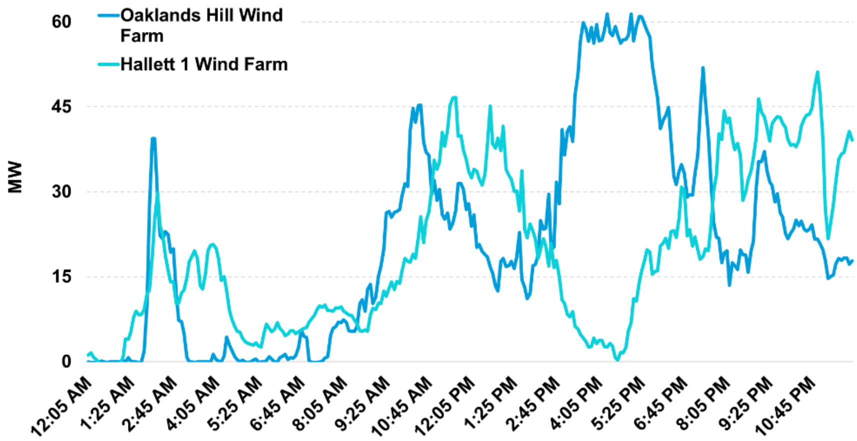
Source: Hallett Wind Farms, no date, www.agl.com.au/about-agl/how-we-source-energy/renewable-energy/hallett-wind-farm [9 November 2017].

The variable nature of wind generation is shown in Figure 14, which shows the 5-minute output from the Oakland Hills Wind Farm in western Victoria and the Hallett Wind Farm in South Australia.

Like solar generation, wind generation is not a dispatchable source, and the variability of wind-farm output (over seconds and minutes) can affect system security and system operation. In particular, maintaining voltage and system frequency can be difficult. Transient stability issues (within 1 to 10 seconds) relate to keeping voltages within required ranges and providing frequency control. Due to the unpredictability wind generation (outside the 10-second period), additional contingency reserve resources are needed to maintain system frequency (that is, to increase the inertia in the system).

In general, wind generation typically requires higher levels of ancillary services to ensure system security when compared to other generation technologies.

Figure 14: Output from a South Australian and a Victorian wind farm on 24 January 2014 (MW)



Source: AEMO data.

37 Clean Energy Council, *Clean Energy Australia report 2016*.

4.2 Non-renewable generation technologies

This section describes non-renewable generator technologies. All of these technologies can be controlled and are referred to as dispatchable.

Gas generation

A gas or combustion turbine burns gas or liquid fuels under pressure in a combustor, producing hot gases that drive a turbine so that the mechanical energy produced drives an electric generator. There are three main types of gas turbine:[38]

- open cycle gas turbines (OCGT)
- Combined cycle gas turbines (CCGT)
- co-generators.

There are also subcritical steam turbines that run on gas. This technology uses gas combustion to power a steam turbine that generates electricity (similarly to coal-fired generation plant, discussed below). This technology is no longer being developed due to its high costs and low efficiency. The existing Newport Power Station is an example of this technology.

Open-cycle gas turbines

OCGT plants combine compressed air with the hot gases produced from burnt fuel (as described above). The efficiencies of OCGT units are typically between 30% and 40%. These generators can start in under 10 minutes and are used in a peaking role.

OCGTs are deployed widely in Australia. Most units have been heavy-frame units. Increasingly, aero-derivative gas turbines (also referred to as high-efficiency gas turbines) that have high pressure ratios and typically have better single-cycle efficiencies and lower exhaust gas temperatures than frame units have been deployed in Australia. However, frame units generally have better combined cycle efficiency, as their high exhaust temperatures permit an efficient steam cycle.

Gas turbines have a number of distinct advantages over other technologies, such as:

- relatively low emissions intensity (for example, 0.4–0.7 tonnes CO_2e per MWh) compared to coal-fired generation technologies (for example, 0.8–1.2 tonnes CO_2e per MWh)
- rapid start-up from cold start (for example, 5 minutes), which makes them ideal for meeting peak demand in the NEM or responding to plant outages
- the ability to ramp up and down rapidly, which makes them ideal for managing fluctuations in demand (for example, performing load following services)

In many cases, gas turbines are able to operate on a variety of fuels (such as gas and distillate).

Given the ability of gas turbines to respond to price spikes (based on 30-minute trading intervals), they have been well suited to providing caps in the NEM (typically for prices >$300/MWh). This helps retailers manage any exposure they have to high prices in the spot market.

Combined cycle gas turbines

A CCGT uses the exhaust heat from one or several OCGT units to generate steam in a relatively conventional boiler to drive a steam turbine. This use of 'waste' heat increases the output from the generating unit for the

38 Electric Power Research Institute, Inc., *Australian power generation technology report*, April 2015, www.co2crc.com.au/wpcontent/uploads/2016/04/LCOE_Report_final_web.pdf [2 August 2017].

same amount of fuel, increasing overall plant efficiency. The efficiencies of CCGT units are typically around 50%.

Their higher capital costs and higher efficiency makes these units suited for intermediate generation.

Figure 15: The Tallawara combined cycle power station in NSW

Tallawarra Power Station (Figure 15) is a 435 MW combined cycle natural gas power station owned by EnergyAustralia.

It is located on the shores of Lake Illawarra in NSW and commenced operation in January 2009.

Source: EnergyAustralia, Tallawarra Power Station, n.d., www.energyaustralia.com.au/about-us/energy-generation/tallawarra-power-station [8 November 2017].

Co-generation

Co-generation usually involves an OCGT producing both heat and electricity. The waste heat is used to boil water to produce both high-pressure steam, which can be used to produce electricity, and low-pressure steam, which can be used in industrial processes. The net efficiency of a co-generation unit is typically more than 50%.

Gas supply

The key disadvantage for gas generation plant, which has only emerged recently on the east coast, is the delivered price of natural gas. When delivered gas prices were in the $3–5/GJ range, gas-fired plant was competitive with coal-fired plant (using black coal) in the NEM. However, mainly because of gas shortages in recent years, due mainly to the export of LNG from Gladstone in Queensland, gas prices have been recorded at around $9–10/GJ, which makes gas-fired plants uncompetitive with coal-fired generators. In addition, gas shortages, especially at peak demand times in the NEM, can reduce the flexibility of gas-fired plant to respond to high spot prices in the market, which can result in severe price spikes (prices >$1,000/MWh). This has contributed to increased price volatility in the NEM in recent years.

4.3 Other technologies

Integrated gasification combined cycle

Integrated gasification combined cycle units can use gas (or syngas) from coal seams or other carbon-based fuels, such as wood waste or municipal solid waste, to produce electricity. They typically use a high-pressure gasifier to produce the gas and then remove impurities prior to power production.

One of the chief advantages of this technology is that it produces concentrated high-pressure CO_2, which makes it easier and less expensive to capture and store the CO_2 gas (see Section 4.2.4 on carbon capture and storage).

Due to the high cost of this technology, there are currently no integrated gasification combined cycle plants in Australia.

Reciprocating internal combustion engines

Reciprocating internal combustion engines are typically used to provide backup power in the NEM. The units are usually small (1–20 MW).

Coal-fired generation

For coal-fired generators, coal is crushed (or pulverised) into a fine powder, fed into a boiler and burned. The heat is used to produce steam that drives a turbine to produce electricity.

Coal-fired power stations are distinguished by the technology and coal type used.

A range of coal-fired power station technologies and coal types are available for use in Australia:

- Power station technologies:[39]
  - *Subcritical:* typical net thermal efficiency of 34–38%
  - *Supercritical:* typical net thermal efficiency of 38–41%
  - *Ultra-supercritical:* typical net thermal efficiency of 41–42%
  - *Advanced ultra-supercritical:* minimum net thermal efficiency of 42%.
- Coal types:
  - *Lignite* (commonly referred to as brown coal) is less than about 40,000 years old. It is characterised by high moisture content (over 70%) and low energy content, and is used in the coal-fired power stations in the Latrobe Valley in Victoria.
  - *Bituminous coal* (commonly referred to as black coal in Australia) is characterised by a moderate moisture content (less than 10%) and good energy content (over 24 GJ per tonne). This type of coal is used in the coal-fired power stations in NSW.
  - *Sub-bituminous coal* is in between brown and black coal. Examples of power stations using this type of coal are Callide and Millmerran in Queensland.

Victorian brown coal power stations

All coal-fired power stations in Victoria use brown coal. The coal comes from dedicated mines and requires drying before combustion. The coal has no value other than to the dedicated power station, and variable fuel costs are very low.

These power stations are subcritical and have very high emissions (in the order of 1.2 tonnes CO_2e per MWh).

39 AEMO, South Australian fuel and technology report, March 2017, p. 39.

Figure 16: Loy Yang Power Station

The Loy Yang A Power Station (

Figure 16) is a 2,000 MW coal-fired power station in the Latrobe valley in Victoria.

It is fuelled by brown coal from a dedicated and adjacent mine. Fully operating, the station requires over 60,000 tonnes of coal a day.

Source: Loy Yang Power Station, n.d., https://www.bing.com [8 November 2017].

NSW black coal power stations

All coal-fired power stations in NSW use black coal. This coal has export value, and the cost of coal to power stations from mines that have the option to physically export coal is typically based on export parity. The coal for the power stations comes either from mines that can export or from mines that have no channel to market and cannot export.

All existing NSW black coal power stations are subcritical and have emissions in the order of 0.9 tonnes CO_2e per MWh.

New high-efficiency, low-emissions technology

Apart from subcritical coal-fired generators, all other technologies are referred to as 'high-efficiency, low-emissions' technologies.

The emissions intensity of supercritical technologies can be around 0.8 tonnes CO_2e per MWh for black-coal-fired generation.[40]

Carbon capture and storage

Carbon capture and storage (CCS) has been touted as a solution to the emissions associated with thermal generation, particularly coal. This technology enables the capture of CO_2 from fuel combustion or industrial processes, the transport of the CO_2 via pipelines, and its storage underground in depleted oil and gas fields and deep saline formations.

In relation to power generation, the proposition is that the CO_2 gas would be captured post-combustion in gas- and coal-fired generators.

CCS technologies have been demonstrated in pilot programs and in conjunction with industrial processes. A range of Australian groups are currently investigating the technical feasibility of CCS technologies and running pilot programs. For example, AGL Energy Limited and Air Liquide announced in 2015 that they have partnered to recover CO_2 at the Torrens Island Power Station site in Adelaide. [41] However, the technology is not yet

40 Electric Power Research Institute, Inc., *Australian power generation technology report*.

41 AGL, 'AGL and Air Liquide partner to reduce carbon emissions', media release, 4 June 2015, www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2015/june/agl-and-air-liquide-partner-to-reduce-carbon-emissions [11 November 2017].

commercially deployed and is unlikely to be viable without a significant price on carbon (implicit or explicit).

This technology has not been proven on a commercial or large scale, its costs are not known, and it is considered unlikely that it will be commercially viable until well into the 2030s.

4.4 Generation technology cost and outlook

The levelised cost of electricity

All other factors being equal, the economics and competitiveness of generation are given by the cost of energy production, expressed as the average cost over the economic life of the power station.

This is expressed through the levelised cost of electricity (LCOE) and is used to assess and compare the competitiveness of different generating (and storage) technologies. It represents the unit cost (c/kWh or $/MWh) of building and operating a generating plant over an assumed financial life and duty cycle (for example, base-load, intermediate and peak).

Calculating the LCOE

Key inputs to calculating LCOE include:

- capital costs (for example, generating equipment, network connection, site construction)
- the capacity factor[42] (a coal plant in Australia would be expected to have a capacity factor exceeding 80%, whereas an OCGT plant may have a capacity factor of less than 5%)
- the WACC (which includes financing costs)
- fuel costs (and the efficiency of the power station)
- fixed operations and maintenance (FOM) costs
- variable operations and maintenance (VOM) costs.

The formula, simply expressed, is as follows:

LCOE = (annualised capital cost + FOM) / capacity factor) + fuel cost + VOM

To calculate unit costs:

- capital costs are annualised over the economic life of the plant and then unitised by dividing the annualised capital costs by the annualised energy delivered over the economic life of the plant
- fuel costs and VOM costs are already unitised and can be simply added.

The annualisation requires an appropriate WACC to be used. The WACC reflects the cost of capital and debt and the project gearing. The cost of capital reflects the risks of the project.

There is a question regarding whether different WACCs should be used for different generation technologies due to the different risks associated with them. On the basis that coal-fired plant has higher risks than renewable generation (arising from potential future environmental policy), this report ascribes higher risks to coal-fired plant compared to other plant.[43] This recognises that, in a perfect market with future policy certainty, the WACC for all projects would not reflect this uncertainty.[44]

42 The percentage of hours the plant is expected to operate in a year.

43 This was also the position taken in the Finkel report. However, in that report it could be argued that, on the basis of policy certainty, the WACCs of all plant should not have reflected this uncertainty.

44 We note that the Finkel report had a substantially high WACC for coal-fired plant compared to renewable generation.

The following WACCs on a pre-tax basis, the details of which are shown in Table 5, are used in this report:

- gas-fired and renewable plant: 7%
- coal-fired plant: 12%.

The higher rate for new coal-fired plant reflects the ongoing risks that federal and state emissions reduction policies could potentially reduce the value of relatively high-emissions technologies, such as supercritical coal, as well as the relatively immature development of CCS technologies that could be used to reduce coal-fired plant emissions.

Table 5: Pre-tax real WACC for types of generators assumed

Generator	Debt %	Generator-specific risk premium[a]	WACC
Coal	40%	9.0%	12.0%
CCGT	60%	7.0%	7.0%
Renewables	60%	7.0%	7.0%

a. Applied to equity capital only. A single flat debt premium applies across all technologies (2%).

Source: Marsden Jacob, 2017.

Generator technology and the LCOE

The LCOEs for different technologies are determined by the relative size of capital and operating costs, the capacity factor of operation and the WACC used.

Table 6 shows:

- capital costs (including connection costs) and FOM costs (which together determine the annual cost that does not depend on the level of generation)
- fuel cost, heat rate and VOM costs, which together define the SRMC.[45]

Table 6: Generator capital and operating costs, 2017

Generator	Capital cost	Fixed O&M $/kW/year	Heat rate	Fuel cost	VOM $/MWh
Supercritical (SCPC)—brown coal	$4,020	$66	12.4	$0.43	$5.00
CCGT	$1,590	$20	7.3	$7.00	$7.00
OCGT	$1,286	$27	9.6	$8.00	$10.30
Wind	$2,200	$40	0.0	$0.00	$0.00
Solar: fixed	$1,536	$25	0.0	$0.00	$0.00
Solar: single-axis tracking	$1,808	$30	0.0	$0.00	$0.00
Supercritical—black coal	$3,210	$51	8.6	$2.40	$4.00

Notes: Costs include connection to the transmission system. Based on lower heat rate.
Source: Marsden Jacob, 2017 estimates.

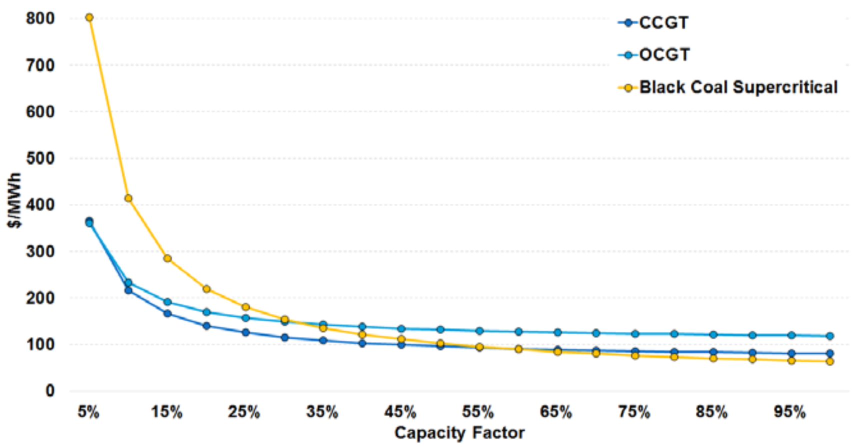
Based on the factors shown in Table 6, the LCOE for the generator types was calculated using the equation

45 The fuel costs for black and brown coal are $2.40/GJ and $0.45/GJ, respectively, in 2017 dollars. Delivered gas costs of $8/GJ are assumed for CCGT and co-generation plant over the forecast period. A premium of $1/GJ is added to the delivered cost of fuel for OCGT plant, reflecting the fact that OCGT plant is run intermittently and makes use of gas storage, spot gas and flexible gas transport arrangements that can result in additional costs for this technology type.

given in the previous section.

As thermal plant can operate at any capacity factor and the LCOE is dependent on the assumed capacity factor of the generator, the LCOE was calculated for capacity factors ranging from 0% to 100%. The results are shown in Figure 17 for coal-fired, CCGT and OCGT generators.

Figure 17: Generator LCOE as a function of capacity factor ($/MWh)



Source: Marsden Jacob, 2017.

What is noticeable is that coal is the lowest cost for high-capacity factor operation, CCGT for intermediate capacity factor operation, and OCGT for peaking capacity factor operation. This reflects their designed mode of operation.

Outlook for the LCOE

A key issue in the economics of the NEM (and indeed all power systems) is the future costs of generation. The costs of mature technologies such as thermal generation are expected to remain fairly constant in real terms, while the outlook for renewable generation is one of reducing costs. The outlook for renewable generation cost reductions is due to both capital cost reductions and increased capacity factors. This is associated with improved energy conversion from wind and from solar technologies' use of tracking systems.

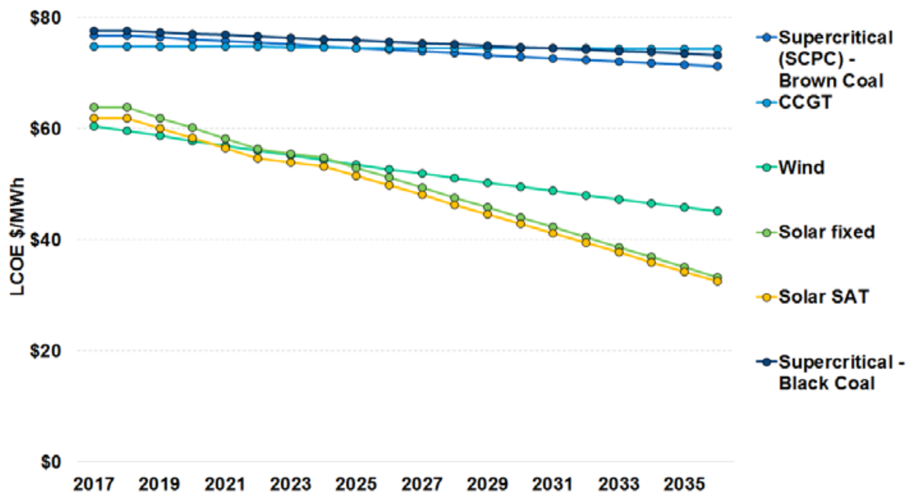
Looking forward, this is expressed in terms of declining LCOE ($/MWh). However, comparing this to thermal generation on an annual basis requires assumptions about the capacity factors at which the various thermal generator technologies would operate. A common approach to this is to assume that thermal generation operates at a 100% capacity factor, as this results in the lowest cost for all technologies.

Figure 18 shows the outlook for capital costs for wind and solar generation, and Figure 19 shows the LCOE outlook for thermal and renewable generation based on all thermal generation technologies operating at a capacity factor of 90%.

Generation with CCS is not included because:

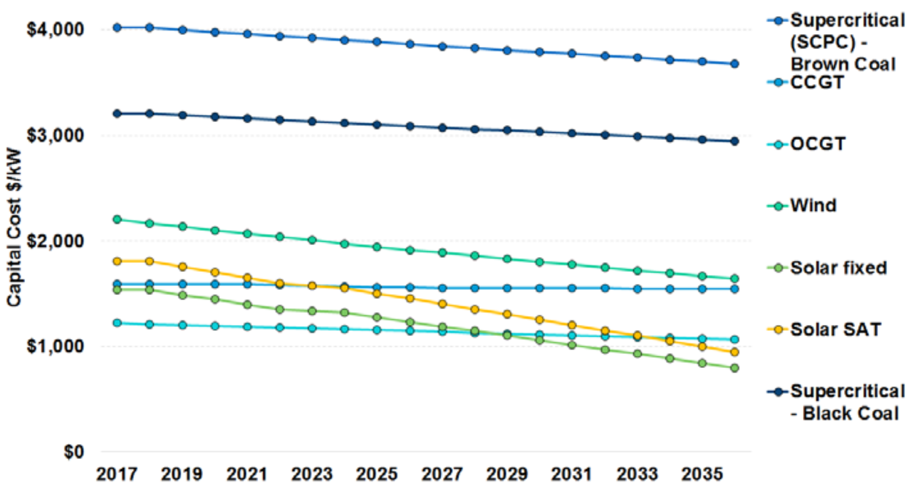
- CCS is not proven, and the earliest time this technology could be viable is after 2030
- if thermal generation is not viable under the assumption of no price on carbon, then such generation would not be economic with CCS regardless of the assumptions on CCS costs.

Figure 18: Capital cost outlook: generator technologies ($/kW)



Source: Marsden Jacob,2017.

Figure 19: Cost outlook: levelised cost of generation ($/MWh, 2017 dollars)



Source: Marsden Jacob, 2017.

5. Energy storage and Snowy 2.0

As has been recognised by reviews such as the Finkel report, the successful integration of intermittent generation into the NEM will require energy storage so that the energy from that source can used when it is most needed.

This chapter describes:

- the viable storage technologies, with an emphasis on batteries and pumped storage
- the outlook for battery costs (and the different ways this is expressed) and how this technology may develop
- the services that batteries and pumped storage can provide.

The chapter also introduces and describes the Snowy 2.0 pumped storage scheme.

Energy storage is characterised by:

- capacity: the maximum power (MW) that can be provided
- the amount of storage (MWh)
- cycle efficiency (the energy losses associated with the recharge and discharge of storage systems)
- cost (usually expressed as $ per unit of storage).

Storage technologies include pumped storage, batteries, compressed air and solar thermal. The most viable and proven technologies for widespread development are batteries and pumped storage.

5.1 Characteristics of energy storage

Energy storage is characterised by:

- capacity: the maximum power (MW) that can be provided
- the amount of storage (MWh)
- cycle efficiency (the energy losses associated with recharge and discharge)
- cost (usually expressed as $ per unit of storage).

The fundamental value driver for energy storage will be energy arbitrage, or the price spread between spot prices at the time of recharge and discharge. This recognises that spot prices are the signal for the economic value of energy and capacity.

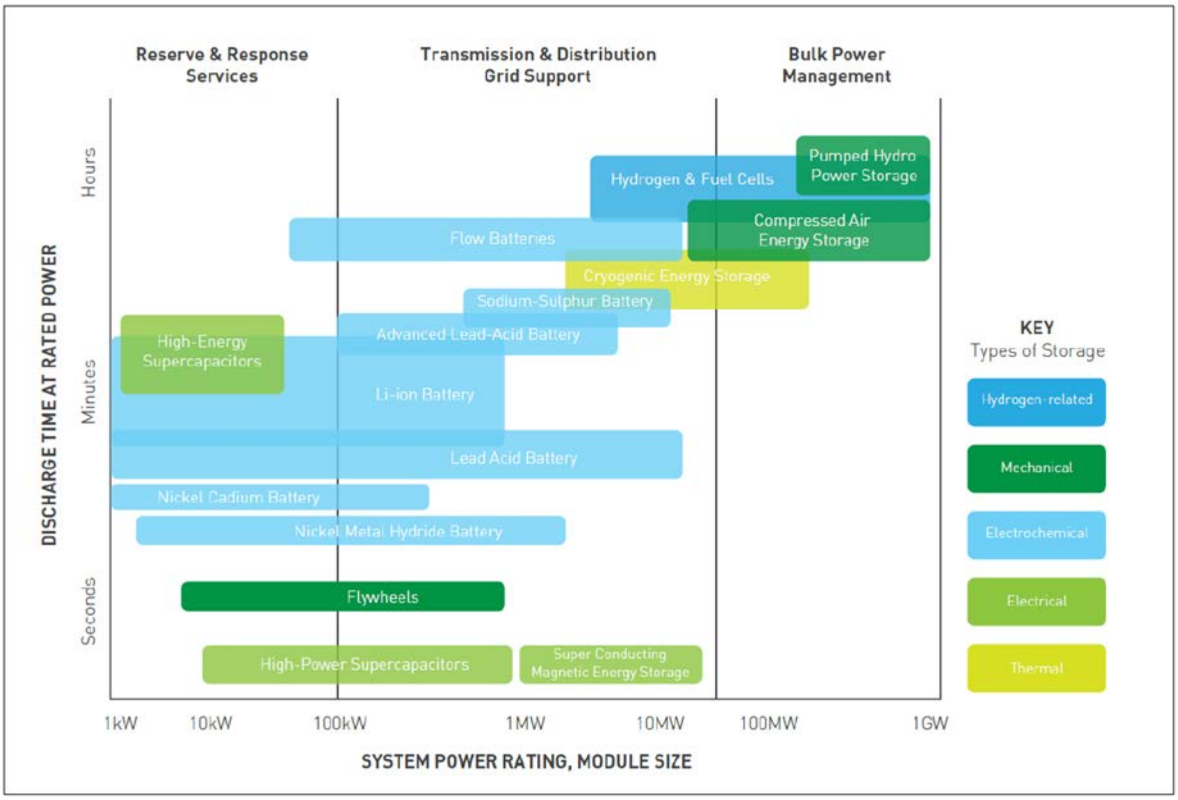
On a per capacity (MW) basis, the value of storage is related to the amount of energy (MWh) it can store. The greater the storage, the greater the arbitrage opportunities and the greater the ability to cover extended periods of generation shortage and high prices. This can be critical in hot summer months, when spot prices can be very high for long periods.

5.2 Storage technologies

A variety of energy storage technologies could be deployed in Australia. They include pumped storage, battery technologies (such as lithium ion), compressed air storage, molten salts and chillers.

Figure 20 shows the different energy technologies that could be deployed and the duration and scale of the services that each technology can provide. Clearly, pumped storage can provide scale (Snowy 2.0 could provide 2000 MW) and duration (up to 10 hours per day), but is limited in its ability to provide network services. On the other hand, battery technologies are typically smaller in scale and can only provide energy for up to 1 hour. However, batteries have a better response time than pumped storage and can be located to overcome local network constraints.

Figure 20: Comparison of the effectiveness of storage technologies



Source: AEMO, South Australian fuel and technology report, March 2017.

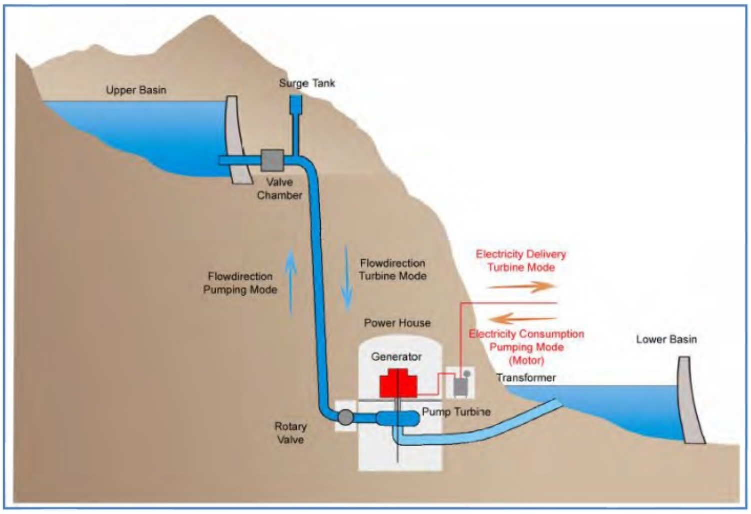
5.3 Pumped storage

Description of the technology

Pumped storage is widely used around the world.[46] It effectively involves pumping water from a lower reservoir to a second reservoir at a higher elevation. This stored potential energy is later converted to electricity by passing the stored water through a generating turbine and returning the water to the lower reservoir (Figure 21).

46 Pumped storage dominates large-scale energy storage globally, reaching 149 GW in 2015 (or 96% of the total installed capacity); AEMO, *South Australian fuel and technology report*.

Figure 21: Typical pumped hydro project



Source: P Dvorak, 'Challenges and opportunities for new pumped storage development', *Wind Power Engineering Development*, 14 August 2014, www.windpowerengineering.com/policy/environmental/challenges-opportunities-new-pumped-storage-development/ [23 August 2017].

Pumped storage is the most mature storage technology currently in use. The efficiency of the cycle is typically about 70% (meaning that for every 1 MWh of pumping the amount of generation that results is 0.7 MWh). Snowy 2.0 is proposed to have a cycle efficiency of 76%. Pumped storage may be expected to operate over a 40–60 year lifetime.[47]

Unlike the deployment of batteries, the deployment of pumped storage is highly dependent on site suitability (such as topography and geology, the displacement between the upper and lower reservoirs and the potential size of the reservoirs).

Existing and potential pumped storage facilities in the NEM

There are currently three large-scale pumped hydro facilities operating in the NEM: Tumut 3 (600 MW in NSW), Shoalhaven (250 MW in NSW) and Wivenhoe (500 MW in Queensland).

Table 7 shows the capacity and storage of each scheme. Storage is expressed as the number of hours the scheme can be operated at full capacity when the upper storage is full.

Tumut 3 pumped storage generation competes with generation already available using water from up-reservoir inflows, meaning that this pumped storage does not provide additional capacity when required. It does provide additional energy-shifting capacity.

Despite the advantages of pumped storage, no large-scale facilities have been installed in the past 30 years in Australia. However, the increasing value of storage arising from intermittent generation is resulting in further investigations into pumped storage, in addition to Snowy 2.0.

47 AEMO, South Australian fuel and technology report.

Table 7: Pumped storage facilities in Australia

Power station	Region	Pump capacity (MW)	Operating hours when storage full
Tumut 3	NSW	600	40 hours
Wivenhoe	Queensland	480	10 hours
Shoalhaven	NSW	240[a]	Large[b]

a. Consists of two generators, at Kangaroo Valley and Bendeela. b. Used to supply water during drought.

Sources: AEMO, *South Australian fuel and technology report*, 2017, p. 52; Marsden Jacob, 2017.

Potential locations

The Australian National University recently published an atlas of potential pumped hydro energy storage sites in South Australia, Queensland, Tasmania and the ACT.[48] The atlas's authors found that there is potential for 5,000 sites.[49] Each site has an energy storage potential of at least 0.9 GWh, and some have storage potential above 100 GWh. For comparison, the proposed Snowy 2.0 has storage potential of 360 GWh. In aggregate, the sites have the potential to supply 15,000 GWh of electricity, which is more than sufficient to accommodate a 100% renewable target for Australia.

Some specific locations are being considered for pumped storage development in Australia. Examples include the following:

- Pumped seawater storage could be viable in locations such as the Portland area of western Victoria. In that case, seawater would be pumped up to a reservoir on coastal hills using low-cost electricity produced by local windfarms. A study by the Melbourne Energy Institute indicated that this type of pumped storage may be economically viable. However, these sites are typically greenfield sites requiring environmental approvals, which might take years to obtain.[50]

48 A Blakers, M Stocks, B Lu, K Anderson, A Nadolny, *An atlas of pumped hydro storage*, Australian National University (ANU), 3 August 2017, http://re100.eng.anu.edu.au/research/phes/ [1 September 2017].

49 The requirements for a location to be considered a potential pumped hydro energy storage site in the ANU study included:

- large head: 300–600 metre heads are desirable (Doubling the head doubles energy and power but often does not double the cost. For comparison, the existing Tumut 3 pumped hydro storage system has a head of 150 metres)
- gentle slopes behind the dam wall so that a modest wall can impound a large volume of water
- large water volumes (a minimum of 1 GL, which roughly corresponds to 1 GWh of stored energy for an approximate 400-metre head)
- a large volume of stored water compared with the volume of rock required for the dam (a ratio above 10:1 is desirable)
- short and steep connecting pressure pipes/tunnels between upper and lower reservoirs to minimise length/cost
- minimum conflicts with Indigenous, environmental, social, heritage, urban, agricultural and land management aspects
- appropriate geological characteristics
- good access to roads, high-voltage power lines and water.

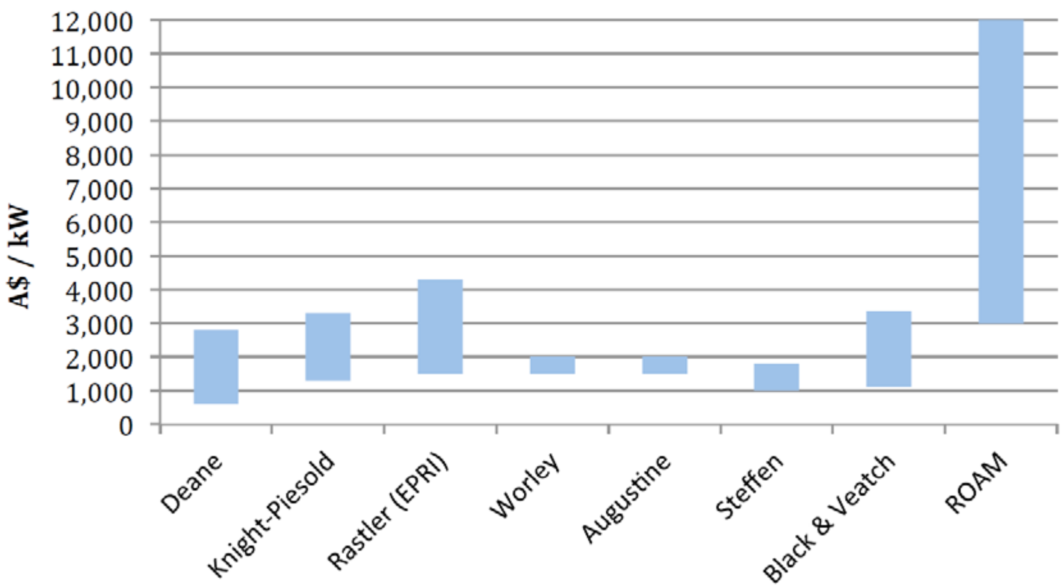
50 Melbourne Energy Institute, Opportunities for pumped hydro energy storage in Australia, 27 February 2014, http://energy.unimelb.edu.au/research/energy-systems/energy-storage-liquid-air-and-pumped-hydro/research/opportunities-for-pumped-hydro-energy-storage-in-australia2 [23 August 2017].

- Some abandoned reservoirs previously used by mines and power generators (such as in the Latrobe Valley[51] and the Kidstone Pumped Hydro Storage Project in Queensland[52]) have sufficient height differentials and could be used to establish a pumped storage facility.
- Given that such reservoirs are part of existing industrial sites (brownfield sites), obtaining relevant approvals might not be as onerous as for the development of greenfield reservoirs on coastal hills in NEM states. However, such a project has not been undertaken in Australia to date.

Potential costs

A review of the potential capital costs of pumped storage in Australia by the Melbourne Energy Institute found that cost estimates vary widely (Figure 22). However, most studies calculated costs in the $1,000–3,000/kW range (2012 dollars). The lower bound costs are significantly below the current capital costs of lithium ion battery systems ($2,500/kW in 2017 dollars).

Figure 22: Pumped storage capital costs ($/kW)



Source: Melbourne Energy Institute, *Opportunities for pumped hydro energy storage in Australia*, 27 February 2014, http://energy.unimelb.edu.au/research/energy-systems/energy-storage-liquid-air-and-pumped-hydro/research/opportunities-for-pumped-hydro-energy-storage-in-australia2 [23 August 2017].

51 The cooling pond at the Hazelwood Power Station (closed in March 2017), in conjunction with the adjacent Morwell coalmine, could be used to provide pumped storage. Locally sourced artesian water could be pumped from the Morwell mine (low reservoir) to the Hazelwood cooling pond (elevated reservoir). There is a height differential of 120 metres between the two potential reservoirs.

52 S Kidston, 'Turning an abandoned gold mine into a renewable energy hub', The AusIMM Bulletin, 2017, www.ausimmbulletin.com/feature/turning-abandoned-gold-mine-renewable-energy-hub/ [4 August 2017].

5.4 Snowy 2.0

This section describes the proposed Snowy 2.0 scheme, its transmission connections and its mode of operation.

Description of the Snowy 2.0 pumped storage scheme

Snowy 2.0 is a pumped hydro storage scheme that would operate between Tantangara Dam (Figure 23; the high reservoir) and Talbingo Dam (the low reservoir).

The development would use a tunnel between the reservoirs, and the pumping/generator station would be located near the low Talbingo reservoir. The name of this new generating station would be Tumut 4, or simply T4. The proposal does not require the construction of any new dams; nor will it affect irrigators and downstream water users.[53]

Figure 23: Tantangara Reservoir

Source: Snowy Hydro, n.d., www.snowyhydro.com.au/our-scheme/snowy20/ [8 November 2017].

The key features of the Snowy 2.0 pumped hydro scheme are:

- *turbines at Tumut 4:* 6 units with a total capacity of 2,000 MW
- period of operation when headwater reservoir is full: 175 hrs = 7.3 days
- *cycle losses:* 24% (76% cycle efficiency).

This capacity would increase the capacity of the Snowy Hydro scheme to 5,720 MW (an increase of 53%).

Transmission

Snowy 2.0 would be connected directly to Bannaby in NSW with a transmission system rated at 2,000 MW. As Bannaby connects directly to the NSW transmission system (and NSW reference node), there are no transmission limits on Snowy 2.0 trading within NSW.

With nearly equal power flows each way on the transmission lines to Bannaby, the marginal loss factor has been assessed as close to 1.0.

To accommodate additional flows from Snowy/Snowy 2.0 to Victoria, the NSW to Victoria interconnector limit would be increased by 1,300 MW.

53 Snowy Hydro Limited 2017, Snowy 2.0, 2017, www.snowyhydro.com.au/our-scheme/snowy20/ [8 November 2017].

In the long term, additional development is also planned to increase the flow limit from Victoria to NSW, which would support pumping at Snowy 2.0. This would increase the flow from Victoria to NSW by around 1,000 MW.

How Snowy 2.0 would operate

The capacity and large storage available at Snowy 2.0 would provide for sustained periods of pumping when prices are low and Tantangara Reservoir is not full, and sustained periods of high generation when demand is high, intermittent or thermal generation is low, or both. It would also provide for improved balancing of existing Snowy Hydro reservoirs because of the flexibility provided by Snowy 2.0.

Snowy 2.0 would operate in response to market needs. This would involve periods of operation where Snowy 2.0 was:

- operating is a repeatable way each day such as generating 8 hours/day and pumping for 10.5 hours/day. Roughly a repeating operating pattern each day will likely be the most common mode of operation
- operating at high output for continuous days in a row. Such operation may be associated with low wind condition across the east coast of Australia and generator outages
- high levels of continuous pumping for continuous days. Such operation may be associated with high wind condition across the east coast of Australia and low demand.

This reflects the uncertainty and variability that has been a characteristic of the NEM and that will increase moving forward.

5.5 Battery storage

The following sections outline different battery technologies and their costs.

Battery technologies

A range of battery technologies could be used to provide energy storage in the NEM.

Lead–acid batteries

Lead–acid batteries are the most commonly used rechargeable battery. They are low cost and are used in numerous applications, including vehicles, off-grid power systems and uninterruptible power supplies. Typical lead–acid batteries have efficiencies of around 70–90% and an expected lifetime of 5–15 years. They typically have lower cycle lifetimes and depths of discharge than other battery types.

Lead–acid batteries have been coupled with many solar, wind and off-grid power systems. However, the declining costs of lithium-ion batteries and their better operating performance (that is, depth of discharge and efficiency) compared to lead–acid batteries has seen this technology displaced by li-ion batteries in many applications.

Lithium ion batteries

Lithium ion (li-ion) batteries are extensively used in portable electronics, and more recently in electric vehicles. Their wide application and use have resulted in cost reductions and increased interest in deploying them ‘behind the meter’ to store surplus energy produced by rooftop PV (for example, Tesla Powerwall units) in Australia and for utility-scale storage to provide network and wholesale services.

Li-ion batteries have long lifetimes (4,000 cycles or 10 years life, if we assume one complete discharge and recharge cycle per day) and are able to store large amounts of energy for their size. They have high round-trip efficiencies (90–95%) and can accept high depth of discharge levels (up to 100%). They have rapid response capability (discharge within 20 milliseconds), making them an ideal technology to provide frequency control ancillary services (FCAS) in the NEM. Given their long life, they are also ideally suited to providing energy arbitrage services on a daily basis.

Flow batteries

Flow batteries (zinc bromine and vanadium redox) are scalable batteries that are also useful for storing surplus energy produced by large-scale intermittent plant. Flow batteries are usually between 65% and 80% efficient, permit up to 10,000 cycles, allow operational flexibility in terms of depth of discharge, and have a short response time.

Lazard.com estimated the levelised cost of battery storage in November 2015 (levelised costs of storage are discussed further in the following section), as shown in Table 8. This shows that, on a levelised cost basis, li-ion batteries have a significantly lower price range (US$355–686/MWh) than flow batteries at the current time (US$373–950/MWh). All batteries are predicted to have substantial falls in levelised costs over a five-year period, and li-ion is likely to be in the US$243–418/MWh range. Large-scale li-ion batteries (100 MW) are about to be installed by Tesla in South Australia.[54] It is likely that more large-scale li-ion batteries will be deployed in the NEM in coming years, and our assessment of energy storage focuses on this battery technology.

Table 8: Levelised cost of battery technologies (US$/MWh, 2015 dollars)

Battery type	Unsubsidised LCOS/MWh (US$)	Capital costs/MWh (US$)	5-year LCOS/MWh with declines (US$)
Flow battery	373–950	662–1,387	282–642
Lead–acid	402–1,068	682–2,072	355–842
Li-ion	355–686	622–1,425	243–418
Sodium	379–957	611–1,751	Not supplied
Zinc	245–345	359–532	239–334

Source: 'Lazard's levelised cost of storage analysis', version 1, *Lazard.com*, November 2015.

Battery cost structure

Cost components

A battery installation and associated costs have three main components:

- the battery
- the inverter (converts DC current to AC)
- the connection to the grid.

The costs of those components are affected by the following factors:

- Battery installations are composed of many connected smaller batteries, and the cost is directly related to the total storage (expressed as MWh).
- The size of the inverter determines the maximum capacity (MW) that a battery installation can deliver. Costs are proportionate to the size (MW) of the inverter.

54 Tesla is installing a li-ion battery array capable of supplying 100 MW of power instantly and able to store up to 129 MWh. It will be co-located with the Hornsdale wind farm in South Australia. N Harmsen, A McMahon, 'Tesla to supply world's biggest battery for SA, but what is it and how will it work?', *ABC News*, 8 July 2017, www.abc.net.au/news/2017-07-07/what-is-tesla-big-sa-battery-and-how-will-it-work/8688992 [accessed 23 August 2017].

- Connection costs increase as the capacity (MW) of the installation increases.

In this report, battery costs are taken to be the total cost, inclusive of inverter and connection, unless otherwise specified.

Expressed battery cost

Battery costs are reported in a number of ways, and care is needed to ensure that the basis of the costs is understood:

- Battery capital cost can exclude inverter and connection costs. This is expressed as $/kWh of nameplate energy storage.
- Battery capital costs can include inverter and connection costs. This is expressed as $/kWh.
- Capital costs are expressed as $/kW of nameplate capacity.
- A battery can be treated as a generator and the LCOE can be calculated based on its economic lifetime and degradation and the capacity factor associated with discharge.

The discharge capacity factor would be expected to be that associated with a daily cycle of charge and discharge. Unlike for a thermal generator, such calculations do not normally include the cost of charging. This is expressed as $/kWh.

The current costs of li-ion batteries expressed in different ways are shown in Table 9.

Table 9: Lithium ion battery costs, 2017

Element	Capital $/kW nameplate capacity	Capital $/kWh nameplate storage	LCOE $/kWh
Battery (lithium ion)	1,800	450	292
Inverter	280	70	45
Connection	330	83	54
Total battery capital cost	2,410	603	391
Total battery capital and operating costs[a]			404

a 4 hours storage, 16.6% capacity factor.

Notes: Assumes 10-year economic life, 40% degradation, 7% real discount rate. The LCOE for the battery excludes the cost of charging. If a battery is charged from coal-fired energy overnight (SRMC of around $20/MWh), this cost must be added to the levelised cost of the battery storage system when compared with conventional generation.

Source: Marsden Jacob, 2017.

Outlook for battery costs

Battery costs have fallen by over 80% over the past nine years,[55] and the outlook is for them to continue to decrease. The key drivers for this are:

- improving technology that includes longer economic life and lower degradation
- increased production driven by markets that include electric vehicles.

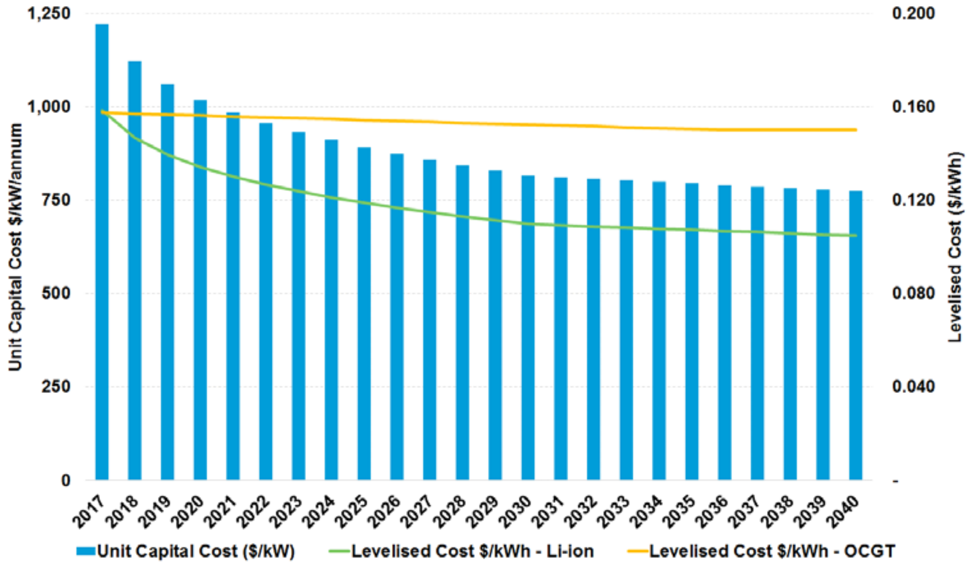
55 According to the International Renewable Energy Agency (IRENA), li-ion battery prices were US$2020/kWh in 2009; IRENA, *Battery storage for renewables: market status and technology outlook*, January 2015. Inflating battery prices to 2017 and comparing with current prices ($450/kWh), we have calculated an 80% reduction in battery storage capital costs.

Noting the uncertainty associated with forward cost projections,

Figure 24 shows the future cost of li-ion batteries expressed on a levelised cost basis (inclusive of inverter and connection costs). The levelised cost analysis is based on the same assumptions used to derive the levelised costs in

Figure 24. This shows that the levelised costs of li-ion batteries are projected to decline substantially over the period from 2017 to 2030.

Figure 24: Past and forecast costs of li-ion battery systems ($/kW/year)



Source: Marsden Jacob, 2017.

Battery economics and development

Batteries have been proposed as an important energy storage technology of the future, as evidenced by the storage auctions held by the South Australian and Victorian governments[56] in 2017.

The level of battery installation that develops will be important to the operation of dispatchable generation and will depend on the economics of batteries in the NEM (assuming Snowy 2.0 is not a competitor).

The services and associated revenues provided by batteries are not confined to energy buying and selling (that is, arbitrage), but include other services and revenues. Battery revenues arise from:

- energy arbitrage: buying and selling energy in the energy spot market. (The introduction of 5-minute pricing, assuming this occurs, which will place value on the rapid response of batteries to capture 5-minute price spikes
- contract sales: the premium associated with any contract sales (the limited storage of batteries limits the contracts that can be sold)
- providing FCAS (such as contingency raise)
- network services, to the extent that they can be provided.

Of these services and based on historical market prices the provision of FCAS is likely to be an important

56 The Australian newspaper reported on 14 November 2017 that the Victorian Government had missed the deadline for the installation of two large-scale batteries (with total storage of 40 MW and 100 MWh) by the summer of 2017–18.

component of revenues for the following reasons:

- The very fast response of batteries allows batteries to provide all the FCAS, including simultaneously providing the 6-second, 60-second and 5-minute contingency raise (the quantity being twice the capacity of the battery).[57]
- Batteries can provide FCAS contingency services continuously (that is, 24 hours per day), while energy arbitrage is limited to the level of storage (possibly 1 or 2 hours per day).

To illustrate an indicative range and comparison of the revenues obtainable from the energy and FCAS markets, two scenarios of the revenues a 1 MW / 1 MWh battery would obtain in the energy and FCAS markets are shown in Figure 25. The figure shows for each market over an assumed 12 year economic life, the price obtained[58] (price spread for energy), volume sold, and associated revenues. The results are also expressed as a present value. The table shows that the sum of the present values of energy and FCAS revenues ranges from $421/kW ($203/kW energy + $218/kW FACS) to $1,040/kW ($385/kW energy + $656/kW FCAS). A comparison to

Figure 24 indicates that batteries will not be economic without subsidies until prices are substantially lower than the current outlook indicates.

Figure 25: Scenarios of battery economics

Energy			NPV 6% WACC	1	2	3	4	5	6	7	8	9	10	11	12
Spot Price Spread	High	$/MWh		200	180	160	140	140	140	140	140	140	140	140	140
	Low	$/MWh		100	95	90	85	80	75	70	70	70	70	70	70
Energy traded/day		MWh		1	1	1	1	1	1	1	1	1	1	1	1
Number days per year				300	300	300	300	300	300	300	300	300	300	300	300
Arbitrage Revenue	High	$k	$385	60	54	48	42	42	42	42	42	42	42	42	42
	Low	$k	$203	30	28.5	27	25.5	24	22.5	21	21	21	21	21	21

FCAS			NPV 6% WACC	1	2	3	4	5	6	7	8	9	10	11	12
FCAS Price	High	$/MWh		12	8	6	5	5	5	5	5	5	5	5	5
	Low	$/MWh		5	4	3	2	1	1	1	1	1	1	1	1
Capacity - sum of all services		MW		1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75
Number days per year				300	300	300	300	300	300	300	300	300	300	300	300
Revenue	High	$k	$656	151.2	100.8	75.6	63	63	63	63	63	63	63	63	63
	Low	$k	$218	63	50.4	37.8	25.2	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6

Source: Marsden Jacob, 2017.

5.6 Solar thermal

As outlined in Section 4.1.1, solar thermal systems can heat fluids such as molten salt or synthetic oil. In effect, the solar energy is stored in those fluids as heat and can be used later to produce steam to drive a generator turbine. This makes solar thermal technologies a *dispatchable* energy source.

The potential scale of thermal storage systems can be significant.

The Ivanpah plant in California was commissioned in 2013, cost US$2.2 billion to build and has a peak

57 The Market Ancillary Service Specification states that the capacity that can be offered in each FCAS contingency service is twice the average level that can be provided over the relevant period.

58 FCAS prices have been higher over the past few years than in the years before, but the increased supply provided by batteries and demand management is likely to result in low FCAS prices and moderate revenue for batteries.

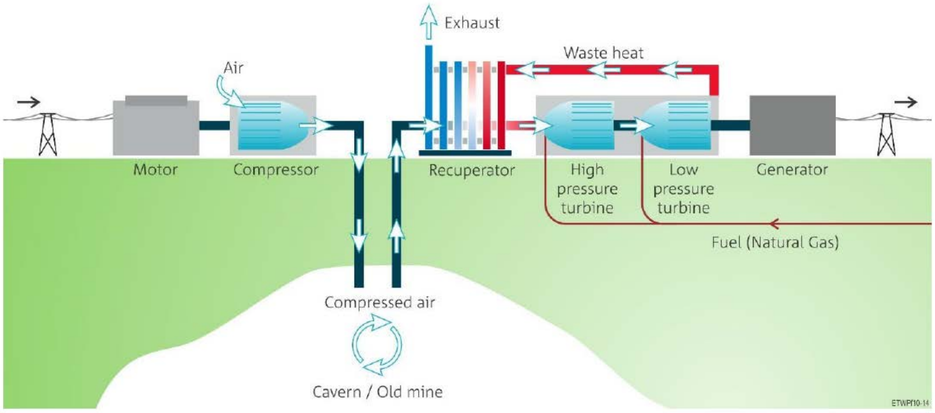
operating capacity of 377 MW.[59] We note that the plant was forecast to produce 940 GWh/year. It produced only 419 GWh in 2014 and increased production to 703 GWh in 2016, which is still short of the forecast generation level. The plant does not have storage capacity.

As outlined above, the South Australian Government recently announced the construction of a 150-megawatt solar thermal power plant at Port Augusta. The $650 million plant will begin production in 2018, deliver 495 GWh/year and provide 8 hours of storage capacity (1,200 MWh). It will be the largest plant of its type in the world.[60]

5.7 Compressed air

Compressed air energy storage (CAES) plants can provide bulk storage similar to pumped storage facilities. In a CAES plant, ambient air is compressed and stored under pressure in an underground cavern. When electricity is required, the pressurised air is heated and expanded in an expansion turbine, driving a generator for power production (Figure 26).[61]

Figure 26: Schematic of compressed air energy storage facility



Source: CSIRO.

Currently, CAES has relatively low round-trip efficiency of less than 50% because the compressed air needs to be reheated prior to its expansion. A higher round-trip efficiency of up to 70% may be achieved through an 'adiabatic' process (which uses heat released from the compression process to reheat the compressed air before its expansion).[62] Adiabatic processes are still in development.

The only two existing CAES plants are in Huntorf, Germany (321 MW discharging), and in McIntosh, Alabama, USA (110 MW). Other facilities based on the adiabatic process are being constructed in Cheshire, United Kingdom (40 MW).[63] Preferable locations for CAES plants are in artificially constructed salt caverns in deep salt formations. A CSIRO study into energy storage options indicated that there are limited potential deployment

59 National Renewable Energy Laboratory, Ivanpah solar electric generating system, 2014, www.nrel.gov/csp/solarpaces/project_detail.cfm/projectID=62 [8 November 2017].

60 ABC, 'Solar thermal power plant announced for Port Augusta "biggest of its kind in the world"'.

61 Energy Storage Association, Compressed air energy storage, 2017, http://energystorage.org/compressed-air-energy-storage-caes [8 November 2017].

62 Energy Storage Association, Compressed air energy storage.

63 K Cavanagh, JK Ward, S Behrens, AI Bhatt, EL Ratnam, E Oliver, J Hayward, Electrical energy storage: technology overview and applications, prepared for the AEMC, EP154168, CSIRO, Australia, 2015.

sites in Australia.[64]

5.8 Tasmanian Hydro and Basslink 2

The Hydro Tasmania system has significantly more capacity (2,136 MW) than Tasmanian demand (high load factor demand, with a maximum demand of 1,398 MW projected by the AEMO in 2021–22). This means that Hydro Tasmania can control hydro-generation to manage flows across Basslink (which has limits of 600 MW flow to Victoria and 480 MW to Tasmania) that arbitrage Victorian spot prices in the same manner as a storage plant.

There have been proposals to increase the interconnection to Tasmania via a second undersea cable that has been referred to as Basslink 2.[65] The economic rationale for this is understood to be to support renewable generation development in Tasmania and to limit the risk that this generation would be stranded should industrial demand, such as smelter demand, close (under such circumstances, the current capacity of Basslink would be totally used in exporting hydro-electricity to Victoria).

The requirement for a level of hydro-generation to be operating in Tasmania for stability reasons, the spare hydro capacity above Tasmanian demand and the constraints on Tasmanian hydro-generation indicate that there is limited potential to have Tasmanian Hydro regulate flows across an increased Basslink capacity in the manner of a storage facility. For this reason, an increased Basslink is not considered to be able to address the requirements of increasing intermittent generation.

5.9 Comparison of storage technologies

Given that the only other viable and potentially large-scale storage technology is battery storage, this section compares the Snowy 2.0 pumped storage scheme to what could be provided by batteries. The comparison is summarised in Table 10 under the service categories of energy, FCAS and network support.

Table 10: Comparison of Snowy 2.0 and batteries

		Snowy 2.0	Battery
Energy	Support continuous on days of high demand	Yes	Limited
	5-minute response	Yes—must be operating	Yes
	Support cap contracts	Yes	Limited - high risk
FCAS	Fast response	Yes—must be operating	Yes
	Delayed response	Yes—must be operating	Yes
	Slow response	Yes	Yes
Grid support	Thermal constraints	-	Limited
	Inertia	Yes	Limited
	Fault current	Yes, but limited due to location	No

Source: Marsden Jacob, 2017.

64 Cavanagh et al., Electrical energy storage: technology overview and applications.

65 Department of the Environment and Energy, Second Tasmania Interconnector, 2017, https://www.environment.gov.au/system/files/resources/46a09b64-4267-487a-ace0-62afd84c754e/files/app-c-aemo-report-second-tasmanian-interconnector.docx [21 November 2017].

PART C: The NEM and participant economics

The economics of particular technologies and how they are used are influenced by the market arrangements of the NEM.

Chapter 6 gives a concise review of the NEM and its structure, rules and operation. The roles of both generators and retailers are described.

Chapter 7 explains and comments on the likely impact of the AER's draft determination to introduce 5-minute pricing. It explains in some detail the reason this particular reform and the impact it will have on peaking generation and the sorts of products sold by those generators. Snowy 2.0 would be a large supplier of such products.

Chapter 8 describes the economic criteria for generation entry and closure in the NEM and the impact that increasing levels of intermittent generation would have on the operations and economics of coal-fired generation.

6. NEM overview

This chapter describes the economic basis of the NEM. Similar to the introductory definitions and concepts provided in the previous chapters, much of the information outlined in this chapter can be found in other reports. The understanding outlined in this chapter underpins analysis presented elsewhere in this report.

The NEM refers to:

- the way energy prices are determined and the factors that determine them
- the economics of the various generator types in the NEM and the market setting to ensure that supply reliability is maintained
- the signals for economically efficient outcomes
- how the costs of generation are reflected in the energy prices that retail consumers pay
- how investment decisions are made.

6.1 The NEM

The NEM is a competitive electricity market for the supply and purchase of wholesale electricity. Run by the market and system operator (the AEMO), it covers the states of Queensland, NSW, Victoria, South Australia and Tasmania and the ACT. Western Australia and the Northern Territory are not connected to the NEM transmission grid and are not part of the NEM.

A key feature of the NEM is the open access arrangement that provides for the use of the transmission and distribution systems. This is a set of rules under which generators and wholesale customers can connect to the transmission or distribution system and participate in the NEM.

The jurisdictions that participate in the NEM are connected by transmission lines (referred to as *interconnectors*), which have limited capacity to transfer power. Tasmania is connected by Basslink, which is a high-voltage direct current link from Victoria.

Like many electricity markets, the NEM operates on the concept of a virtual electricity pool. Under this concept, all electricity generated is traded through the electricity 'spot' market. The electricity pool forms the basis of the spot market, in which generators are paid for electricity they sell into the electricity pool and wholesale customers (mainly retailers who on-sell to retail customers) pay for electricity they purchase from the pool.[66]

The NEM is divided into regions that correspond very closely to the state and territory boundaries. Each region has a separate spot price (calculated in each 5-minute period), which is referenced to the regional reference node of that region (the location of the largest load centre in the region). The regional spot prices are related

66 Technically, the NEM is an energy-only gross electricity market. There are no payments for capacity and no requirements for electricity suppliers to obtain capacity.

to each other by the transmission losses and power flow limits on the interconnectors that join the regions together.

Figure 27 shows the NEM regions, including regional reference node information and interconnectors. The arrows are not drawn to scale.

Figure 27: Regions and interconnectors in the National Electricity Market

Interconnectors

QLD-NSW

Queensland – NSW Interconnector

Direct link (DC)

NSW-Vic NSW to Victoria

VIC - SA Victoria to SA

Murray link (DC)

VIC - TAS Basslink (DC)

Source: ASX, 8 November 2017.

The market operates on a half-hourly basis. For each 5-minute period, generators offer to sell electricity into the pool by submitting price ($/MWh) and volume (MW) bands to the AEMO (up to 10 price/volume bands per generation unit are permitted). Using sophisticated computer systems, the AEMO determines the amount each generation unit is to supply for that 5-minute period (accounting for interstate electricity flows on the interconnectors), such that the total cost of supply to meet the total demand in the NEM is minimised. In each region, the cost to supply an additional MWh at the regional reference node sets the spot price for that 5-minute period.[67]

The spot price is calculated, and the market is settled on a half-hour period by taking the average of the six 5-minute dispatch periods in that half hour.

Payments by retailers and revenues to generators (known as 'settlements') are calculated as the metered quantity of electricity bought or sold each half-hour (measured using special meters) multiplied by the spot price for that half-hour period and multiplied by the marginal loss factor at the location of the party selling or buying.

As spot prices are not known in advance, parties enter into hedging contracts that have an agreed price for the purchase and sale of wholesale electricity (this is discussed further below).

6.2 Interconnectors

The reason the NEM is composed of regions connected by notional interconnectors is that the power flows

67 This cost is referred to as a *marginal cost*. It is obtained from the shadow price of generation / demand balancing constraint from the optimisation undertaken.

between regions can often reach power flow limits. When this occurs, more available and lower cost generation in the exporting regions cannot be used, and high-cost generation is needed in the importing region. During such periods of 'interconnector constraint', the spot prices between the two regions where flow is constrained diverge, based on the different marginal generators in the respective regions.

The regionalisation of the NEM and the consequent introduction of notional interconnectors between regions was associated with spot price signals and the expected period for which transmission to or from a particular area or state would be constrained.

The value and economics of joining the state power systems (via the interconnectors) derives from generator reserve sharing between the joined regions, increased use of lower cost generation, and increased generation competition:

- A 'rule of thumb' for the optimal amount of interconnection between regions is that it should equal the difference in maximum demands between the regions, plus the size of the largest unit. This expresses the amount of reserve sharing that can be used. With increasing levels of intermittent generation, the potential level of reserve sharing between regions is increasing.
- The potential to use lower cost generation in one region to save high-cost generation in the other can provide substantial value. Increasing gas costs and intermittent generation are increasing the length of periods of high cost differences between regions.
- Interconnectors also affect generation competition and spot price outcomes as a result of increasing the amount of generation in other states that can supply a state's demand. The impact on spot prices at high-demand times can be substantial. While such considerations are not included in the regulatory test[68] for the assessment of the value of new or upgraded interconnection, increased competition on spot prices can provide substantial benefits to customers.

The existing interconnectors improve overall supply reliability and the security of the power system. For example, a drought in Tasmania in late 2015 meant that the region's energy demand could be supplied by importing energy from Victoria via the Basslink interconnector.[69]

In the past, South Australia has benefited greatly from its interconnection with Victoria. All dispatchable generation in South Australia is now gas-fired (with high operating costs), and the state has a substantial amount of wind generation (consistent with South Australian Government policy to reduce the emissions intensity of its electricity sector). The significant investment in wind generation means that South Australia exports power when wind generation is high but it must import power when South Australian electricity demand is high, wind generation is low, or both. As a result, South Australia has become highly dependent on supply using the South Australian – Victorian interconnectors, which has made it vulnerable to power shortages when those interconnectors have planned or forced outages. Power outages occurred in November 2015 due to interconnector failures.[70]

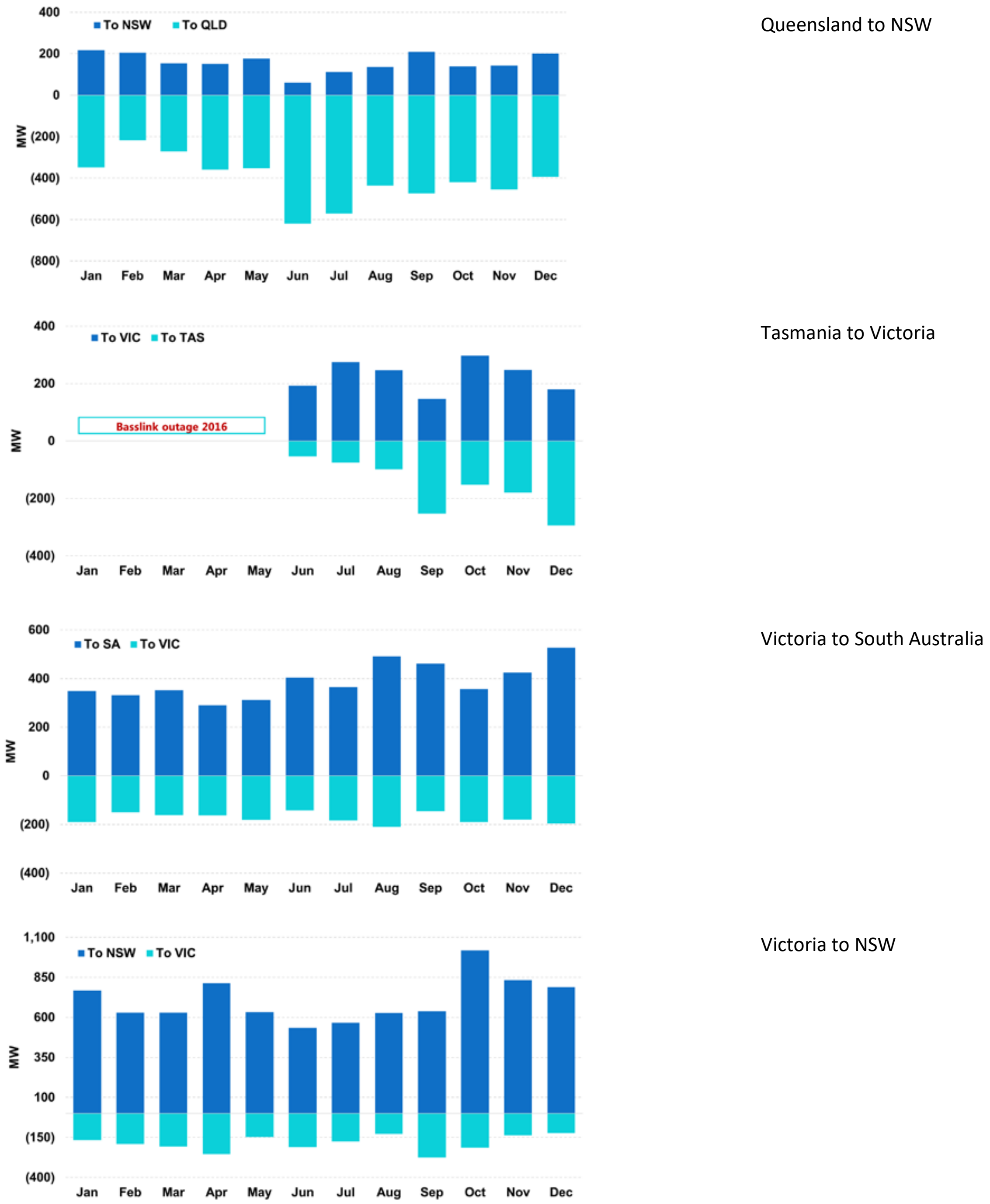
Figure 28 shows the volume of energy transfers between the NEM regions in both directions in 2016.

68 The regulatory investment test—transmission (RIT-T) is based on economic savings and does not account for wealth transfers. However, it does account for the impact that competition has on economic costs.

69 A Basslink outage from late 2015 to May 2016 curtailed all trade with Victoria and resulted in a range of measures being implemented to avert blackouts in the Tasmania, such as recommissioning generation plant, installing temporary diesel plant and demand-side management.

70 'Power blackouts across South Australia after electricity interconnector fails', *ABC News*, 2 November 2015, www.abc.net.au/news/2015-11-02/electricity-interconnector-fails-power-blackouts-south-australia/6904062 [8 November 2017].

Figure 28: Interregional interconnector flow, NEM, 2016 (MW)



Sources: AEMO, Marsden Jacob, 2017.

6.3 Existing generation fleet and operation

Composition of generation types

Figure 29 and Figure 30 show the amount of installed scheduled generation capacity installed (as at 1 July 2017) and the generation level by fuel type, by state and for the NEM as a whole for the 2016–17 calendar year. These graphs exclude rooftop solar PV, which provided about 5,000 GWh of supply.

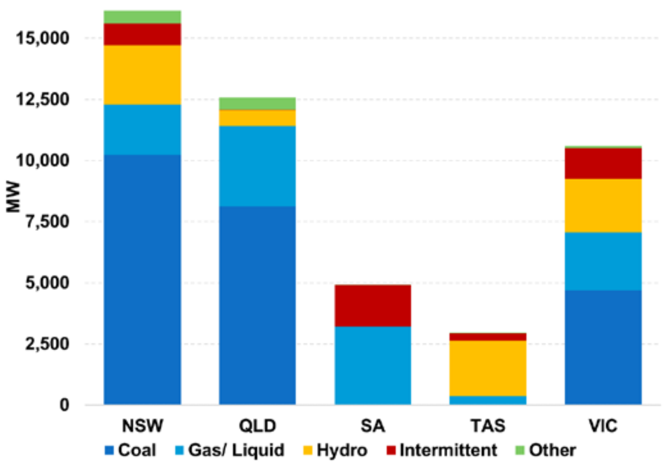
Our observations include the following:

- Except for South Australia, the quantity of intermittent generation installed can be described as moderate.
- Coal-fired generation accounted for 52% of registered capacity and supplied 76% of total electricity generated in 2016–17. Victoria, NSW and Queensland rely on coal more heavily than do other regions.
- Gas-powered plant accounted for 19% of registered capacity in 2017, but supplied only 7% of electricity generated. OCGT plant is typically used to provide peaking power in the NEM. South Australia is the region that relies the most on gas-powered generation.
- Hydro-electric generators accounted for 17% of registered capacity in the NEM in 2017 and supplied 10% of electricity generated. Hydro-generators are located in Tasmania, NSW, Victoria and Queensland.
- Wind generators accounted for 7.5% of capacity and supplied 6.1% of electricity generated in 2016–17. The penetration of wind power is high in South Australia, where it made up 36% of capacity and met 38% of the state's electricity requirements in 2016–17. On windy days, wind generation can account for more than 12.5% of all electricity generated in the NEM.
- Utility solar generators account for only 232 MW of capacity in the NEM. However, funding by the Australian Renewable Energy Agency has helped to ensure that another 11 solar projects will be constructed in the NEM.[71]

Currently, renewable energy makes up only a small proportion of generation in the NEM. However, with the retirement of ageing coal plant and continued investment in renewable energy, it will have a significantly more prominent role in the market in future.

However, the intermittency of renewable sources creates problems for system operators and planners, since this type of plant cannot always be available to supply high loads or respond to unexpected plant outages.

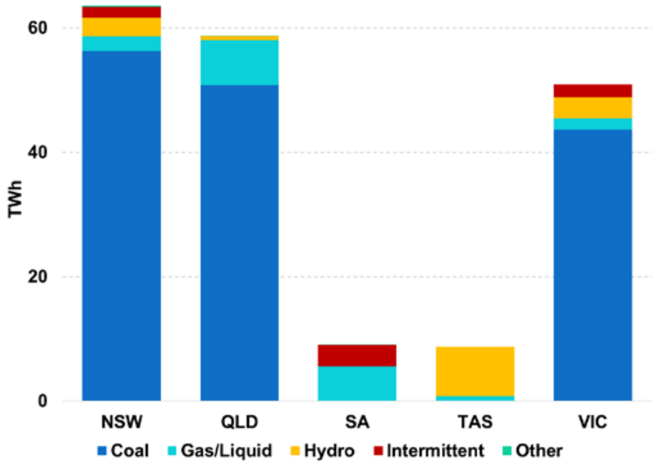
Figure 29: Installed scheduled generation capacity, by fuel type, 1 July 2017 (MW)



Sources: AEMO data; Marsden Jacob, 2017.

71 Australian Renewable Energy Agency, 'Historic day for Australian solar as 12 new plants get support', media release, 8 September 2016.

Figure 30: Production by scheduled generation, by fuel type, financial year 2016–17 (GWh)



Source: AEMO data; Marsden Jacob, 2017.

Industry structure

The original design of the NEM (in the 1990s) was based on the structural separation of generators and retailers and ensuring that there were a sufficient number of major competitors in each market to ensure competitive outcomes in each region.

The major benefit of splitting generation and retailing was competition in both wholesale and retail. This also provided for the development of a liquid hedge market that enabled participants to manage spot market risk. It also helped to encourage many new entrants into various regional markets by making available surplus power.

Over the past decade, many retailers reintegrated with generators to form ‘gentailers’ that own portfolios in both generation and retail. The ‘big three’ retailers—AGL Energy, Origin Energy and EnergyAustralia—now supply about 70% of retail electricity customers in the NEM. While increasing their retail market share, they now own around 48% of generation capacity in the market.[72]

Vertical integration brings benefits for participants. It enables them to better manage their supply chains and to manage price and volume risk in the market. However, the downside is that it increases the market power of the large entities and reduces market liquidity in contract markets, which has the potential to increase barriers to entry for new participants.

New scheduled generation, such as Snowy 2.0, would substantially increase the level of scheduled generation operating in the market and would increase generation competition.

6.4 Ancillary services—frequency control

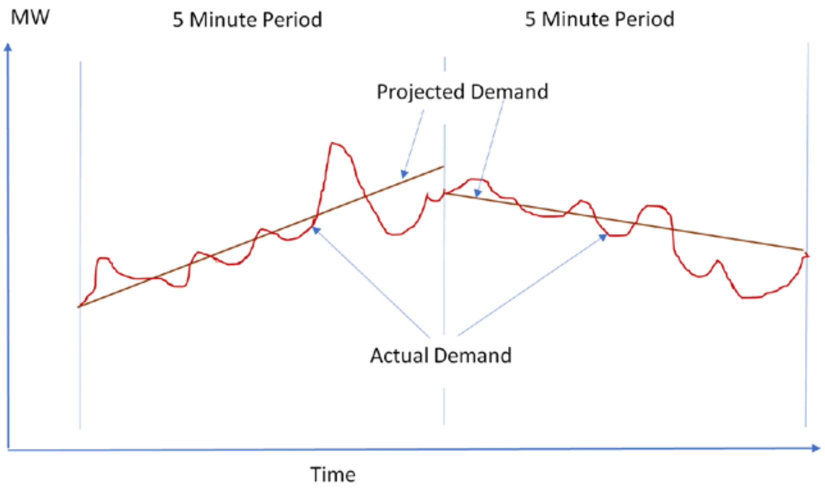
The NEM has spot markets for the provision of frequency control ancillary services or (FCAS) (Appendix 3 provides a detailed overview of the ancillary service markets in the NEM).

“FCAS” services are classified as follows:

72 AER, State of the energy market, May 2017, www.aer.gov.au/publications/state-of-the-energy-market-reports [8 November 2017].

- The small adjustments in generator operation that are needed to maintain system frequency are provided by *regulation services*. These services apply under normal operating conditions (Figure 31).
- For major changes in system frequency due to 'contingency events such as the loss of a major generation unit or lass of a large load (such as a smelter), the *contingency services* are provided to restore the demand and supply balance (and consequently system frequency). This includes generator response and load shedding.

Figure 31: Illustration of regulation requirements—projected and actual and demand



When actual demand is above the projected demand, additional regulating generation is needed; when it is below, less is needed.

This is the 'regulation raise (lower)' service.

Source: Marsden Jacob, 2017.

Currently, there are eight markets for frequency control ancillary services (FCAS):

- two regulation services (regulation raise and lower)
- six contingency services (6-second, 60-second and 5-minute raise/lower services).

The 'raise' and 'lower' terms refer to the service providing either increased generation (raise) or decreased generation (lower).

It is expected that the increase in intermittent generation will increase the requirements for regulation services, since deviations in both scheduled demand and non-dispatchable generation will increase.

Typically, dispatchable generators (also known as *synchronous generators*) produce alternating current using a heavy spinning rotor that provides synchronous inertia, slowing down the rate of change of system frequency.

This highlights the importance of dispatchable generators in helping to maintain system frequency. Synchronous generators also help in voltage control by producing and absorbing reactive power[73] and also provide high fault current to improve system strength[74].

6.5 Retailers

Retailers are entities that bundle all the components (and associated costs) involved in supplying electricity to consumers—wholesale energy, transmission, distribution, ancillary services and market overheads (AEMO costs)—and provide electricity to consumers mostly at fixed tariffs.

Wholesale energy and ancillary service prices are not known in advance and are determined by the market.

73 Reactive power is a technical terms and refers to the relationship between AC voltage and AC current being produced by a generator.

74 System strength refers to the stability of voltage when a location of the transmission system is subject to a fault.

The other components are regulated, known in advance and passed through to consumers at cost. The most significant uncertainty is associated with wholesale energy purchases, which typically account for 32–36% of total electricity costs.

Retailers face a natural risk from uncertain wholesale energy purchase costs while offering their customers fixed tariffs (Figure 32).

The uncertain and variable nature of future spot prices requires retailers who typically sell at fixed retail prices to reduce the risk of high energy purchase costs.   For generators, these risks arise from uncertain future revenues.

Figure 32: Retailer wholesale energy purchase price risk

Source: Marsden Jacob, 2017.

For this reason, NEM retailers typically seek to 'hedge' large proportions of their energy spot price exposure (associated with wholesale energy purchases) by buying financial derivative contracts or by developing their own generation to supply their demand (that is, by vertical integration).

Hedging contracts exchange an uncertain spot price for a known and agreed contract price (the types of contracts that do this are discussed in the next section).

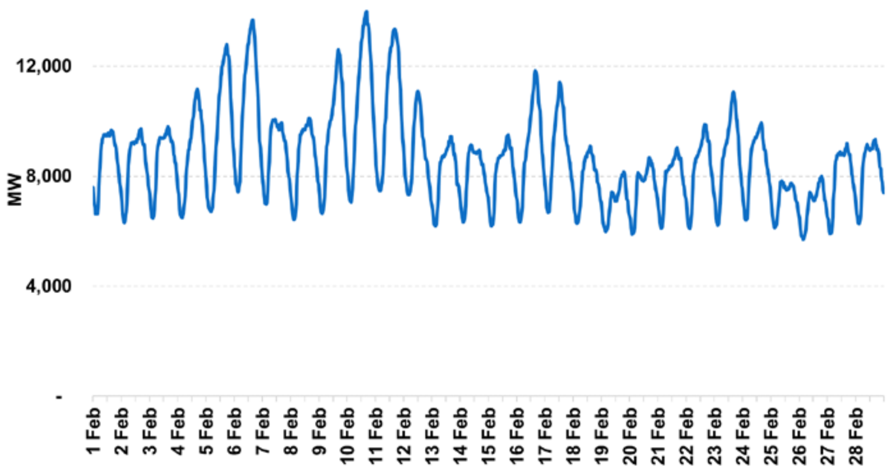
In addition to price uncertainty, the amount of customer demand that a retailer is supplying in any half-hour (and on any day) is uncertain. This uncertainty arises mainly from the impact of weather on electricity use, although there are other uncertainties.

The management of the variation and uncertainty of electricity use by consumers requires contracts that can cater for the uncertainty about the volume of customers' electricity use.

Retailers also arrange with suitable customers to have those customers reduce their demand to avoid forcing the retailer to pay high spot prices. This is referred to as *demand management*.

Figure 33 shows the 30-minute demand for NSW for February 2017. The influence of weather, which results in some days having much higher demand than others, is evident.

Figure 33: NSW scheduled 30-minute demand, February 2017 (MW)



Source: Marsden Jacob, 2017.

6.6 Derivative contracts

A functioning and liquid derivatives market is fundamental to the operation of a spot electricity market. As described in the previous section, retailers typically seek to hedge a large proportion of their exposure to spot prices through buying or selling financial contracts, by obtaining physical generation, or by contracting for demand-side response.

Without contracts, generators are subject to uncertain cash flows, so they also seek to hedge future cash flows by contracting at an agreed price (most often based on projections of future spot prices).

Wholesale electricity contracts are traded on the Sydney Futures Exchange and through brokers in the over-the-counter market.

The common contract products sold in the NEM include the following:

- A *base-load swap*[75] is an agreement to exchange the NEM spot price in the future for an agreed fixed price for a volume of energy used over a 24-hour period. Settlement is based on the difference between the future spot price and the agreed fixed price. Forwards are called 'swaps' in the over-the-counter market and 'futures' on the Sydney Futures Exchange. Swaps can be purchased quarterly, by calendar year and by financial year. They are usually provided by base-load generators (such as coal-fired or CCGT generators).
- A *peak swap* is similar to a base-load swap, except that the fixed price applies only to the volume of energy consumed during peak hours in the NEM (that is, a peak swap contract relates to the hours from 7.00 am to 10.00 pm Monday to Friday, excluding public holidays). Peak swaps are usually provided by CCGT plants in the NEM.
- *Caps* allow the buyer to set an upper limit on the price that they will pay for electricity. For example, a $300/MWh cap ensures that a buyer will pay no more than $300 per MWh for an agreed volume of electricity. Caps are typically sold for a nominated quarter. They are usually sold by OCGT peaking units or hydropower plants in the NEM.

75 The full name is a 'fixed for floating price swap'. A swap contract works as follows. For a nominated quantity of power or energy (MW or MWh), the seller of the swap, usually but not necessarily a generator, agrees to pay a specified floating price (a nominated regional reference spot price) in exchange for receiving the agreed fixed price from the buyer of the swap. Assuming that the seller is a base-load generator and generates an amount equal to the notional swap quantity every trading interval, the swap has the effect of providing the generator with a fixed (hedge) price for its generation.

All of the above contracts are purchased before the period they are hedging. The time before they apply can vary from weeks to years. This means that for a given period, say the first quarter of 2018, the hedging contracts in that quarter can have quite different prices depending on when they were purchased.

Retailer hedging

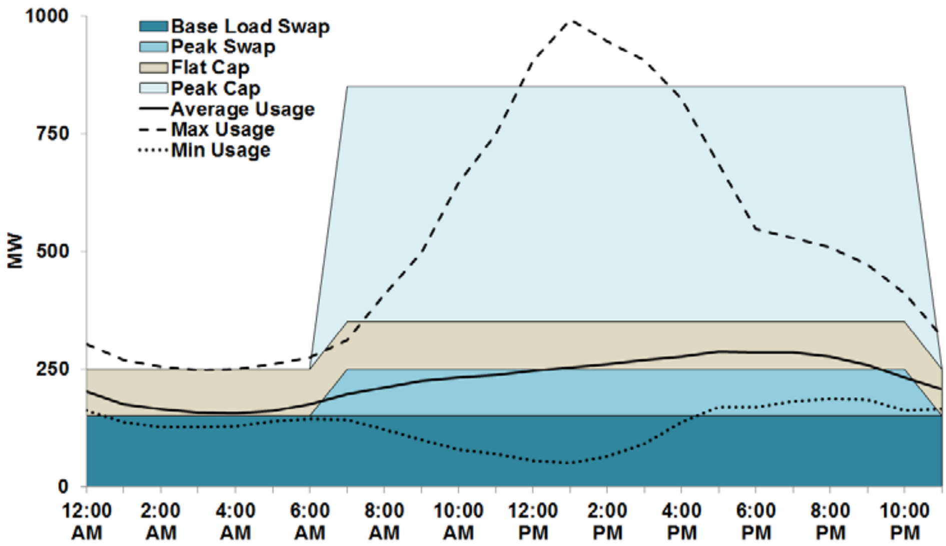
Because spot price outlooks and contract prices change, many retailers require that the hedging cover for a particular year be developed over a number of prior years. For example, 30% may need to be hedged two years before, and 66% one year before.

Due to the mismatch between actual and forecast load (which could be due to unexpected production from an intermittent generation source), as well as the mismatch between block hedging structures and the quantity of power involved, there will be a cost for under- or over-hedging (that is, the risk of under-hedging and the additional cost of over-hedging). This cost of imperfect hedging needs to be borne by either the customer or the retailer.

The ways that retailers use hedging instruments can be illustrated with a simple example.

Figure 34 shows an uncertain demand profile over a day being supplied by a retailer and the contracts being used to hedge wholesale electricity purchases. In this figure, the dotted lines represent the range of electricity demand from customers that the retailer is financially responsible for and the shaded areas represent the coverage provided by the three different hedging instruments.

Figure 34: Hedging a load profile in the NEM



Source: Marsden Jacob, 2017.

We observe:

- a block structure of base-load and peak swaps to approximately cover the average demand shape
- cap contract use to limit the price paid to meet demand considerably higher than the average demand.

Extreme demand exceeding the level of cap contract cover can be managed through appropriate demand management. Other more costly alternatives are to increase the cap contract cover or simply purchase on the spot.

Generator contract sales

Generators are typically the sellers of hedging contracts. While purchasing a hedging contract involves a reduction in risk (the key reason retailers do this), selling a hedging contract involves an increase in risk.

For a generator, selling a swap contract carries the risk that the generator may have an outage when spot prices are high and above the fixed price.[76] For this reason, there is significant risk in stand-alone generators selling swap contracts, and portfolio generators usually do not contract to the full capacity of their portfolio.

Contract premiums

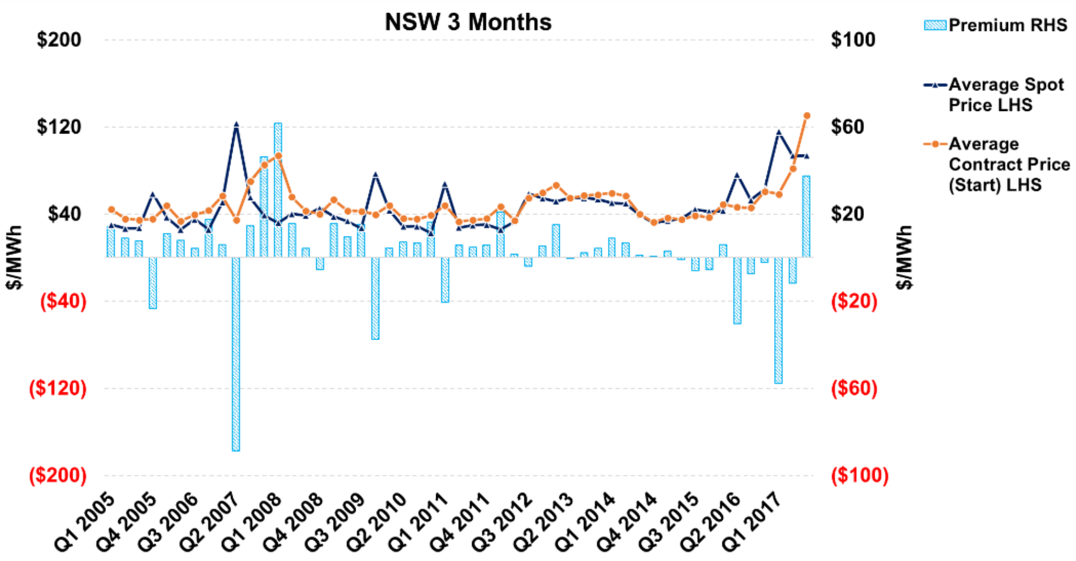
Reviews of historical contract and spot prices have consistently shown that contract prices have for most of the time been priced above spot prices, usually by about $3–4/MWh. This is referred to as the *contract premium*. The reasons for this relate to 'generator outage' risk and the fact that contract prices incorporate an allowance for extreme and unexpected spot prices that may only occur only once every 10 years.

The premium that contract prices have over spot prices and the hedging nature of swap contracts are illustrated in Figure 35, which shows the quarterly price of swap contracts and the corresponding average spot price for that quarter for NSW since 2005.

We observe the following:

- during 'normal' conditions, contract prices were higher than the corresponding spot price
- when spot prices increased late in 2016, contract prices which has been contracted a year before protected or hedged retailers from the price increases
- contract prices responded to changing market conditions and correspondingly increased.

Figure 35: Quarterly swap contract premiums, NSW, 2005 to 2017



Source: Marsden Jacob, 2017.

76 When a generator is offline, it does not receive spot payments.

6.7 Total demand for derivative contracts

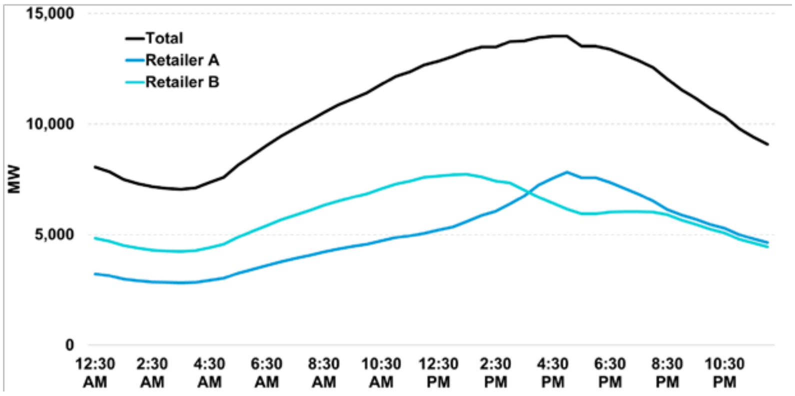
Through the requirements of retailer energy (and large-scale generation certificate) purchase arrangements (that is, spot purchases, physical plant, or contracts), retailers send signals to the market of the type of generation required. An example of this would be a power purchase agreement for a wind generator for both large-scale generation certificates and energy.

The requirements of retailers to manage risk are expressed through their risk management policies.[77] This requires retailers to 'cover' their individual maximum demands in order to limit energy purchase risk.

On a state or total NEM basis, the individual retailers' maximum demands do not always align with the system maximum demand. This is illustrated in Figure 36, in which:

- total market maximum demand: 14,000 MW
- Retailer A's maximum demand: 7,830 MW
- Retailer B's maximum demand: 7,600 MW
- total maximum demand to be covered by the retailers: 15,430 MW.

Figure 36: Individual retailers' demand compared to total system demand (MW)



Source: Marsden Jacob, 2017.

This means that the total demand for contracts directed at managing capacity risk, particularly cap contracts, is greater than demand calculated based on regional maximum demands (which includes the impact of retailers' demand diversity).

The total demand for hedging contracts directly affects the value and economics of providing hedging contracts, whether provided by peaking generation or pumped storage, such as Snowy 2.0.

6.8 Ensuring reliability and security

The NEM has a reliability standard that is expressed in terms of the maximum expected unserved energy, which refers to the amount of energy that is required by customers but cannot be supplied. The Australian

77 As part of prudent management and in meeting the requirements for holding a financial services licence, electricity retailers (and generators) normally have in place robust energy risk management policies that may be reported to a separate board subcommittee. a management committee specifically on energy risk, or both. Risks, as they relate to energy risk, are typically characterised as market, credit, liquidity/funding, operational, legal or regulatory risk.

Energy Market Commission (AEMC) states that:

> *Currently the reliability standard is set as having no more than 0.002% unserved energy. This means that out of 100,000 MWh of demand, no more than 2 MWh of unsupplied electricity should occur over the longer term.*[78]

In the NEM, security is maintained through operating the power system within established *security limits*. This means that, if necessary, customer demand will be shed to maintain the power system in a secure state.

Adequacy of generation is provided through market mechanisms that have spot price levels designed to increase in a manner that would make new-entrant generation to satisfy the reliability standard economic, based on projected development costs. The key settings in the NEM that provide for this are the market price cap and the cumulative price threshold:

- the *market price cap* is the highest level that the spot price can reach (currently $14,200 MWh)
- the *cumulative price threshold* places a limit on the costs payable for wholesale energy purchases over a period due to very high spot prices.

The market price cap and cumulative price threshold are together referred to as the *reliability setting*. The reason for this is that they are set at a level that would theoretically have sufficient generation enter the market such that the level of supply reliability would be at the standard required (unserved energy of 0.002%). The higher the reliability setting, the more revenue generators can make at times when there is a shortage of generation. The AEMC has modelling done every two years to determine what the setting needs to be.

The increase in intermittent generation affects power system reliability, the dynamics of spot price volatility, and the reliability setting needed to have the NEM provide the required reliability level. Without storage, there is likely to be an increase in the requirement for peaking generation and in the need for greater financial incentives to provide it. This would mean a higher market price cap and cumulative price threshold and associated higher risks and customer prices.

78 AEMC 2013, *Fact sheet: the NEM reliability standard*, 2013, www.aemc.gov.au/getattachment/2f4045ef-9e8f-4e57-a79c-c4b7e9946b5d/Fact-sheet-reliability-standard.aspx [8 November 2017].

7. Future NEM reforms: 5-minute pricing

A number of reforms are being proposed for the NEM. These reforms have the potential to affect the value provided by different generator types (including batteries) and the associated development and operational economics.

7.1 Reasons for a move to 5-minute pricing

Five-minute energy settlement involves transacting spot energy sales on a 5-minute basis, rather than averaging six 5-minute spot prices over 30 minutes and applying that rate to (metered) 30-minute energy quantities.

A move to 5-minute energy settlement would be a significant change to the operation of the NEM. This matter has been extensively debated. On 5 September 2017, the AEMC published a draft determination that it be introduced over a three-and-a-half year period. Reasons for the introduction include the need for improved price signals, more efficient generator bidding and more efficient investment in flexible technologies.

The AEMC's Five-minute settlement draft determination: fact sheet states:

- this system has been in place for around 20 years. Different periods for dispatch and settlement were adopted due to limitations in metering and data processing at the time the national electricity market started. Technology is now available which makes 5-minute settlement possible
- the AEMC has made a draft determination to change the time interval for settlement in the wholesale electricity market from 30 minutes to 5 minutes.

The AEMC draft determination also expressed the following:

> *Moving to 5-minute settlement would align the physical electricity system, which matches demand and supply of electricity every 5 minutes, with the price signal provided by the market for that 5-minute period.*

Improved price signals can lead to more efficient bidding and operational decisions by generators, more efficient investment in flexible technologies (such as aggregating distributed storage and new-generation gas peaking plants) and rapid demand response. Over time, this would feed through to lower wholesale costs, which make up around one-third of a typical electricity bill.

The draft determination proposes a transition period of three-and-a-half years to move to 5-minute settlement, which would require major upgrades to IT systems and metering.

This paper note that such a move would also affect the contract market. Under 5-minute settlement, gas-fired peaking generators might not be able to offer the same volume of contracts, or meet their existing contracts with retailers, if they are not able to obtain the same returns at times of high spot prices. The transition period would allow most existing hedging contracts to roll off, while enabling new contracts to accommodate the future implementation of 5-minute settlement.

7.2 Assessed impact on the NEM

The introduction of 5-minute pricing would interact with the following NEM functions:

- energy market price signals (the primary reason for the suggested change)
- the relationship of capacity needed to provide a given amount of energy in a dispatch interval
- the risk in providing derivative contracts, particularly cap contracts
- incentives for non-scheduled generators and demands (another stated reason for the suggested change)
- the quantum of frequency control ancillary services (FCAS) that may need to be procured and the available suppliers of those services
- the settings required for power system reliability and plant response.

The AEMC has indicated that investment in new technologies, such as battery storage, will enable market participants to respond to 5-minute price signals in the future (hence the need for a five-year transition period).

The main impacts of 5-minute pricing that would affect the market benefits provided by Snowy 2.0 are described below.

Energy market price signals

A review of past spot prices shows that most 5-minute dispatch interval price ‘spikes’ have been single (or isolated) 5-minute spikes.[79] Reasons for this include peaking plant response, which generally misses the first 5-minute dispatch interval price spike and captures the second spike (if there is one). The response of peaking plant often results in a potential price spike not occurring in later 5-minute periods of a 30-minute trading interval.

Derivative contract (cap) risk

As discussed in this report, derivative contracts are a basic component of electricity spot markets. It has been understood for many years that the efficient operation of the spot market requires a properly functioning contract market. The key issues are contract liquidity, price transparency and managing market risk (such as spot market price spikes).

The bulk of sold derivative contracts contain risk through coverage by physical peaking plant. Due to the technical characteristics of peaking plant (hydropower, OCGT and so on), the ability of that plant to defend against or manage price risk in 5-minute intervals will decrease for most, if not all, peaking generators in the NEM.

Time to start and generate

The physical coverage of 5-minute price spikes comes from generation already operating (which includes peaking plant) and peaking plant not yet operating. A review by Marsden Jacob of the response rate of such plant showed that plant already operating (at minimum generation levels or more) could generally respond as required, but that peaking plant not operating could not start and ramp in time to commence supply in the first 5-minute dispatch period. This is very different under 30-minute prices, where non-operating peaking plant could substantially capture the first 30-minute period.

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79 Russ Skelton & Associates, *5-minute settlement: assessing the impacts*, report prepared for the Australian Energy Council, March 2017, www.energycouncil.com.au/media/8121/rsa-5-min-settlement-final.pdf [8 November 2017].

The consequences of non-operating plants being unsuitable to capture the first 5-minute price spike, in a market dominated by single 5-minute price events, is that they become unsuitable for managing sold cap contract risk.

Capacity to cover 5-minute energy

The relationship between the capacity (MW) required to provide a particular amount of energy (MWh) is different over a 5-minute period compared to a 30-minute period.

Over a 5-minute period, a generator commencing from zero output is required to linearly ramp to its target level. For example, this implies that to supply an average of 1 MW in a 5-minute period a generator needs to ramp to 2 MW (and thus have 2 MW of capacity). Over a 30-minute period, a peaking generator will reach full capacity in (say) 10 minutes, with the result the plant will have had an average output of 5/6 of a MW over the 30-minute trading interval.

This means that under conditions of increasing demand, a scheduled plant needs more capacity to provide an average capacity level in a 5-minute period as compared to a 30-minute period[80]. A very fast response generator, such as a battery, could overcome this by instantaneously increasing output to the required capacity level (with almost a 1-to-1 relationship between capacity and energy delivered). As a consequence of the almost immediate response by battery technologies (and more rapid response of other fast start plant, such as aero-derivative gas turbines), an increase in the amount of lower regulation services (and potentially other lower FCAS services) will be needed to absorb the excess energy supply.

Cap contract reduction

Given the inability of existing peaking plant to respond to 5-minute prices from a cold start, there would be a vast reduction in the level of cap contracts that can be supported by currently registered generation. In fact, existing plant might not be able to provide any cap contracts unless the operating regime for the plant is altered (for example, to operate at minimum generation).

A conservative estimate of the reduction in cap contracts ignores the energy/capacity issues raised above and is based on the amount of peaking plant typically not operating at times when price spikes may occur (leaving aside that history has shown that this can be at any time).

The estimated requirement to cover load flex (the difference between maximum peak demand and average peak demand) in the mainland NEM is currently over 13,000 MW, and approximately 8,500 MW of peaking plant is needed to cover that load and associated price volatility. It is estimated that, due to the technical capability of peaking plant, the amount of caps available from existing providers under a 5-minute settlement market would decline from the present level by at least 4,000 MW, and most probably substantially more.

This would mean that, without alternative means of covering cap contracts, the suppliers of cap contracts would need to keep plant operating, including peaking plant, more than would have otherwise been the case. With more high-cost gas-fired plant operating under 5-minute dispatch, overall generation costs would be likely to rise, and increased gas use would further limit the availability of gas for other users (such as domestic and industrial users).

Ancillary services

While 5-minute energy settlement periods do not involve intra-5-minute operations, there would nevertheless be a substantial impact on the FCAS markets. This would arise because of:

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80 It is understood that the details of NEM operation under 5 minute pricing have not be fully determined.

- increased uncertainty and error in the 5-minute demand forecasts and lower incentives to linearly ramp within a 5-minute period
- reduced generator capacity available for FCAS duties, due to the need to reserve it for energy market response.

The consequence is that additional plant would be needed, which would reduce the efficiency of both the energy market and FCAS operations.

7.3 Plant development and cap contract pricing

A move to 5-minute pricing will mean that cap contract cover will need to be provided by fast response plant. Examples of such plant are:

- OCGT plant supported by batteries with enough storage to operate until the OCGT plant reaches full generation (about 10 minutes)
- reciprocating gas plant, which has very fast start times suitable for 5-minute pricing.

AGL has announced that reciprocating gas technology will be used for new gas plant in South Australia to replace Torrens Island Power Station.[81] The cost quoted by AGL was $295 million for 210 MW, or $1400/kW, which is higher than the cost of OCGT plant. It is noted that AGL have since delayed the development of this plant.

81 N Hamsen, 'AGL announces plans for new gar-fired power station in South Australia', *ABC News*, 7 June 2017, www.abc.net.au/news/2017-06-07/agl-announces-new-sa-power-station/8596016 [8 November 2017].

8. Generator and retailer economics and increasing intermittent generation

The changing nature of the NEM will affect the dynamics and economics of both generators and retailers. This chapter considers the economics of generators and retailers in the context of the NEM, their respective competitive positions, the criteria for entering the NEM or closing plant, and how generators' and retailers' costs are reflected through spot prices.

'Generator economics' refers to the competitive position of existing generators and generators yet to be developed.

'Retailer economics' refers to the optimal procurement of wholesale energy to supply a defined and variable demand profile within risk limits and satisfy any imposed obligations, such as for environmental protection and reliability.

To be economically dispatched, existing generators need to have short run marginal costs lower than the clearing spot price. To be sustainable, existing generator revenues must exceed the costs that would be saved if the generator were closed. For a new generator to be developed, it must have a return on capital greater than a defined rate.

8.1 Generator costs

As previously described, generator costs consist of:

- capital costs (of construction, including connection to the transmission system, and any fuel assets required, such as pipelines)
- fixed operations and maintenance (FOM) costs, such as the cost of staff, insurance and so on
- variable operations and maintenance (VOM) costs, which are primarily fuel costs and the costs of additional maintenance that results from using a generator.

Based on the cost components, the cost profile of a generator unit is expressed in the following terms:

- Short run marginal cost (SRMC): This is composed of costs that are variable over the short term. For generators, those are fuel costs and variable maintenance costs.
- Mid run marginal cost (MRMC): This is composed of the costs that would be avoided (assuming no contractual obligations) if a generator unit were to shut down. Those include the costs that comprise the SRMC and all fixed operating costs, such as capex, opex, staffing, management, insurance and licence fees.
- Long run marginal cost (LRMC): This is the total cost of a generator over its economic life. It includes all capital costs and all variable costs. This is the cost that needs to be considered in an investment decision.

These costs determine the economics of the entry of a new generator, the closure of an existing one, and how a generator will operate when it is built. These are critical matters in how scheduled generation (new and existing coal, gas and hydro plant) will respond to increasing levels of renewable generation entry.

A new generator is economic if the return on capital exceeds a specified level (or hurdle rate).

For example, for an OCGT plant with a capital cost of $1,000/kW installed, the annualised capital cost is $97/kW/year based on a real WACC of 8% and a 30-year economic life. Expressed on a MWh capability basis, this is $11.1/MWh ($97/kW/year × 1,000 kW/MW ÷ 8,760 hrs/year). Similar calculations for CCGT and back coal generators indicate returns on capital of $14/MWh and $30/MWh, respectively.

The required return on capital is referred to as the *premium* required (note that the term 'premium' is also used in other contexts).

The LRMC for a generator includes capital, fixed operations and variable operations costs. Fixed operations costs plus variable operations cost is defined as the MRMC.

Thus, LRMC ($/MWh) = capital cost ($/MWh) + MRMC ($/MWh).

8.2 Generation investment and closure

The introduction of the NEM removed the planning of generation from the individual states and replaced it with planning subject to commercial considerations, but with the market and the then system operator, NEMMCO,[82] assessing the sufficiency of generation. States could still develop generation (one example being Callide C in Queensland).

As previously noted, the prime signal for the amount and type of new generation in the NEM derives from the requirements of wholesale energy purchasers, particularly retailers. This signal is expressed in the type of electricity supply contracts required, such as base-load (swap contracts) or peaking (cap contracts).

However, spot price opportunities also present signals, as demonstrated by the Millmerran Power Station, which has an SRMC substantially lower than the projected spot price and entered the market with very few supply contracts. New-entry dynamics also apply for vertically integrated entities that undertake to control their supply chains.

Generation entry

Like any capital investment, a generator is economic if the contribution to capital over the life of the generator provides the return required. For a generator, the contribution to capital can be expressed as the present value of the projected revenues less the present value of operating costs. The generator's revenue less variable operating cost is referred to as the operating surplus. The operating surplus is highly dependent on the generator's fuel costs and the profile of spot prices.

Revenue assessments are typically based on projected spot prices and expected plant operation (which provides the spot market revenues) and any premium value associated with the sale of derivative contracts (that matches the operation of the generator).

Because generators cannot be developed quickly, the investment decision usually involves assessments (through due diligence work) of the future operation profile of the generator and future spot and contract

82 The National Electricity Market Management Company (NEMMCO) was the original system and market operator. It was later replaced by the AEMO.

prices, and the spot and contract revenues that the generator will capture.

Before about 2010, conventional thinking was that spot prices would gravitate to LRMC levels as demand increased and that new generation would be required. With demand outlooks showing little or no growth, this paradigm has changed. Scheduled demand is flat, while at the same time intermittent renewable generation is increasing. This is a critical issue in the economics and type of capacity required in the NEM in future.

Generator closure decisions

The economics behind generator closures is that a generator unit should close if the economics of the generator entity is improved by taking the unit out of service. An improvement in economics would occur if the costs saved through closure (termed avoidable costs, which include the SRMC, FOM costs and future capex costs) exceed the future revenues that would be achieved if the plant kept operating. Here we note two issues:

- For entities that have many generators / power stations, closing one of their generators can improve the revenues of the others through the increase in price that accompanies the generator closure.
- Contractual commitments, such as fuel contracts, which have minimum delivery quantities, effectively turn a variable input cost into an unavoidable cost, which effectively lowers the avoidable cost of plant closure.

Leaving aside the matter of contractual commitments, the relative economics of generator closure is not determined by a simple comparison of MRMCs but by comparing forgone revenue to the MRMCs. This recognises that all generators operate in different roles with different capacity factors and therefore have different dispatch weighted prices.

This is illustrated by way of example in the box below, which shows how the comparative economics of different generator units might not align with a simple comparison of MRMCs for four generators.

The economics of existing generators, particularly base-load coal-fired generators, will be critical to the operation of the NEM under increasing levels of renewable generation. The economics and reliability of future NEM operation will require that existing thermal generation can operate economically. This will require an appreciation of economics when such plant needs to modify its operating profile.

Example: generator profitability and MRMC

The table below shows four generators with different capacity factors (CFs), SRMCs, FOM costs and dispatch weighted prices (DWPs).

MRMC ($/MWh) = FOM costs ($/MWh based on 100% capacity factor) / CF + SRMCs ($/MWh).

DWP ($/MWh) = revenue ($) / generation (MWh)

The resulting MRMCs are calculated and compared to the DWPs (both calculated on the same CF).

Generator	CF	SRMC	FOM	MRMC	DWP	Profit
	%	$/MWh	$/MW/year	$/MWh	$/MWh	$/MW
GA	90%	$5	150,000	$24.03	$35	$11
GB	60%	$28	80,000	$40.22	$45	$1.8
GC	65%	$21	100,000	$38.56	$47	$8.5
GC	5%	$60	30,000	$128.49	$110	–$18.5

Source: Marsden Jacob, 2017.

8.3 Dispatchable generation operation under increasing intermittent generation

Increasing intermittent generation will result in dispatchable demand becoming more volatile and uncertain. This will affect the operation of dispatchable generation and (without storage) will require additional flexible peaking generation or increased interconnection to provide the required generation response.

This is a complex dynamic, as it involves many issues, which include:

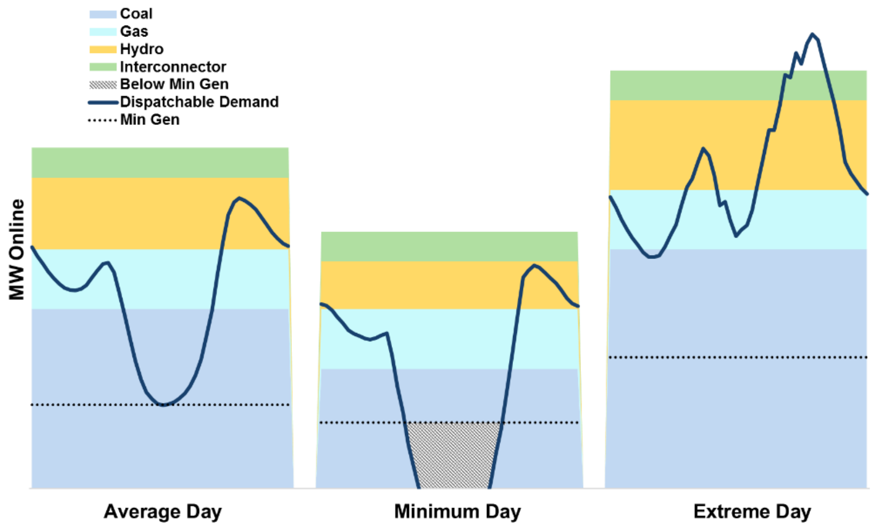
- increasing intermittent generation, requiring dispatchable generation to change operation:
  - base-load generation operates less (this can be thought of as moving to an intermediate role)
  - intermediate and peaking generation responds to greater uncertainty in same-day and next-day requirements, possibly requiring the maintenance of additional operating reserves (that is, operating generators at part load)
  - both of which are moderated somewhat by interconnection and diversity between regions of demand and intermittent generation operation
- increased financial stress on base-load power stations as a result of reduced operation and or increased cycling:
  - potential closure of coal-fired power stations permanently or for certain periods in the year
- required new capacity:
  - very low maximum demand growth, so that without any generator closures there should be sufficient capacity to meet high demands
  - increasing intermittent generation provides some capacity support, but reduces the economics of dispatchable generators
  - the firmness of capacity from other states across interconnectors is likely to reduce
- potential constraints on intermittent generation:
  - potential need to reduce intermittent generation to avoid thermal generation output being below minimum generation levels
  - closing thermal generation lowers the level of minimum generation, providing for more unconstrained intermittent generation.

With the maximum scheduled demand projected to have only a small amount of growth and with dispatchable demand decreasing in future, the key change will be generator closures (most likely of coal-fired generators, because of their age and economics). While such closures would reduce the level of dispatchable capacity to meet high demand, they would reduce potential constraints on intermittent generation associated with coal plant’s minimum generation levels and ramp rates.

These issues are illustrated in Figure 37, which shows, over a day, three different situations involving dispatchable demand (i.e. scheduled demand less intermittent generation) and the amount of dispatchable capacity available:

- Left: Average amount of intermittent generation and average amount of dispatchable generation operating. There is sufficient capacity and no constraints.
- Middle: High amount of intermittent generation and less dispatchable generation operating. There is sufficient capacity but a high level of constraints on intermittent generation.
- Right: Low amount of intermittent generation and a higher amount of dispatchable generation operating. There is insufficient capacity to meet demand but no minimum generation constraints.

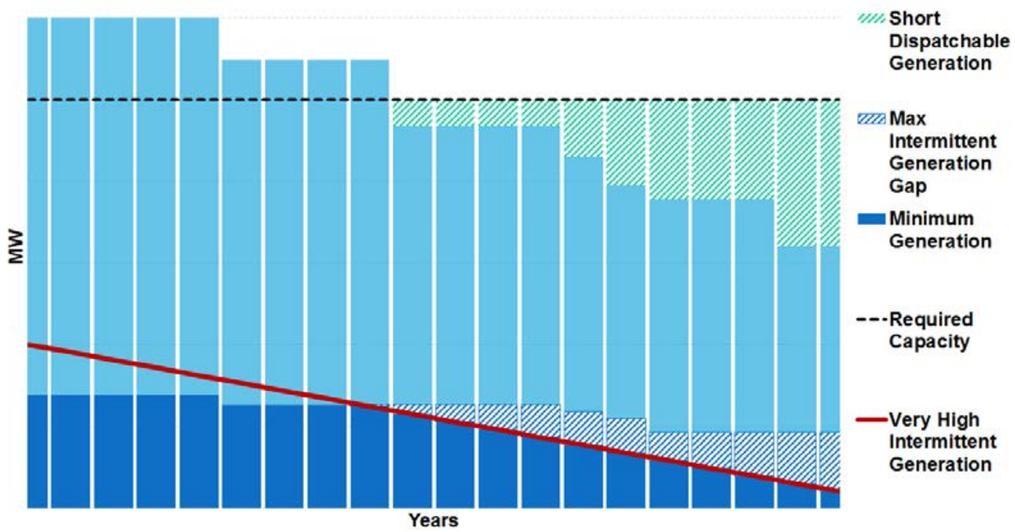
Figure 37: Balance between thermal minimum generation level levels and capacity shortage (MW)



Source: Marsden Jacob, 2017.

The balance between minimum generation levels and generation capacity needs moving forward is illustrated in Figure 38, which shows, as coal-fired generation is closed, a decreasing minimum generation level and an increasing capacity shortage.

Figure 38: Changing balance in the future (MW)



Source: Marsden Jacob, 2017.

Looking forward in relation the NEM:

- There will be a need for dispatchable capacity to address the closure of Hazelwood (closed March 2017) and Liddell power stations (announced by AGL to close in 2022). As the level of intermittent generation is not large, and because of constraints on such generation due to thermal generation, minimum generation levels are likely to be low.
- Addition coal generator closures will reduce the impact of minimum generation constraints on intermittent generation as the level of intermittent generation increases. However, the 'flip side' is a deficit in required dispatchable capacity that would need to be provided by new dispatchable capacity (thermal generation, demand management or storage). Storage would allow the economic development of further renewable generation.

- In the longer term, the amount of renewable generation will have significant impact on base-load generation and the requirement for dispatchable peaking capacity.

The factors that would influence the economics of future operation include:

- the ability of coal-fired generation to reduce output when dispatchable demand is very low
- the economics of having coal-fired generation operate at moderate to low capacity factors and the operating costs of more flexible operation
- the ability to have surplus generation that can increase at short notice when dispatchable demand is very high, which may mean having gas-fired plant operating when it is not needed
- reducing intermittent generation when dispatchable generation cannot respond or system security is an issue (for example, reducing intermittent generation to avoid coal-fired generation operating below minimum generation levels)
- the ways intermittent generation from a neighbouring region (such as Queensland in relation to NSW) affects generation operations of the other regions.

These issues are already evident in South Australia, which has a large amount of intermittent generation.

Noting the above, there is a question of how dispatchable generation would or should operate to meet the projected profile of dispatchable demand. There are options in the operation of dispatchable plant, as it can be operated to provide for intermittent generation to operate without constraint, or to provide for intermittent generation to be constrained to avoid over-reducing thermal generation (but with consequences for replacement generation costs and increased carbon emissions).

How dispatchable generation operates with high levels of intermittent generation will be determined by cost: commitment/de-commitment costs, fuel costs (most notably coal and gas) and the value placed on carbon abatement.

An operating regime that would involve minimum offloading of intermittent generation would have the value of carbon abatement and fuel costs higher than the associated costs of coal-fired plant operations involving regular de-commitment and cycling. Such a regime would have a greater need to operate flexible gas-fired generation.

The counter would be the case for an operating regime that has a higher level of intermittent generation offloading.

8.4 Firming capacity costs

Increasing intermittent generation in a retailer's portfolio will require supporting capacity to satisfy risk limits. Such capacity may be provided physically by retailers developing peaking plant, storage, or both, contracting for products such as cap contracts, or by both methods. This need will be exacerbated by the closure and any changed operation of coal-fired generation.

This has been expressed as *firming intermittent generation*. A move to 5-minute pricing will also have risk implications for retailers.

Changes to risk associated with increased intermittent generation would translate to additional contract cover, while risk associated with 5-minute pricing would require plant or contracts that provide the necessary cover.

Approaches to firming capacity

There are two approaches to firming the generation of intermittent generation: support it with firming generation, such as OCGT plant, or support it with storage.

Open-cycle gas turbine plant

OCGT plant provides continuous capacity, with no limitations (other than fuel supply and outages) on the duration for which the capacity can be supplied. The advantage of this is that it allows cap contracts that include coverage against continuous days of low intermittent generation to be sold. The disadvantage is that that low-value excess intermittent energy cannot be 'moved' to a time of higher value. In essence, intermittent generation is providing energy to reduce the fuel costs of dispatchable plant and a small amount of capacity.

Storage

Storage provides:

- an increase in the value of intermittent generation (by allocating the energy produced by intermittent sources to periods of the highest value)
- dispatchable capacity.

For a given MW rating, the level of storage influences the sustainability and thus the reliability of the dispatchable capacity provided by the storage.

Relative costs of providing firming capacity

Two examples of the cost of providing firming capacity are presented in this section: for battery systems and for OCGT plant. The details of the calculation are given in Appendix 6.

Battery systems

To assess the costs, we made a calculation on the basis of matching a battery system to a solar installation that provides (on average) 4 MWh of energy per day. Given that a battery can have different storage levels, we considered three cases:

- Case 1: The battery has a level of storage equal to the amount that the solar facility produces in a day. The MW capacity of the battery is such that, fully charged and discharging at maximum capacity, it would operate for 4 hours.
- Case 2: Storage is increased to 8 hours and the capacity is unchanged.
- Case 3: Storage is increased to 12 hours and the capacity is unchanged.

The costs associated with storage to firm capacity are shown in Table 11; they are substantial.

These cases represent an increasing level of firmness, as increased storage allows solar energy produced in one day to be used in subsequent days. The value of this additional storage is a separate issue.

Table 11: Costs of 4 MWh per day solar plant plus storage ($/MWh)

	No battery	Battery: 1 MW, storage as specified		
		4 MWh	8 MWh	12 MWh
2018	$64	$326	$528	$730
2032	$35	$218	$345	$473
2040	$33	$207	$328	$449

Source: Marsden Jacob, 2017.

Gas-fired plant

Gas-fired generation provides a firming service very different from that provided by storage. Firming gas-fired generation can be considered as providing mainly capacity and a reduced amount of capacity.

The cost of firming needs to include the requirement to operate plant (particularly CCGT plant) that can take several hours to start. Accounting for those costs, the firming costs are assessed to be in the order of (gas fired generations are projected to remain constant in real term):

- CCGT: $240/MWh
- OCGT: $200/MWh.

A further difference between gas-fired plant and storage in firming intermittent generation is that gas-fired plant has associated carbon emissions (which are relatively high for OCGT plant).

PART D: Intermittent and dispatchable generation outlooks

The key factors and uncertainties influencing the NEM and the economics of a development such as Snowy 2.0 are demand growth, the development of renewable generation (through policy or economics), closures of existing generators (particularly coal-fired plant), and the costs of coal and gas for existing and potential new power plants.

This section presents outlooks for demand, renewable generation development, coal-fired plant closures and fuel costs. Those outlooks are the basis for the NEM outlook with and without Snowy 2.0 and our assessment of the impacts that Snowy 2.0 would provide.

Because of the uncertainty (due to energy policy, future costs, or both) in the quantum of renewable generation to be developed, Marsden Jacob developed two scenarios: LRET+VRET and LT Commitment.

A key component of this section is the introduction and presentation of the demand quantity and profile to be supplied by dispatchable generation (that is, scheduled demand less renewable generation), which has been termed *dispatchable demand*.

9. Electricity demand outlook

This chapter presents the outlook for demand on state-wide and NEM-wide bases. The AEMO publishes electricity demand forecasts for the NEM (the annual energy to be supplied and the winter and summer maximum demands). Future demand is a key issue for the future operation of the NEM and the economics of both scheduled generators and large-scale renewable generation.

The profile of future demand, and the influence that rooftop solar has and will continue to have on reducing demand in the middle of the day, are also important to generation economics.

This outlook and the outlooks for intermittent generation and dispatchable generation in the following two chapters are the key inputs to the economics and future operation of the NEM.

9.1 Projection of future demand levels

As discussed in Section 3.3, in the NEM, scheduled demand is that electricity to be supplied by dispatchable generators[83] and large-scale intermittent generators.[84] It is given by 30-minute (or 5-minute) MW (or MWh) levels on a state-by-state basis.

The key factors that determine future demands are as follows:

- economic growth and the increase (or decrease) in electricity used: The key sectors of electricity use are residential, commercial, manufacturing and large industrial
- the development of rooftop PV, which is 'behind the meter': This results in scheduled demand decreasing during the day as the output from the rooftop PV increases. This is referred to as the 'duck curve'. As the amount of rooftop PV increases each year, the 'dip' in scheduled demand increases
- weather: Very hot or very cold conditions result in high demand for air-conditioning or heating. This can result in days of very high demand
- day type: Weekdays have higher demand than weekends or public holidays
- seasons: The profile of demand changes with the season due to weather and varying hours of sunlight.

Forecasts of scheduled demand are most often described by two metrics (on either a sent-out or an at-generator basis) over the outlook period:

- the annual energy (GWh) required to be supplied each year
- the maximum demand (MW) that can occur over each year.

Each year, the AEMO produces electricity demand forecasts as part of its *National electricity forecasting report* process. The results are annual energy and annual maximum demand projections on state-by-state and total

83 Dispatchable generators are referred to as 'scheduled' generators.

84 Intermittent generators are referred to as 'semi-scheduled' generators.

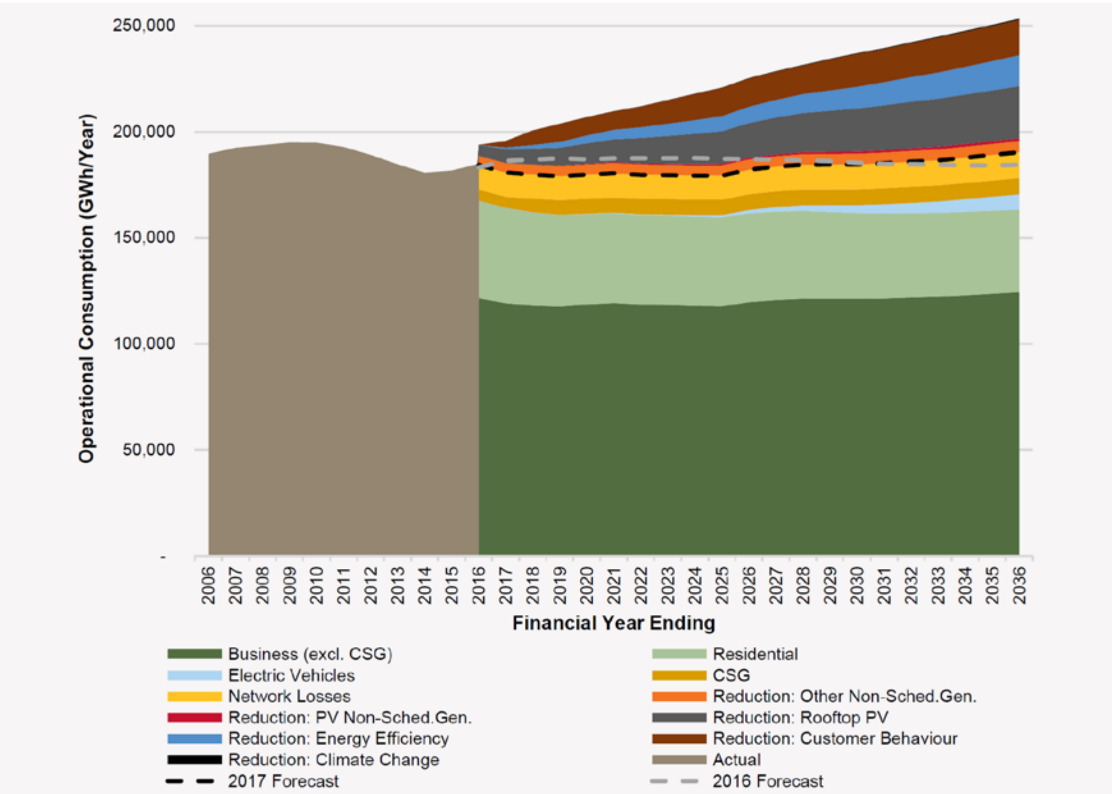
NEM basis.

9.2 Annual energy forecast

Figure 39 is a graphical presentation of the AEMO's annual energy forecasts published in June 2017. It shows the AEMO's most likely scenario (referred to as the 'neutral' scenario) and the components that make up that demand outlook.

The important projection is given by the dotted lines, which show scheduled demand (labelled operational consumption). The outlook for scheduled demand is very flat (slightly lower than the 2016 projection until about 2030). The main reasons for this are reduced electricity use by consumers, growth in rooftop PV and increasing energy efficiency.

Figure 39: AEMO projection of total NEM annual energy, 2016 to 2036 (GWh/year)



Note: the liquefied natural gas (LNG) demand sector in the 2016 NEFR is now referred to as coal seam gas (CSG) and is covering electricity consumption associated with extraction and processing of CSG for both export and domestic markets.

Source: AEMO 2017 National Electricity Forecasting Report.

9.3 Maximum demand forecast

Table 12: is a tabular presentation of the AEMO annual energy forecasts published in June 2017. It shows the AEMO's most likely scenario (the 'neutral' scenario) for summer and winter in the forecast years.

As observed, there is a small increase in maximum demand in all states except South Australia, and NSW moves to having maximum demand occur in the winter period.

Table 12: AEMO projection of maximum demand (MW)

Year	NSW		QLD		SA		TAS		VIC	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2016-17	14,111	13,071	9,355	8,314	3,116	2,732	1,417	1,769	9,493	7,797
2021-22	13,963	13,216	9,606	8,573	3,035	2,726	1,429	1,808	9,403	7,895
2026-27	14,678	14,103	10,074	9,104	3,048	2,825	1,459	1,863	9,395	8,028
2036-37	15,276	15,561	10,021	9,574	3,112	3,003	1,537	1,958	9,758	8,811

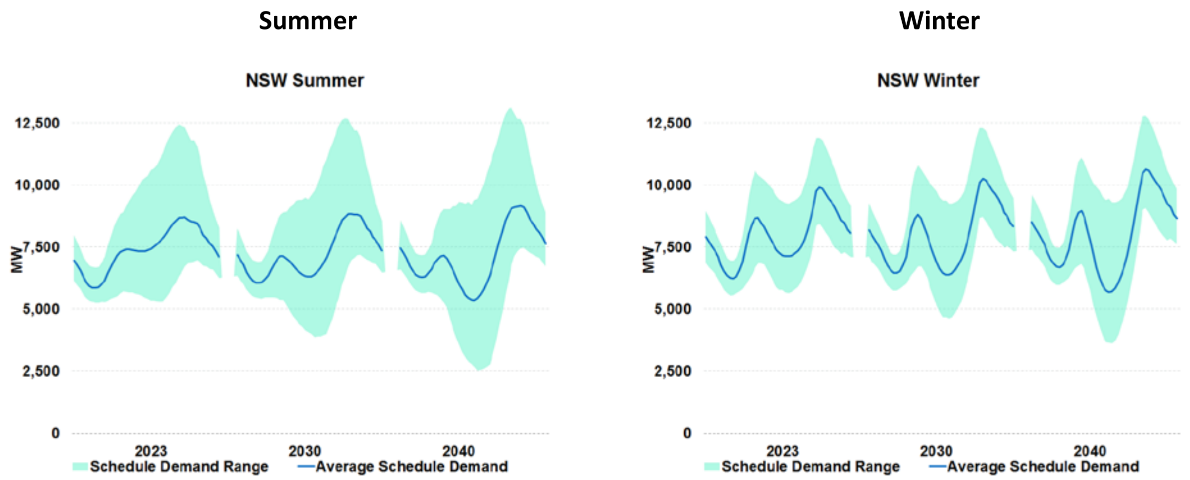
Source: AEMO 2017.

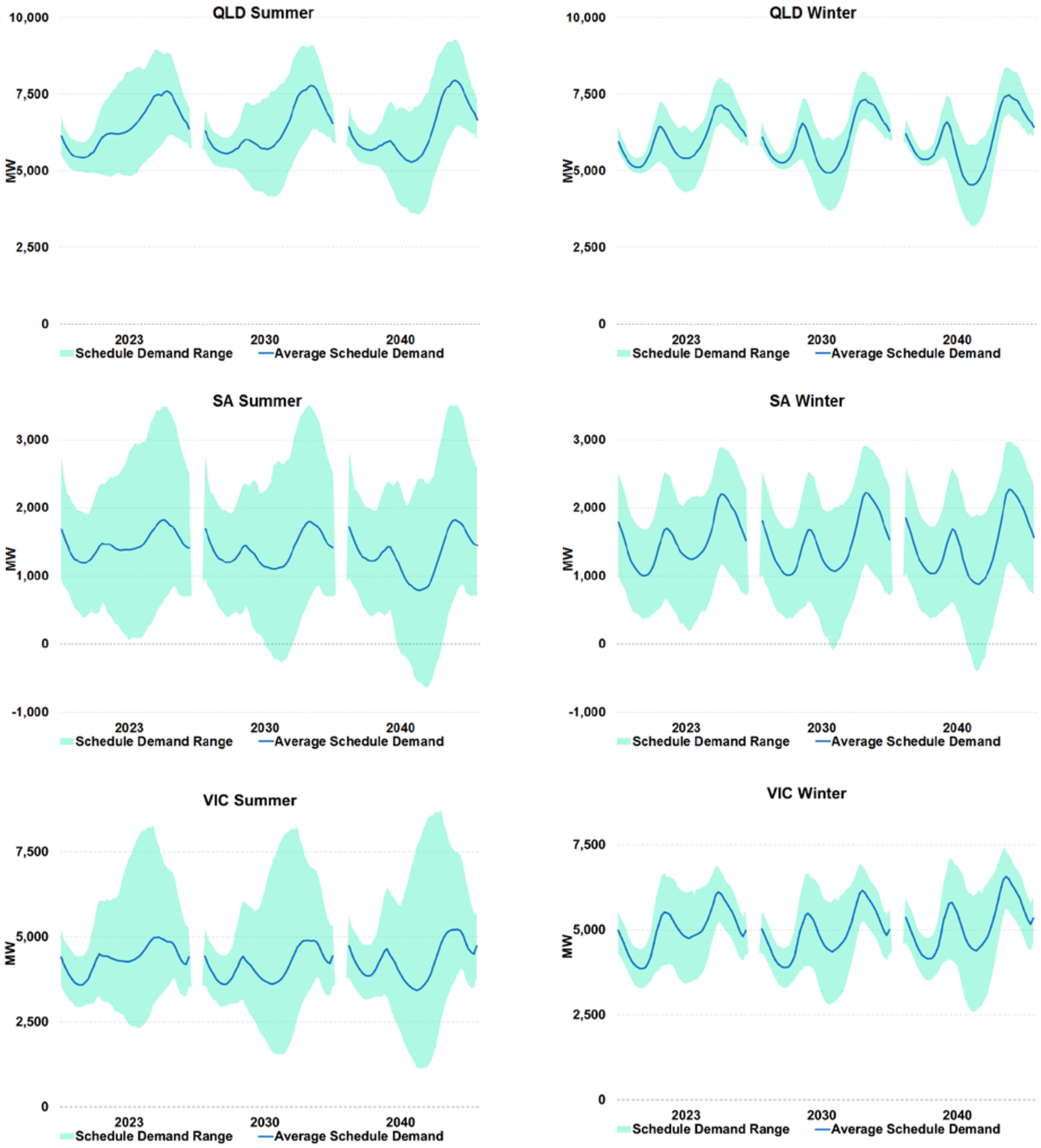
9.4 Future demand variability and shape

Energy and maximum demand indices do not describe the changing shape of scheduled demand in the future. This is most important to the future operation and economics of the system, particularly the influence rooftop PV will have by reducing scheduled demand in the middle of each day.

Figure 40 shows the projected profile and variability of scheduled demand for each state for the sample years shown. The outlook is based on the AEMO's demand projections, rooftop PV projections and electric vehicle projections.

Figure 40: Outlook for the profile and variability of scheduled demand (MW)





Source: Marsden Jacob, 2017.

10. Renewable generation development

A key issue in the future operation of the NEM is the amount of renewable generation that will be developed. That development will be driven by environmental policy, energy policy, economics and preferences. There is uncertainty in all of those factors, rendering the level of renewable generation development uncertain.

Based on the two outlooks of renewable generation development, we describe the resulting demand profile to be supplied by dispatchable generation (that is, dispatchable demand).

To put these matters into context, we also describe the resulting generation mix for the two outlooks.

The outlook on the amount and timing of renewable (intermittent) generation development in the NEM is uncertain. Factors that will influence that development include state and federal energy and environmental policies; the relative costs of renewable generation and storage; economic growth; and consumers' preferences.

The amount of renewable generation will influence the operation of the NEM, the economics of coal-fired (and gas-fired) generation, and the value provided by storage, particular Snowy 2.0.

This chapter describes potential renewable generation development based on announced policies, long-term abatement commitments and economics. The range is defined by two scenarios of renewable generation development, 'LRET+VRET' and 'LT Commitment'.

The renewable generation development scenarios are used in subsequent chapters to assess the impact on the NEM and the economic and price-reducing value that would be provided by Snowy 2.0.

10.1 Level of renewable generation development

Renewable generation policy

The announced policies and targets by government (federal and state) are summarised in Table 13.

Table 13: Proposed federal and state-based renewable energy schemes

Federal/state scheme	Energy target (GWh)	Investment required (in excess of the LRET) (MW)
Federal—LRET	33,000 GWh by 2020	
Federal—National Energy Guarantee	Unknown	Unknown
Queensland—QRET	50% by 2030	'Floating' target of between 4,000 MW to 5,500 MW by 2030[a]. Not legislated.
NSW	–	LRET only.
Victoria—RET	25% by 2020 40% by 2025	Auction scheme that has been legislated [b]: ▪ additional 3,400 MW by 2025 ▪ additional 5,150 MW by 2030.
South Australia	50% by 2025	Aspirational only, but to be achieved through the RET/LRET. Will be (closely) achieved through the LRET.
Tasmania	–	LRET only.

a Queensland Renewable Energy Panel 2016 b Victorian Government Energy Auction Scheme consultation paper 2017

Sources: Marsden Jacob 2017

In relation to Table 13, we note the following:

- The state-based targets are a response to the federal LRET scheme not providing for continuing renewable generation development after 2020:
  - Victoria announced on 23 August 2017 that it would legislate a 40% renewable energy target by 2025.
  - Queensland has not yet legislated a state base target and has not indicated when that might occur. However the state government has been supporting substantial investments in renewable generation.
  - The South Australian targets have largely been met through the LRET as a result of South Australia being a preferred location for wind generation.
- The federal government has proposed that a policy known as the National Energy Guarantee be supported and developed. If federal policy provides for continuing renewable generation development, then the state schemes may be terminated (as has occurred in the past).

Announced renewable generation projects

Table 14 lists renewable projects that have been signalled for development:

- The volume of renewable projects either committed to or intended to be developed is more than that required to satisfy the LRET. If all of this renewable generation entered under the LRET, then the LRET would be oversupplied and large-scale generation certificate prices would be expected to respond accordingly.
- Small-scale renewable generation development makes up a significant proportion of the total amount of signalled renewable generation development.

Table 14: Renewable projects intended to be developed (MW)

	Large-scale wind	Large-scale solar	Distributed solar
Queensland	715	1,084	3,250
NSW	1,071	201	2,881
Victoria	981	20	2,053
South Australia	739	320	1,275
Tasmania	100	0	186

Sources: Marsden Jacob; AEMO, National electricity forecasting report, 2017.

For the purposes of this report, the precise (state or federal) policies adopted are not important. What is important and relevant to the future development of the NEM and how generators operate in the NEM is the amount and type of renewable generation that is developed.

Renewable generation development scenarios

From the above information, we developed an 'LRET+VRET' and a 'LT Commitment' scenario based on the following being satisfied (note that satisfying one criterion may satisfy another):

Assumptions common to the LRET+VRET and LT Commitment scenarios:

- Additional large-scale renewable generation is developed to satisfy the LRET.
  - Rooftop PV development is as given by the AEMO projection (AEMO, *National electricity forecasting report,* 2017, 'neutral' projection).
  - The profile of renewable generation development does not exceed the capacity of known projects over the period from 2017 to 2021.
  - The percentage of renewable generation expressed through legislated state policy objectives would be met. This is the VRET: 40% by 2025 and 50% by 2030.
  - Renewable generation enters (as does non-renewable generation) when economic.
- LRET+VRET renewable development scenario only:
  - After 2030, new renewable generation enters only if economic.
- LT Commitment renewable development scenario only:
  - NSW has a level of renewable generation development equal to a 10% growth in renewable generation in that over the period from 2021 to 2030.
  - Queensland achieves a 50% level of renewable generation by 2030.
  - After 2030, the renewables development profile is such that the NEM moves in an approximately linear fashion to 60% supply by renewables by 2040 (that is, over the period from 2030 to 2040). By 2040, the installation of renewables is evenly spread across the regions, unless a region is over the 60% level of renewable generation. This is consistent with a long-term target of 80% by 2050.
  - The economic barriers to such a profile would be addressed through policy.

Table 15 summarises the scenarios.

Figure 41 shows the profile of renewable generation development by year and type over the period from 2020 to 2040. The values of large- and small-scale renewable generation that comprise these scenarios are given in Appendix 5.

Table 15: LRET+VRET and LT Commitment renewable generation development scenarios

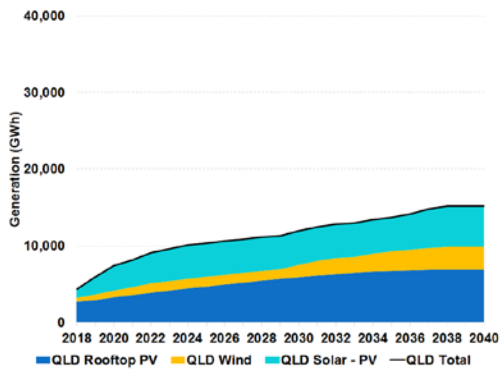
	LRET+VRET	LT Commitment
To 2020	LRET met	LRET met
2020 to 2030	VRET met	VRET met
	–	10% growth in NSW renewable generation
	Economic renewable enters	Economic renewable enters
2030 to 2040	Only renewable generation that is economic enters	Linear increase in renewable generation to a 60% target by 2040.
2040 to 2050	Only renewable generation that is economic enters	Continued development to achieve an 80% level by 2050
	Only renewable generation that is economic enters	Continued development to achieve an 80% level by 2050

The scenarios represent potential ranges of renewable generation development, and no likelihood is assigned in either one.

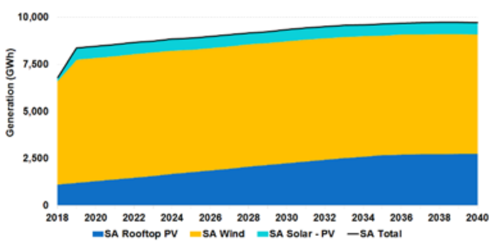
Figure 41: Renewable generation development scenarios, by region (GWh/year)

LRET+VRET, Without SNOWY 2.0

Queensland installed capacity (MW)

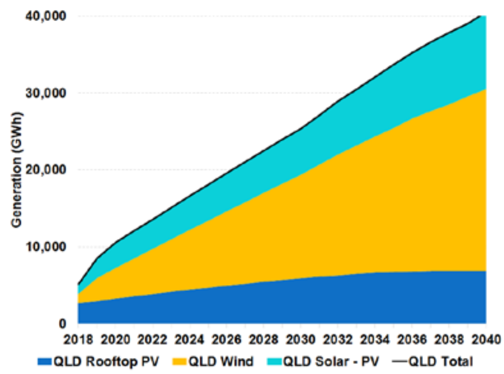


South Australia installed capacity (MW)

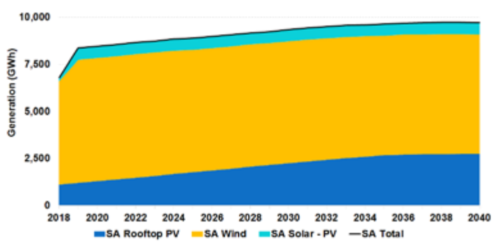


LT Commitment

Queensland generation (MW)

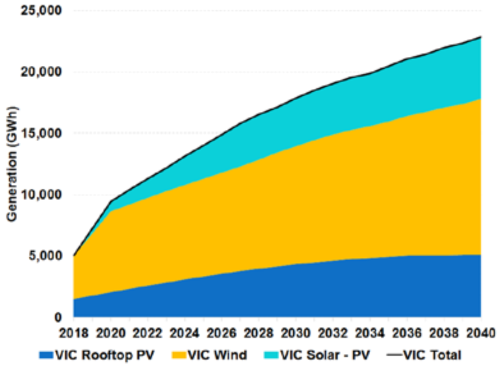


South Australia generation (MW)

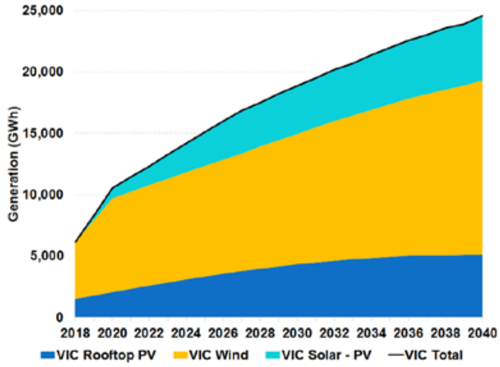


LRET+VRET, Without SNOWY 2.0	LT Commitment

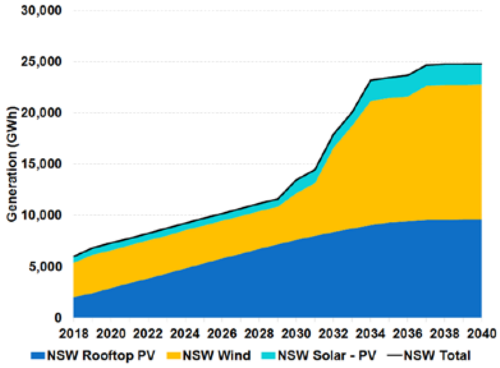
Victoria installed capacity (MW)



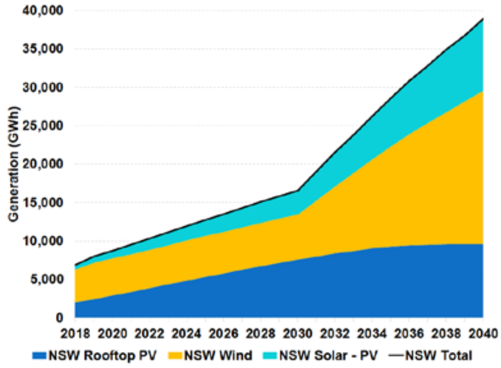
Victoria generation (MW)



NSW installed capacity (MW)



NSW generation (MW)



Source: Marsden Jacob, 2017.

10.2 Dispatchable demand outlook

As discussed above, the economics of dispatchable generation (in the presence of increasing renewable generation) is central to the reliability of electricity supply and to wholesale energy price outcomes. This reflects the following factors:

- Renewable plant will operate (at the level dictated by prevailing wind and solar) once developed, unless financially incentivised to do so (through negative spot prices or particular contract terms) or directed to reduce output by the AEMO (associated with semi-scheduled generation).
- It is dispatchable plant that responds to matching supply and demand and to prices that establish the energy spot price every five minutes.
- Dispatchable plant may close if it cannot operate economically.

A key market outcome that influences the economics of existing and new dispatchable generation, such as coal- and gas-fired generation, is what has been referred to as *dispatchable demand*. This has been defined as scheduled demand less total renewable generation, and is the demand to be supplied by dispatchable generation.

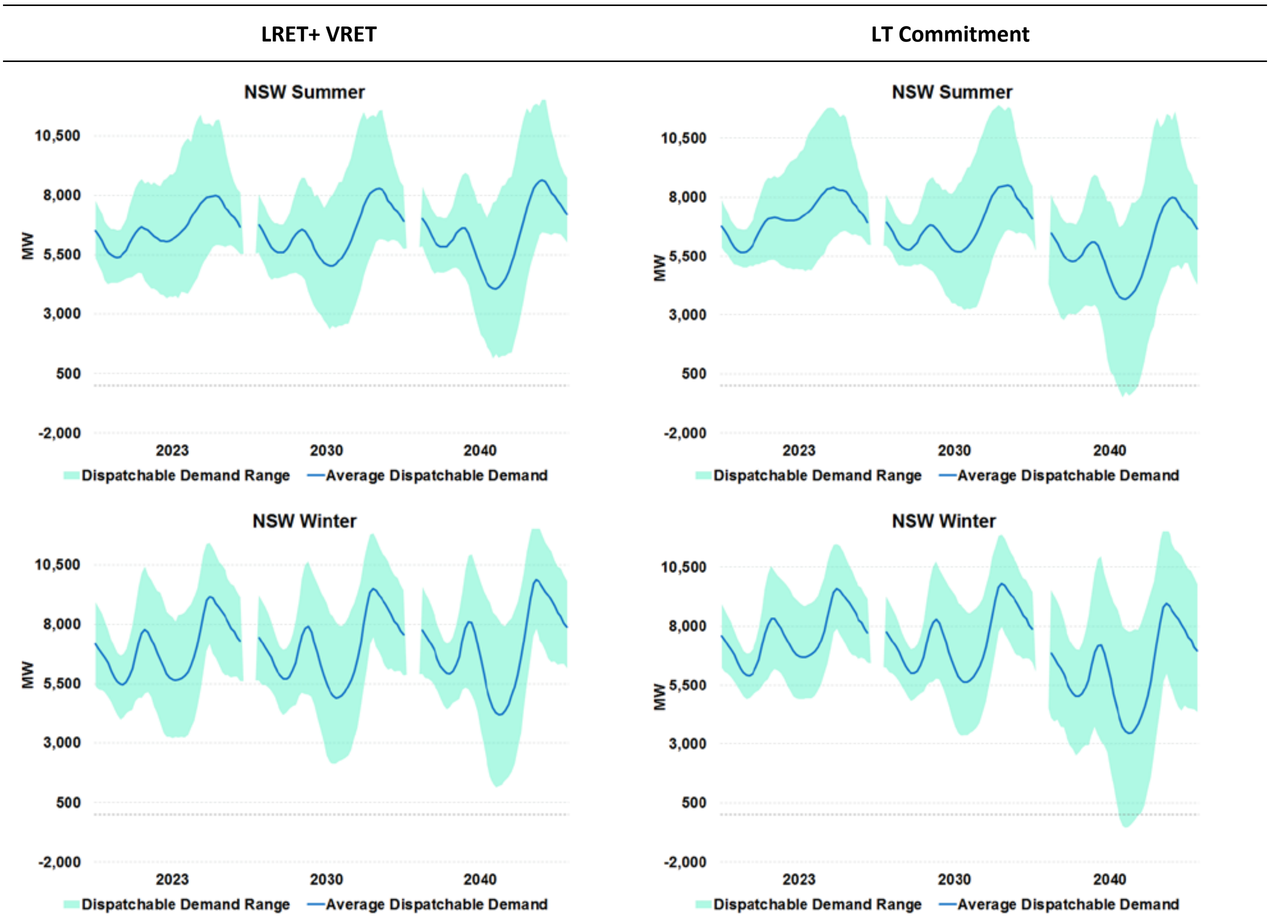
Based on the two renewable generation development scenarios developed in the previous section (LRET+VRET and LT Commitment), Figure 42 shows the profile of dispatchable demand for each for the summer period in each of the years 2023, 2030 and 2040 for each of the NEM states and for the summer and winter periods. For each year, the profile is shown as the average (the solid blue line) and as the variation that can occur (the light blue shaded area). The intention is to show this profile and its variability on a daily basis.

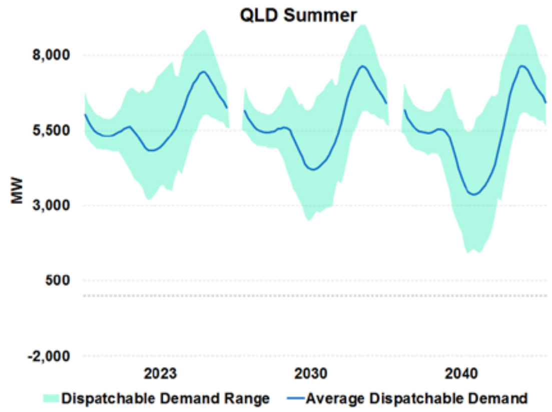
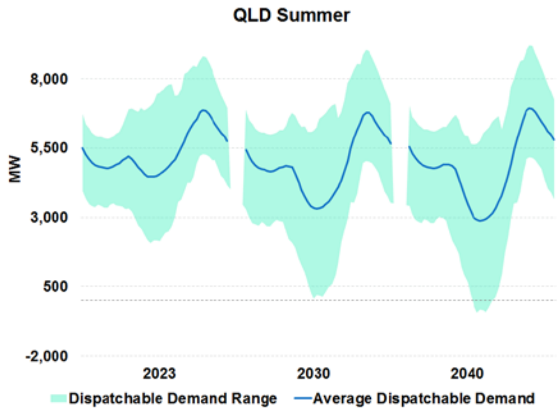
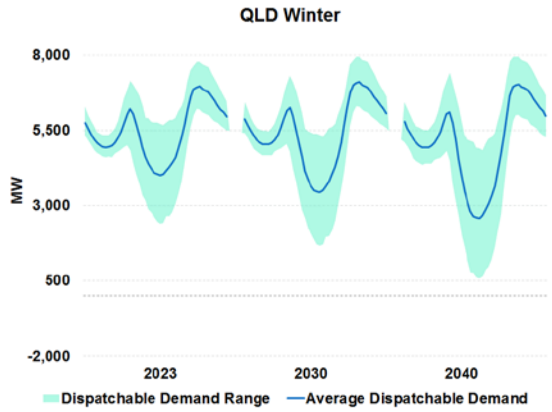
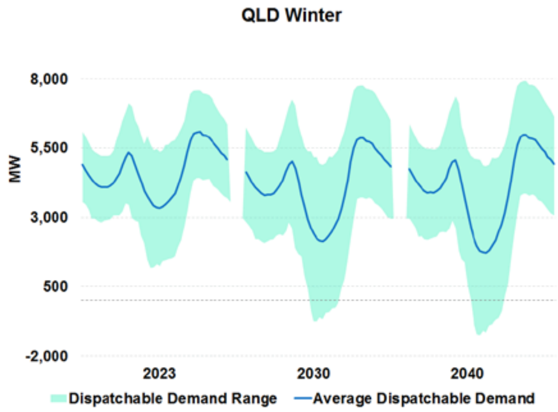
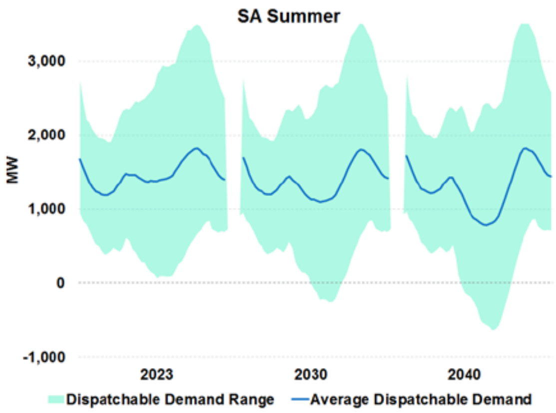
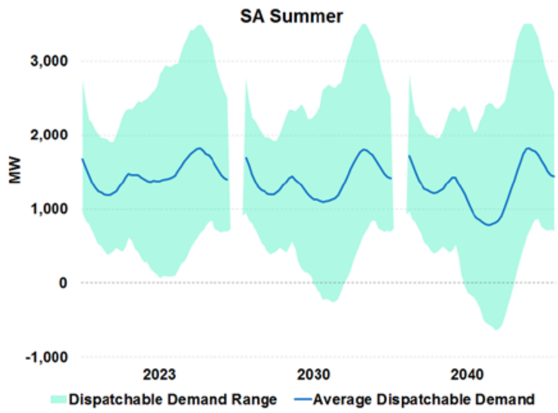
The variability of dispatchable demand can be thought of as schedule demand variability plus intermittent generation variability.

Particular observations from these outlooks for dispatchable demand are as follows:

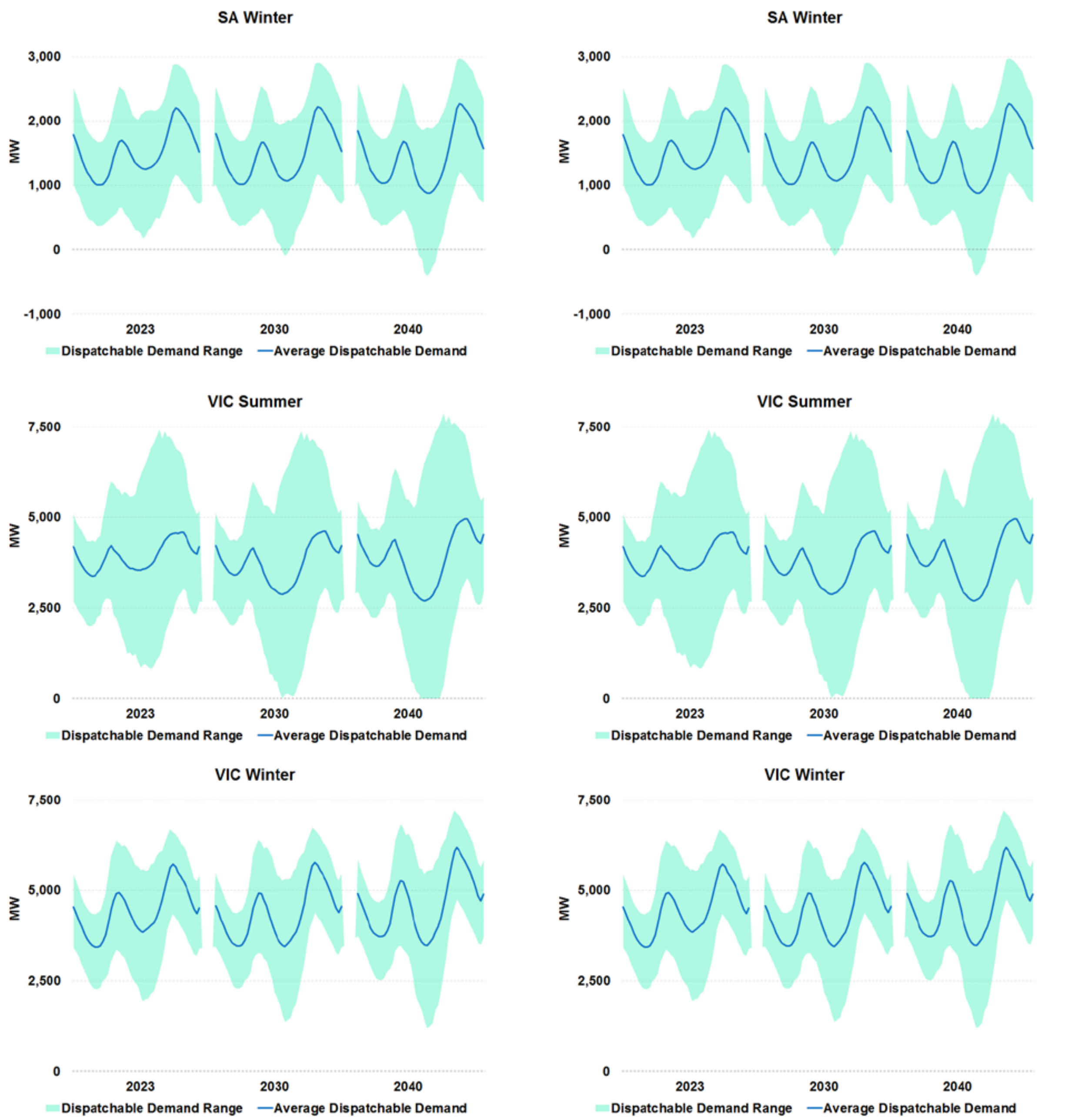
- In the past (that is, when there was little or no intermittent generation), the variation in demand to be supplied by dispatchable generation has been on the 'high' generation requirement risk associated with severe weather conditions. The variation in demand to be supplied by dispatchable generation is moving to both 'low' and 'high' generation requirement risk.
- The high renewable target and the economics of solar generation in Queensland produce an outlook of days when dispatchable demand is below zero.
- NSW is the least affected due to the absence of any policy for renewable generation development after 2020. However, even the moderate assumption of additional renewable generation after 2020 produces days when NSW dispatchable demand can reach very low levels, imposing high costs and creating security issues.
- Victoria has a similar outlook to Queensland; very high variation in dispatchable demand is projected by 2030.
- South Australia rooftop PV projected to continue to increase

Figure 42: Impact of the 'duck curve' on future demand, 2023, 2030 and 2040 (MW)



LRET+ VRET	LT Commitment
	
	
	

LRET+ VRET	LT Commitment



Source: Marsden Jacob, 2017.

10.3 The impact of renewable generation development on existing generation

In Chapter 2 of this report, Figure 4 shows an example of the weekly pattern of generation that is currently typical of the NEM (the first week of August 2017). This is shown on an individual state basis and for the NEM as a whole.

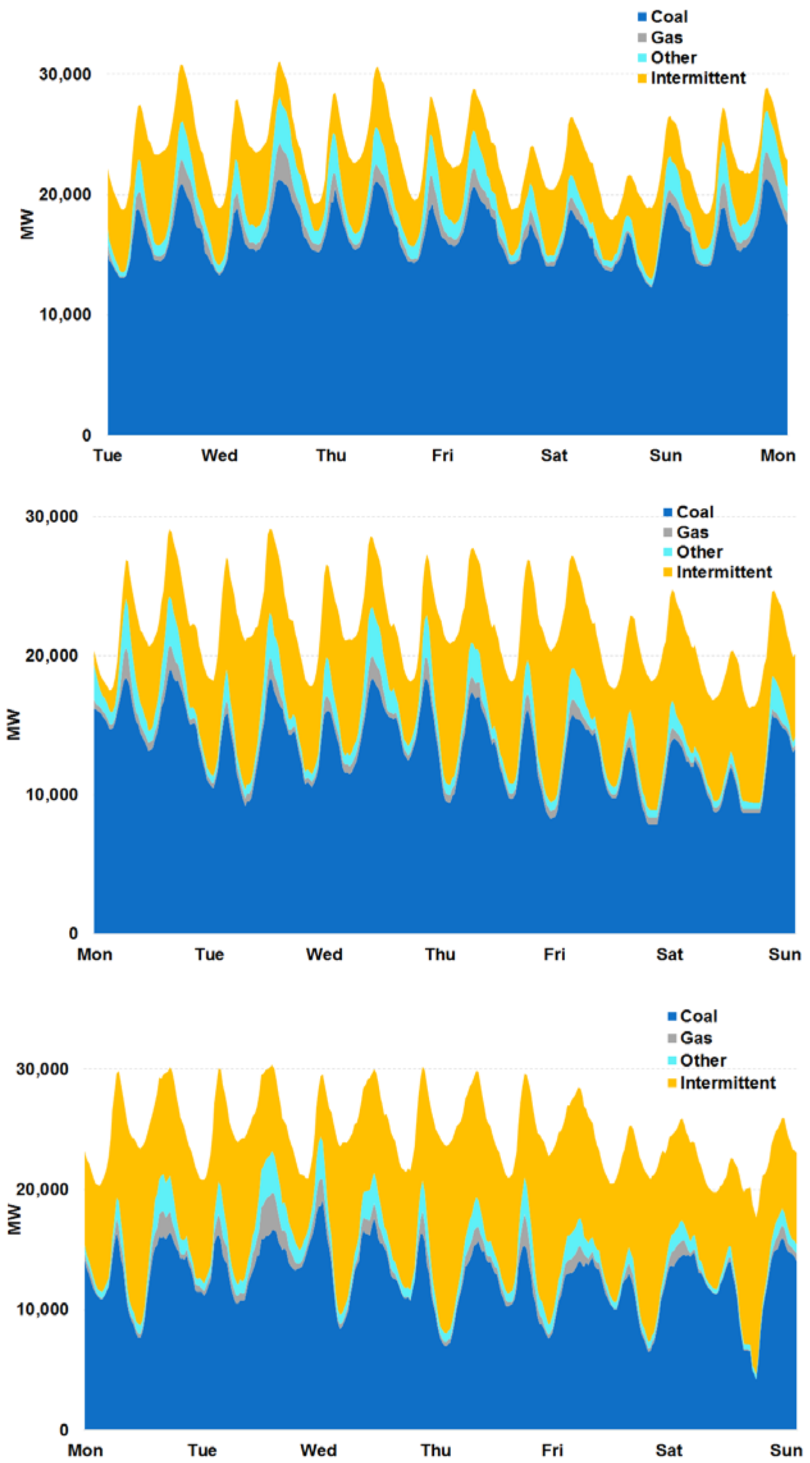
In the same manner, Figure 43 shows the same graph but for a sample of 'typical weeks' and 'extreme weeks' for the period from 2020 to 2040 for the LT Commitment scenario (the year, type of week and scenario are labelled). The yellow area is the output of large-scale intermittent generation.

The impost of renewable generation on non-dispatchable generation in each of the LRET+VRET and LT Commitment renewable development scenarios and how this changes over time is evident.

Figure 43: Generation mix—modelled future weeks in the year shown (MW)

Weekly profile

Year



2020

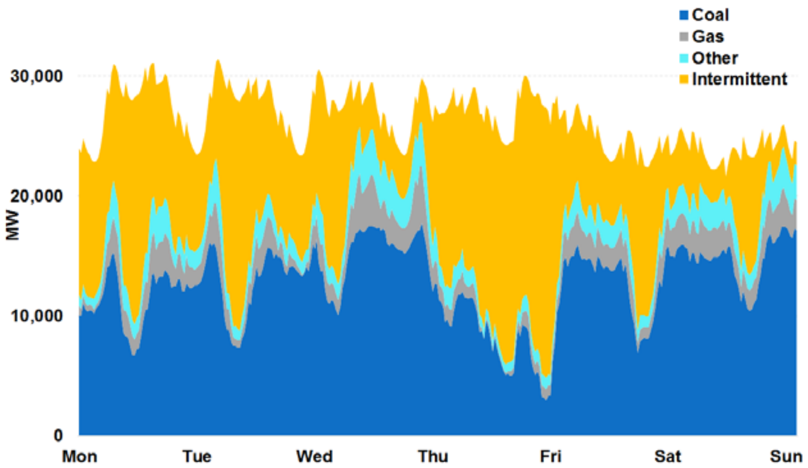
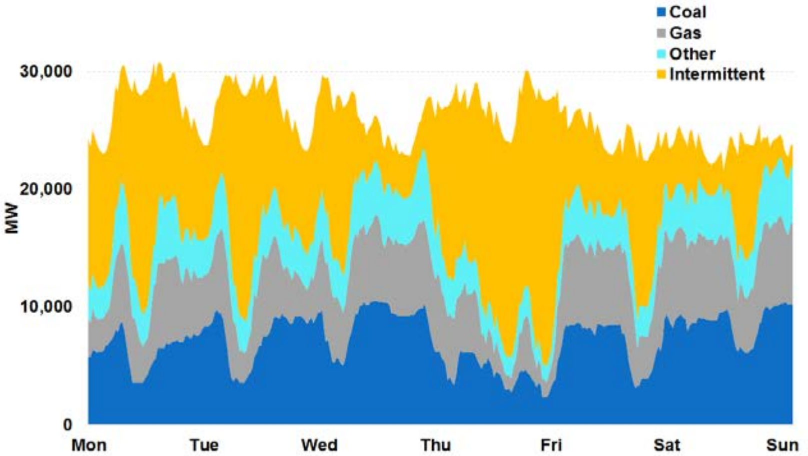
LRET satisfied

2025

Victoria 40% renewable

2030

Victoria and Queensland 50% renewable

Weekly profile	Year
	2040 NEM 60% renewable High renewable generation week
	2040 NEM 60% renewable Average renewable generation week

Source: Marsden Jacob, 2017.

11. Dispatchable generation and system outlook

This section presents the outlook for scheduled generation. The combination of the demand outlook, coal-fired plant closures and renewable generation development determines the amount of new dispatchable capacity needed, the operating profile of existing coal-fired generation (particularly the NSW generators) and the amount of renewable generation that may need to be reduced due to coal-fired plant inflexibilities.

Future NEM outcomes will be influenced by the age and economics of existing coal- and gas-fired plant and when it is planned to retire such plant. This chapter reviews the dispatchable generation outlook in terms of:

- planned generator closures and new generators
- operating costs (in particular, SRMCs)
- additional costs associated with increased plant cycling that may be associated with increased intermittent generation
- the revenues required for coal- and gas-fired plant to remain economic (to cover fixed and variable operating costs and to make a contribution to capital).

The demand outlook is also discussed, as are the implications of the demand and renewable generation outlook for coal-fired operation.

11.1 Dispatchable generator outlook

Planned coal- and gas-fired plant closures

While no closure of operating coal-fired power station has been announced (with the exception of Liddell), a number of them have been 'earmarked' for closure and we consider a number to not be economic beyond the dates indicated below.

The following coal-fired power stations are assumed to close:

- Liddell Power Station (2,000 MW):
  - AGL has announced its closure in 2022[85] and stated that the power station is to be replaced with solar generation and battery storage.
  - However, no final decision for closure has been stated.
- Vales Point Power Station (1,320 MW):
  - This power station has a licence to operate until the end of 2028.

85 We note that there is debate on the closure of Liddell Power Station between the Australian Government and AGL.

- We understand that rehabilitation work will be needed in 2024 to enable it to continue operating.
  - For those reasons, we have assumed that Vales Point Power Station will close in 2028.
- Eraring Power Station (2,640 MW):
  - Origin Energy has announced the closure of Eraring Power Station by the early 2030s.[86]
  - By 2032, Eraring will be 50 years old.
  - We have therefore assumed that Eraring will close in 2032.
- Yallourn Power Station (1,450 MW):
  - Yallourn was developed in the early 1980s and is now the most emissions-intensive power station in Australia.
  - Yallourn has coal supply problems associated with the depleting east field coal supply.
  - Its licence expires in 2031.
  - This indicates that Yallourn will close in or before 2031.

While there are many other coal power stations that would be increasing in age, only the above were assumed to close for the purposes of this report.

Generator entry

Table 1 (in Section 2.1.1) lists the package of developments that are being undertaken in South Australia as part of the South Australian Government's strategy to ensure supply reliability in the 2017–18 summer and beyond.

AGL had announced its intention to develop 210 MW 'fast start' plant to partially compensate for the retirement of all or part of the Torrens A Power Station. The announcement by the South Australian Government of a new gas generator as part of the package resulted in AGL cancelling plans to proceed with the 210 MW fast start plant.

No other dispatchable generators are being developed in the NEM. The reason for this is economics (due to the amount of renewable generation being planned) and the uncertain policy outlook.

Gas-fired generator operating costs

As described in Chapter 4, the operating costs of gas-fired generators are primarily determined by the cost of gas ($/GJ) and the generator heat rate[87] (GJ/MWh). The heat rate of new and existing generators is known. What are uncertain are the future cost and availability of gas.

The commencement of the LNG plants in late 2015 changed the gas balance in the market, making gas short market wide. The gas shortage was also associated with gas production declines in two of the three gas production centres outside Queensland—Moomba and Otway. Moomba has been in decline since 2008 and Otway since 2011. Gippsland, while having steady production, is projected to have a reduction in production resulting from the decline in existing fields and the capacity and reserves in new fields.

The market understood the emerging gas shortage position, and developers were and are keen to explore and develop onshore gas reserves in Victoria and NSW. However, perceived risks associated with fracking and public concerns have led to the governments of both those states prohibiting onshore gas development. These gas development restrictions are supported by both sides of politics in those states. Industry has lobbied to have this policy reversed, but without success.

Gas shortages and high prices resulted in a policy response from the Australian and South Australian

86 M Ludlow, 'Origin Energy to shut Eraring, ditch coal assets', *Newcastle Herald*, 21 October 2015, www.theherald.com.au/story/3436819/origin-energy-to-shut-eraring-ditch-coal-assets/ [8 November 2017].

87 The heat rate is the efficiency of the generator: energy in (fuel GJ) / energy out (MWh).

governments:

- The South Australian Government has enacted the Gas Exploration Incentives Scheme. The scheme will involve payments being made to landholders on the basis of the amount of gas that is produced.
- The federal government has enacted the Australian Domestic Gas Security Mechanism. The basic operation of the mechanism is a determination ahead of each calendar year stating whether there are likely to be gas shortages in that year. If shortages are likely, that year will be deemed a 'shortfall year'. During a shortfall year, controls are invoked to limit exports by liquefied natural gas (LNG) projects to the maximum extent that they are drawing from the market in net terms. The intent is to provide the LNG industry, which sets production and cargo levels in advance, with certainty about its licensed volumes for the following year.

Because gas production sources outside of Queensland are projected to decline in the future, and barring new gas developments in Victoria or NSW, coal-seam gas needs to be supplied from North Queensland, other parts of Queensland, the Northern Territory and unconventional Cooper Basin production (not including Victorian and NSW coal-seam gas).

With sufficient incentives, this gas can be developed for supply to Queensland as well as South Australia, Victoria and NSW.

This suggests that the most likely long-term outlook for the gas market is continued development of Queensland coal-seam gas or other gas sources, resulting in the six LNG trains operating at full capacity. The volume of Moomba gas required for the LNG plants will decline (eventually to zero) and gas will become available to South Australia, Victoria and NSW. The volume of gas from Queensland will be sufficient to compensate for the decrease in production from the producers in the southern states.

From time to time, situations may arise in which the production rates required for the LNG plants are short of the plants' requirements, and that could result in periods of increased gas costs reflecting the marginal cost in export markets.

This outlook reflects a working gas market that balances demand and supply. It provides for a return to gas availability in term contracts, although at considerably higher prices than in the past.

In this outlook, gas costs stabilise at about $8/J to $9/GJ (real 2017 dollars) for flat gas in 2020, and then increase slightly, reflecting a recovery in oil prices.

Coal-fired generator operating costs

Just as for gas-fired generators, the operating costs of coal-fired generators are primarily determined by the cost of coal ($/GJ) and the generator heat rate (GJ/MWh).

In addition, with an outlook of increasing intermittent generation, the costs of cycling coal-fired plant (in additional maintenance and reduced availability) may also become a significant component of coal-fired generator costs.

NSW black coal costs

The outlook for coal costs is uncertain due to the uncertainties about the status and cost structures of the NSW coalmines supplying the state's coal-fired power stations and future trends in global coal demand and supply.

The global outlook for coal is one of increased demand in the medium term but declining demand in the long term. For the NSW coal-fired plants, this could mean increased scarcity of supply and higher coal prices.

Given this uncertainty, coal prices have been assumed to increase slowly from current levels.

Coal-fired plant operations

We have assumed that the physical limitations and flexibility of the coal-fired generators will remain as currently reported. The particular issues are:

- the minimum generation levels at which coal-fired generators can operate (operating below those levels can require the use of high-cost 'auxiliary fuel', such as oil, to maintain stable flame in the boilers)
- the rate at which coal generators can increase and decrease generation (the ramp rate).

Within these limitations, high cycling of generators increases thermal stress on the generators and increases the maintenance required. However, the costs of such operations are not known.

11.2 Generator reserve outlook

A key issue in the generation requirements of the NEM is the outlook for generation adequacy. In other words, based on the demand growth and generator closures assumed, what new dispatchable generation is needed to maintain supply reliability (i.e. to keep the lights on).

In the past, the AEMO published required levels of dispatchable generation in each state under each demand forecast, but it has ceased publishing minimum generator levels and instead now provides outlooks of generation reliability expressed in terms of unserved energy.

Marsden Jacob undertook modelling to assess the level of dispatchable generation required in each state assuming the most likely AEMO demand forecast. The results of that modelling are shown in Figure 44.

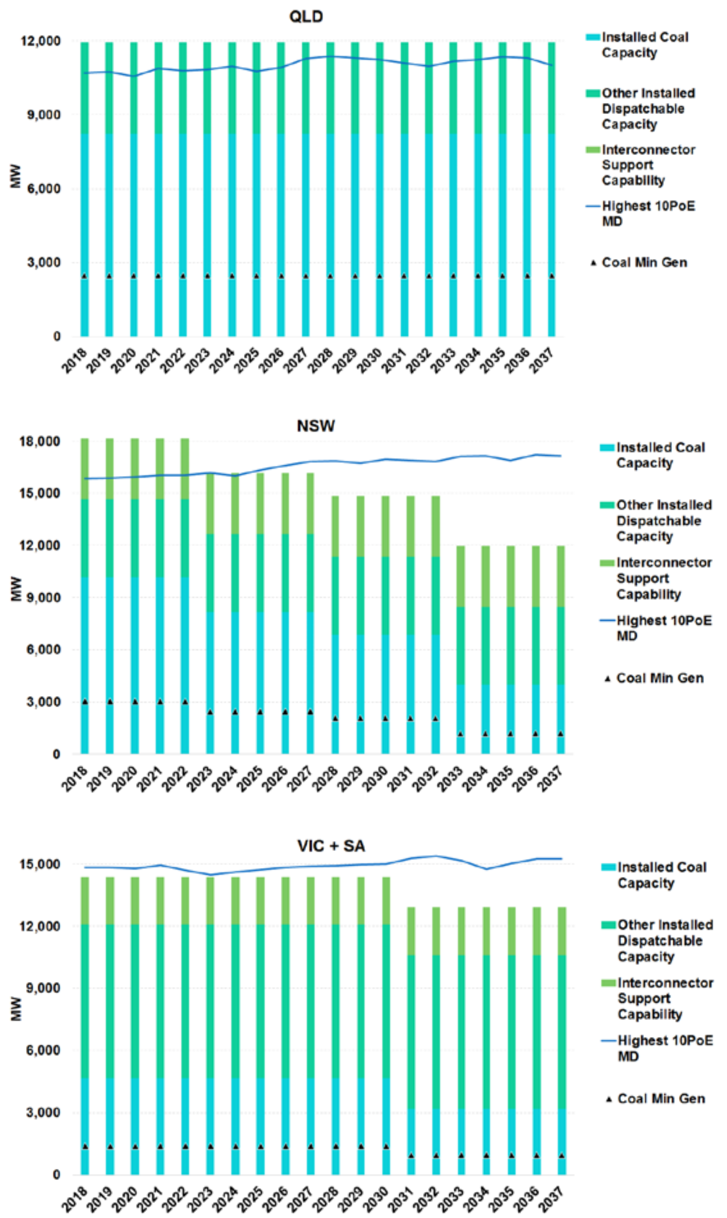
The three graphs in Figure 44 show, on an annual basis:

- the capacity of dispatchable generation and capacity available from neighbouring states (using flows on the interconnectors to that state)
- the maximum demand that can occur (labelled 'Highest 10 PoE MD').

To have sufficient capacity, there needs to be surplus generation above the maximum demand level. These graphs show that:

- Queensland has sufficient dispatchable capacity
- the closure of Liddell results in the system having no spare capacity, and additional coal-fired plant closures result in a large deficit
- there is currently a shortage of capacity for the combined Victorian and South Australian regions, and the closure of Yallourn would introduce a large capacity shortage.

Figure 44: Outlook for generation reserves (MW)



Queensland

No announced closures

New South Wales

Closures:

Liddell (2022)

Vales Point (2028)

Eraring (2032)

Victoria and South Australia combined

Closure:

Yallourn (2031)

Source: Marsden Jacob, 2017.

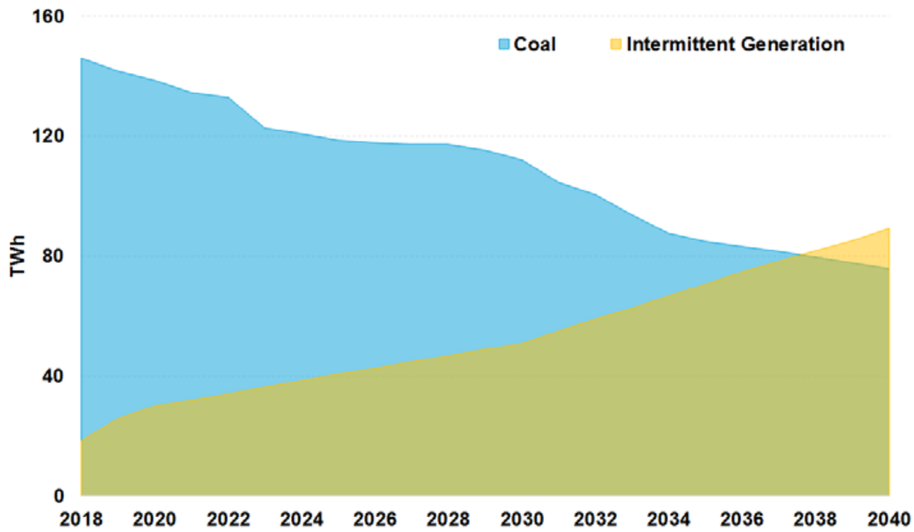
11.3 Coal-fired generator operation

Combining the outlooks of state demand, renewable generation development and coal-fired plant closures provides for a review of the annual energy production from renewable generation and coal-fired generation and the weekly profile of coal-fired generation over the outlook period.

Annual generation

Based on the demand outlook, assessed coal-fired generator closures and the LT Commitment scenario, Figure 45 shows the total coal-fired generation and large-scale intermittent generation (excluding rooftop PV) on a total NEM and yearly basis over the period from 2018 to 2040.

Figure 45: Total NEM-wide coal and intermittent generation, LT Commitment scenario, by year, 2018 to 2040 (GWh)



Note: excludes rooftop PV.
Source: Marsden Jacob, 2017.

This shows the following:

- Coal generation output in 2018 is 145,000 GWh and decreases to 76,000 GWh by 2040 (a decrease of 69,000 GWh). Of that decrease, approximately 43,000 GWh is associated the retirement of coal-fired generation (Liddell, Eraring, Vales Point and Yallourn) and 26,000 GWh is attributed to operating coal-fired plant being required to reduce output to accommodate the increase in intermittent generation.
- Intermittent generation (solar and wind) increases from 18,000 GWh in 2018 to 90,000 GWh by 2040 (an increase of 72,000 GWh). Since coal-fired generation decreases less than intermittent generation increases, the remainder is from other generation, most notably gas.

Weekly operating pattern

Based on the assumed demand outlook, coal generator closures and the LT Commitment scenario, we developed the weekly generation profile of coal-fired plant on a state-by-state basis through modelling. We did this in two ways:

- firstly on the assumption that coal generation did not have any minimum generation or ramping rate constraints. Under this assumption renewable generation will not be reduced
- secondly on the assumption that coal generation does have minimum generation or ramping rate constraints. Under this assumption renewable generation may be reduced.

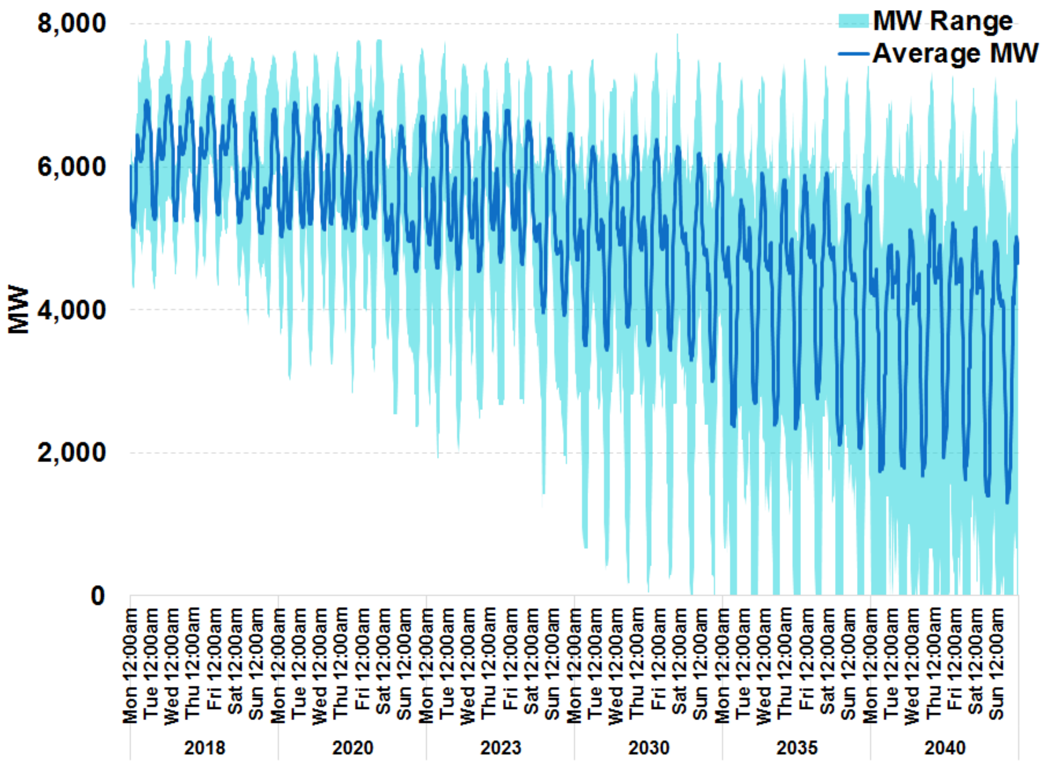
The purpose of the assumption of no coal operating constraints was to determine what this would mean for potential coal-fired generator operation. Comparing the two provided for the impact of coal operating constraints to be observed. Identified operational issues could mean reducing renewable generation or, for example, de-committing coal generation during periods of high wind energy generation, both of which involve significant cost.

The results of the modelling are shown in Figure 46, Figure 47 and Figure 48, which show the projected average weekly profile (solid line) and spread (shaded area) of coal-fired generation output in Queensland, NSW and Victoria, respectively, for sample years over the period from 2018 to 2040 for the LT Commitment scenario. The top graph has no coal plant operating constraints while the bottom graph does.

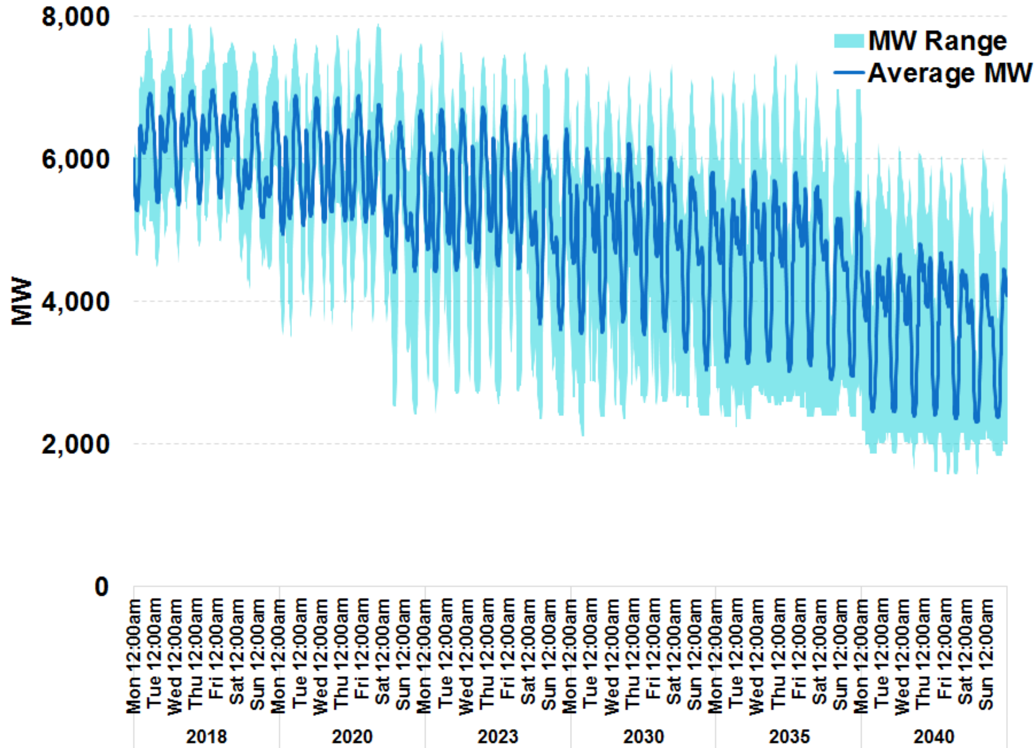
While the assessed coal-fired generator closures mean that the differences between the two described operating regimes are reduced, there remain many instances in which renewable generation would be required to be reduced in order to avoid the de-commitment of coal-fired generator units.

Figure 46: Coal-fired generation outlook, Queensland, LT Commitment scenario, selected years, 2018 to 2040 (MW)

Average weekly generation profile and spread – no minimum generation constraint



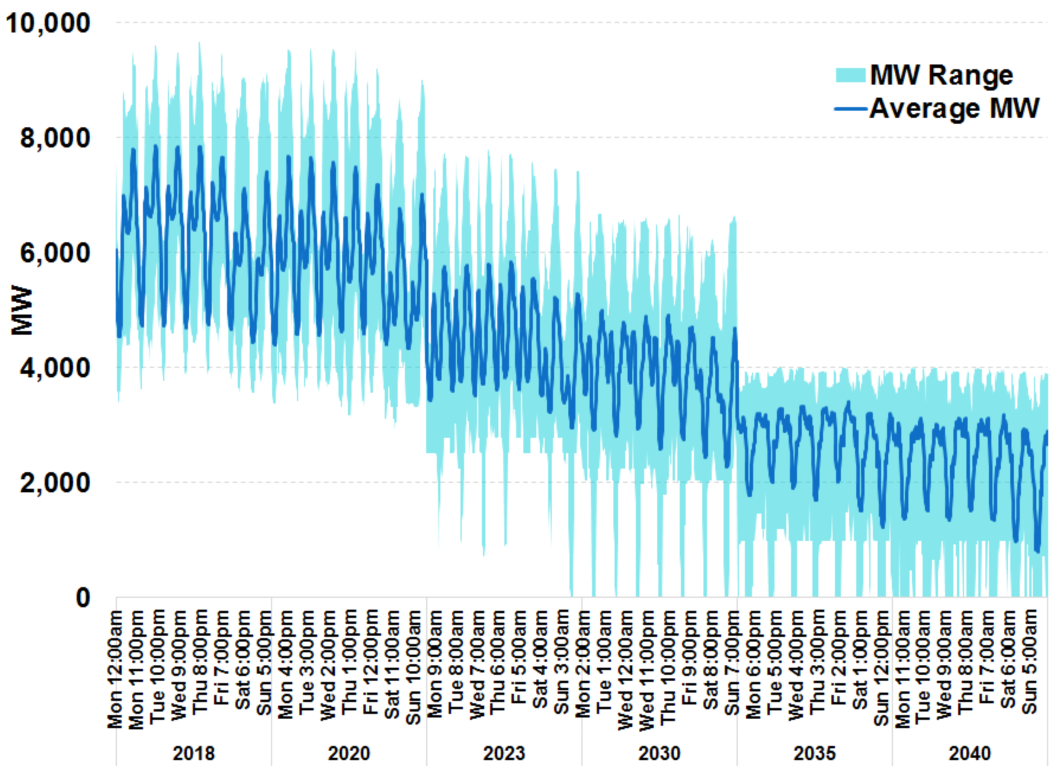
Average weekly generation profile and spread – minimum generation constraint



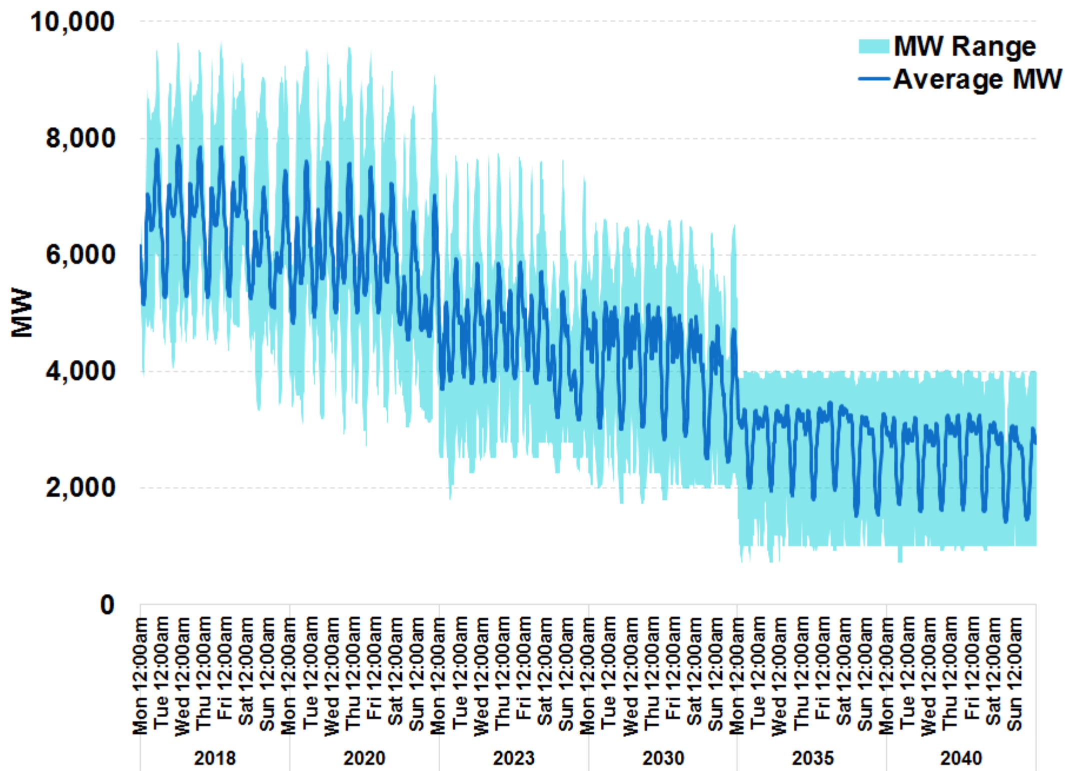
Source: Marsden Jacob, 2017.

Figure 47: Coal generation outlook, NSW, LT Commitment scenario, selected years, 2018 to 2040 (MW)

Average weekly generation profile and spread – no minimum generation constraint



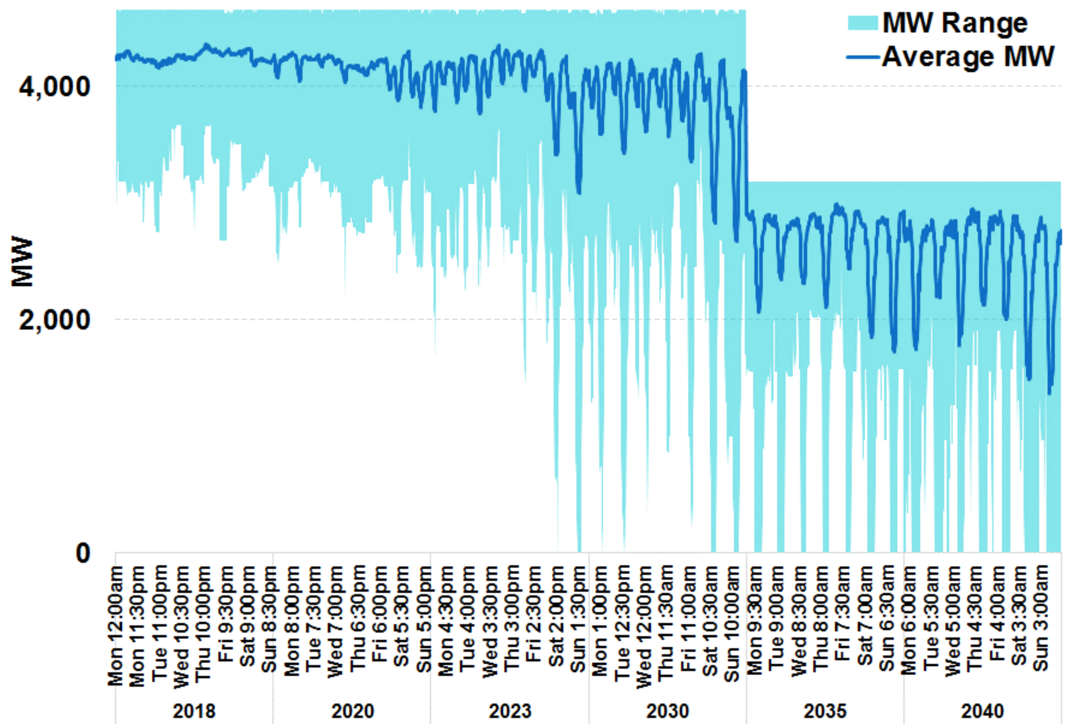
Average weekly generation profile and spread – minimum generation constraint



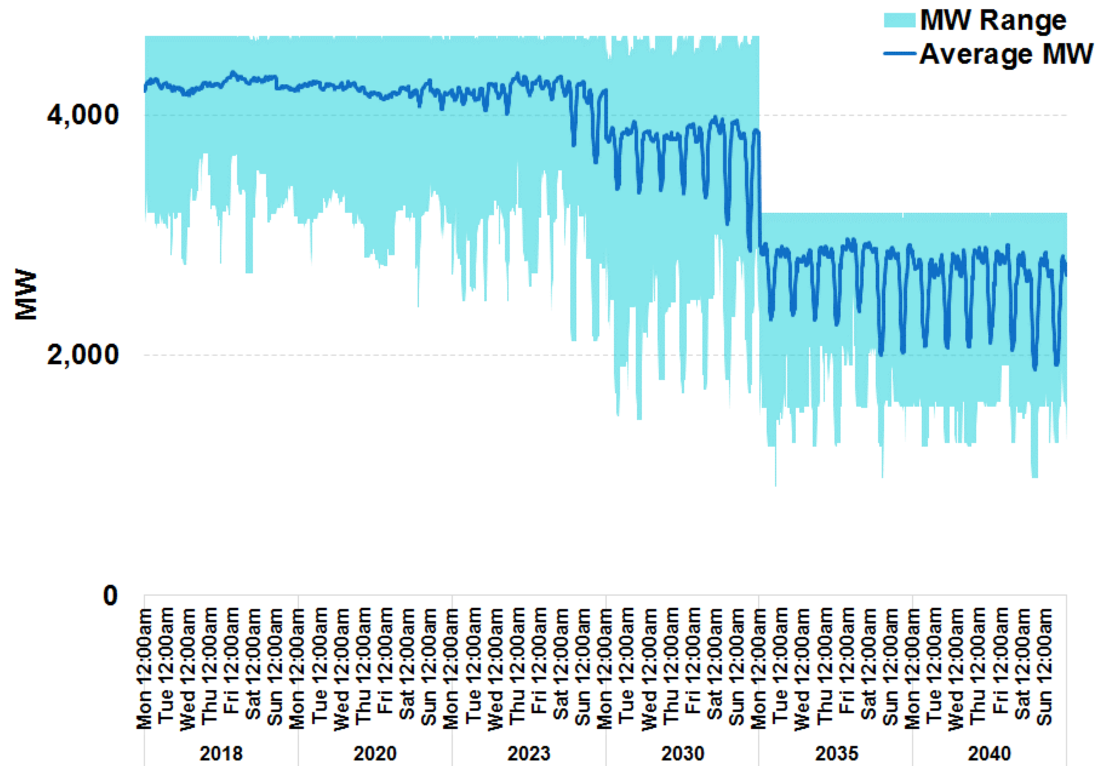
Source: Marsden Jacob, 2017.

Figure 48: Coal generation outlook, Victoria, LT Commitment scenario, selected years, 2018 to 2040 (MW)

Average weekly generation profile and spread – no minimum generation constraint



Average weekly generation profile and spread – minimum generation constraint



Source: Marsden Jacob, 2017.

Our observations on the figures showing the LT Commitment scenario are as follows:

- the generation operation required from the existing coal-fired fleet is problematic. All regions have significant periods when coal-fired generation would go to zero if renewables were not reduced
- the spread of coal-fired operation increases, particularly low-generation output (corresponding to conditions of high intermittent generation; that is, low dispatchable demand)
- intermittent generation in one region affects generation in neighbouring regions. In particular, the high level of intermittent generation in Queensland and no plant closures result in significant power flows to NSW
- if the NSW coal-fired generators do not close as assumed, those generators would operate with significant levels of offloading and output variation. This would mean that they would be unlikely to be economic. They would also impact all other generators in the NEM
- the costs of operation per unit of energy production increase significantly. This is due to capital costs associated with lower generation and the need to operate those generators in a more flexible manner.

11.4 Coal generation ramping limits

Daily variation in coal-fired generator output can occur only if the generators are physically capable of changing output (that is, ramping) as needed. If ramping rates are lower than are needed to accommodate the variation in renewable generation and demand, the following apply:

- If the limitation is in the rate of increase (due, for example, to increasing demand, decreasing wind generation, or both), more expensive generators would need to be used.
- If the limitation is in the rate of decrease (due, for example, to decreasing demand, increasing wind generation, or both), output from lower cost generators (such as wind) would need to be reduced.

To investigate this, modelling was undertaken on a 5-minute basis to better capture any limitations of coal-fired generator ramping limits. The modelling used observed ramping rates for generators and assumptions about how much renewable generation was operating (variations in future renewable generation were given by the LRET+VRET and LT Commitment renewable development scenarios).

PART E: Future NEM economics and the impact of Snowy 2.0

Based on the NEM outlook (for demand growth, renewable generation development scenarios, coal generation closures, fuel and capital costs) presented in the previous chapters of this report, this section describes the impact to the NEM Snowy 2.0 would provide and presents the results of our modelling to quantify this impact.

The framework used to quantify the impact Snowy 2.0 would have is the definition of *market benefits* as published by the Australian Energy Regulator (AER) in the Regulatory Investment Test for Transmission (RIT-T). The context of this test is the assessment of benefits a transmission asset would provide to the NEM as an input the determination of the Maximum Annual Revenues that asset can earn in the regulatory asset base.

Market benefits for Snowy 2.0 relate to the change in costs in the NEM of capital and operations (including fuel costs) that would be the result of developing Snowy 2.0.

A distinction is made between market benefits and wealth transfers between NEM participants that result from changes in price.

In some places, these chapters refer to graphs of plant operation and renewable development shown in previous chapters.

12. Market Benefits that could be provided by Snowy 2.0

This chapter considers how Snowy 2.0 would impact the NEM and the framework used to express the economics of this impact.

The impact Snowy 2.0 would have to the NEM is quantified by modelling the NEM under the assumption Snowy 2.0 is not developed, modelling the NEM under the assumption that Snowy 2.0 is developed, and comparing the changes of the without and with Snowy 2.0 cases. This was done for the two scenarios of renewable generation development as defined by the LRET+VRET scenario and LT Commitment scenario.

The "market benefits" framework developed by the AER in the RIT-T (2010) was used as the basis for quantifying the economic impact Snowy 2.0 would have to the NEM.

Snowy 2.0 would impact the NEM by one or more of the following pathways:

- increasing the use of low-cost fuels and reducing the use of high-cost fuels as a result of pumping at low-price times and generating at high-price times
- reducing the need for new dispatchable capacity (peaking generation, demand management, and batteries)
- allowing coal-fired plant to operate in a more stable mode. This would improve the economics of coal generation (due to not being required to shut down or reduce generation during periods of high intermittent generation, low demand, or both)
- increasing system inertia associated with new synchronous generators
- avoiding costs relating to FCAS provision
- lowering costs of generator operation under drought conditions through reduced need for gas generation
- lowering capital and generator operating costs under scenarios where new large-scale storage is required
- reducing spot price volatility and reducing contract premiums such as those purchased from institutions.

12.1 Market benefits

When a new transmission asset is proposed to be developed and included in the regulated asset base (the costs which are then passed onto consumers) the AER undertakes an assessment (known as the Regulatory Investment Test for Transmission or RIT-T) that among other things determines the market benefits of the proposed project and that of competing projects. The market benefits reflect the change in costs in the NEM that the proposed asset would provide.

The concept of "market benefits" as developed by the AER in the RIT-T was used as the basis for the framework for quantifying the economic impact Snowy 2.0 would have to the NEM. The definition of market benefits as presented in the RIT-T is presented in Appendix 7. The definition lists a number of factors. These factors were paired with the impacts that Snowy 2.0 would have to the NEM and that are described in the next section. This pairing is shown in Table 16:

Table 16 Matching of Market Benefit components and Snowy 2.0 Impacts

Market Benefits	Reported as follows
Fuel consumption	Generator operating costs
Voluntary load shedding	Assumed to be the same in all scenarios
Involuntary load shedding	None- reliability standard assumed to be met to all scenarios
Capital costs	New generator costs
Operations and Maintenance costs	Generator operating costs
Transmission investment	Assumed to be the same in all scenarios
Network losses	Generator operating costs (through change in generation)
Ancillary services	Ancillary services
Competition benefits	Accounted for through realistic generator bidding
Option Value	Option Value – scenarios that require new large-scale storage
Penalty for not meeting renewable energy target	LRET and VRET assumed to be met in all scenarios

12.2 Impacts of Snowy 2.0

Snowy 2.0 would impact the NEM is a number of ways. This section describes the categories of these impacts.

Savings in generator fuel and operating costs

Savings in generator fuel and operating costs result from the operation of pump storage to arbitrage spot prices in an environment of increasing intermittent generation. The assessment considered the market benefits of fuel cost savings under non-drought and drought conditions.

Saving in fuel costs under non-drought conditions

Savings in generator fuel costs would accrue from using low-cost generation when pumping, and reducing high-cost generation when Snowy 2.0 is generating. With only moderate levels of intermittent generation this would result from Snowy 2.0 pumping during low demand off-peak periods using spare base-load generation and using the pumped water during peak period to avoid higher cost generation, such as gas-fired generators.

With higher levels of intermittent generation, the opportunities for fuel cost savings from pumping increase but the pattern of pumping and generating becomes less predictable. High wind generation at times of low demand can result in the need for substantial pumping. In addition to increasing the use of low-cost base-load plant, pumped storage avoids the need to de-commit base-load units for short periods at high cost.

The signals for plant operation and energy trading in the NEM are spot prices. The savings in fuel costs reflect the level of alignment of spot price signals to the underlying fuel and operating costs. The energy buy and sell profile that will result from Snowy 2.0 will depend on:

- the profile of spot prices in NSW (as more intermittent generation enters and coal-fired generators close, spot prices will become more volatile)
- the amount of storage available and the amount required to be kept 'in reserve' for use during periods when spot prices move unexpectedly to very high levels (which can occur at any time).

Saving in fuel costs under drought conditions

Drought that reduces water inflows to the Snowy reservoirs, particularly Eucumbene and Jindabyne, reduces the energy available from the Snowy scheme and also the system's ability to provide capacity for extended periods when required. Pump storage provides increased value during drought and recovery conditions, as evidenced by the increased use of Tumut 3 pumping (at Snowy) during the 2007 drought.

Snowy 2.0 would provide for a greater certainty and supply of capacity into the NEM during drought conditions. This would mean less use of high cost gas generation and less need to develop standby capacity to respond to such conditions.

While there is debate about the future frequency of drought conditions, part of the changing climate is projected to be a greater frequency of dry conditions.

More orderly use of thermal generation

In a market with a significant and increasing amount of intermittent generation, the commitment and dispatch of thermal generation becomes more complex and variable. Associated with this are increased costs due to less efficient operating levels and additional commit/de-commit cycles.

By providing flexibility to respond to the swings of intermittent generation, Snowy 2.0 would provide for more orderly use of coal- and gas-fired generation. The impact to the NSW coal-fired generators, in particular, would be to reduce the cost of energy supplied from those generators, lower operational "stress" and potentially extend the period prior to units closing down.

While there would be benefits in relation to operating costs and capital due to extended operating life, the lack of data in this matter meant that no benefits were ascribed in this regard.

Reduced capital for dispatchable capacity

In a September 2017 report to the Australian Government, the AEMO stated:

> *AEMO's initial analysis indicates the NEM will need as much as 1,000 megawatts (or one gigawatt (GW)) of additional new flexible and dispatchable resources to replace the contribution of Liddell. Further analysis is warranted to confirm this preliminary estimate. However, the reserve requirement would increase if either projected new resources do not come online as currently forecast, more generation is retired, or any existing generators were to suffer catastrophic failure.*[88]

The AEMO report foreshadows coal-fired power station closures in NSW after 2030 that will increase the new dispatchable capacity required to over 2,000 MW. This requirement is likely to increase in future.

The assumptions of coal generator closures used in this report (that were presented earlier) are consistent with the commentary by AEMO.

The 2,000 MW dispatchable capacity of Snowy 2.0 would replace capacity that would otherwise be required for supply reliability, and that would be required to provide cap contracts required by retailers.

Snowy 2.0's ability to generate power continuously over a period as long as one week provides:

- the level of supply reliability and security that would be provided by thermal plant

88 AEMO, *Advice to Commonwealth Government on dispatchable capability*, September 2017, www.aemo.com.au/-/media/Files/Media_Centre/2017/Advice-To-Commonwealth-Government-On-Dispatchable-Capability.PDF [14 November 2017].

- the capability for Snowy Hydro to sell risk instruments, such as cap contracts, in the market. This also applies to the NEM after its introduces 5-minute pricing.

Increased generation inertia and greater system stability

Snowy 2.0 would bring high inertia machines into the system. By virtue of the nature and flexibility provided by hydro technology, those generator units can operate in 'spinning' mode without incurring significant costs.

The impact of increased inertia in the NEM is measured through reduced limitations on transmission power flows and avoided new assets, such as non-economic gas-fired generators or synchronous condensers.

These benefits have not been assessed for this study, but would arise from avoided costs of synchronous condensers or synthetic inertia via batteries. It is understood that the AEMC is considering how an inertia service would operate.

Availability of spinning generation for the provision of spinning reserve

Snowy Hydro is currently a significant provider of the FCAS 5-minute contingency service. This service is well suited, as Snowy Hydro does not need generators producing generation to provide the service. This service has not experienced the significant increase in spot prices that regulation and 6-second services have over the past two years.

Snowy 2.0 will be a provider of 6-second, 60-second and 5-minute contingency services. This capability would reduce associated costs of other providers.

Environmental benefits

For the purposes of this report, environmental benefits are considered to be reductions in greenhouse gas emissions (expressed as tonnes of CO_2e). If emissions were to be priced, any change in emissions would be an economic factor, as it would be an input cost to the supply of electricity.

Pumped storage would affect CO_2 emissions as follows:

- The power losses during each pumping cycle would increase electricity demand, requiring additional generation and consequently CO_2 emissions (assessed at the average emissions intensity of the NEM).
- Energy arbitrage would act to increase emissions by reducing low-cost gas-fired generation and increasing lower cost coal-fired generation.
- Energy arbitrage would also use renewable generation that might have been constrained off. This would act to reduce emissions.
- Storage improves the economics of renewable generation and provides for more additional renewable generation to be developed than would otherwise be the case[89]. This would act to reduce emissions.

For the reason there is no direct price on carbon emissions, this was not included in the market benefits that would be provided by Snowy 2.0

Option value and flexibility

The future of the NEM is unknown. Many scenarios are possible, including significantly more renewables development brought about by coal-fired power station closures due to asset age or damage, increases in demand, and more urgent action on climate change. Contingency measures are needed to ensure that options

89 The additional renewable generation developed due to Snowy 2.0 would reflect the improved economic effects that renewable generation has on the spot market and the cost-effective firming service that Snowy 2.0 would provide for renewable generation, allowing renewable generation to be a larger component of a retail energy mix.

are available to address such issues.

The development of Snowy 2.0 would provide the infrastructure for additional and more quickly constructed (than would be otherwise) new capacity through additional pumped storage in the Snowy system. This can be viewed as the provision of a real option that addresses the NEM's need for insurance against such contingent events (which may become increasingly valuable in the future). Changes that could occur in the future include:

- unexpected coal-fired plant retirements due to age, reliability, reputation and maintenance costs
- a greater influx of renewable generation, particularly solar, than expected
- the failure of battery technology to provide economic storage
- higher oil prices, which will significantly increase electricity generation costs
- the inability of new coal-fired generation to operate in the 'new' NEM environment
- market rule changes, such as 5-minute energy settlement, that cause OCGT plant to operate differently or reduce the availability of risk management contracts.

The most likely changes are those to do with deteriorating performance or closure of ageing coal-fired generators, increasing demand, and increasing renewable generation.

The 'real option' value that Snowy 2.0 would provide relates to:

- the times that additional pumped storage developments can be undertaken
- the flexibility for pumped storage to address different issues, such as energy cost savings and capacity provision.

The value of such optionality was assessed through scenario analysis.

12.3 Wealth Transfers

Wealth transfers refer to the cash flows between the participants in the NEM. Cash flows are determined by the quantity sold each 30-minute and the price for that 30-minute period.

In an energy-only spot market, the spot energy price represents the revenue and payment for all services associated with energy provision. Spot energy trades capture the costs associated with energy supply (including transmission losses) and the dynamics associated with generator pricing policies and market power. In the energy market, additional revenues arise from contract sales and ancillary service provision (frequency control, network support and black system restart).

It is the outturn energy prices in the with and without Snowy 2.0 cases that determine the change in wholesale energy costs to consumers.

The impact on costs to retailers and consumer prices is addressed in Chapter 15.

13. NEM outlook without Snowy 2.0

This chapter presents the outlook for the NEM on the assumption that Snowy 2.0 is not developed. This is the reference case against which the market benefits of Snowy 2.0 are measured. The assumptions of demand growth and generation costs are as presented in the preceding chapters.

Two scenarios of NEM development without Snowy 2.0 were modelled based on the two scenarios of renewable generation development presented in section 10.1 (LRET+VRET and LT Commitment scenarios). These scenarios are labelled:

- LRET+VRET: no Snowy 2.0
- LT Commitment: no Snowy 2.0.

The key NEM outcomes for each scenario are:

- the development of generation—coal-fired, CCGT and OCGT plants
- the development of additional renewable generation based on economics
- the development of battery storage
- the manner existing and new generators would operate and the output from these generators.

The key findings of the modelling were that:

- coal-fired generation closures result in a capacity shortage that requires new (sustainable) dispatchable capacity
- intermittent generation affects the operation and costs of coal plant
- high levels of intermittent generation result in reduced economics of dispatchable generation
- battery storage is not sufficiently economic to address the intermittency and the capacity shortage associated with the coal-fired plant closures.

The lack of storage results in increasing costs associated with increased levels of renewable generation development.

13.1 Modelling results

For the two cases ('LRET+VRET: no Snowy 2.0' and 'LT Commitment: no Snowy 2.0'), the following modelling results are presented on a state-by-state and total NEM basis:

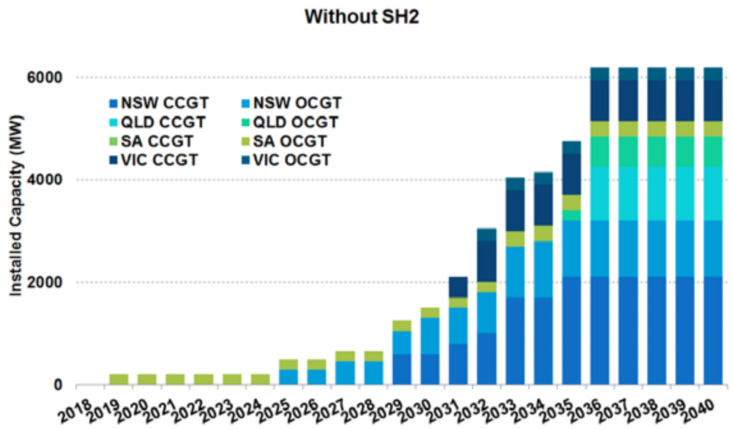
- new entry generation—dispatchable generation, renewable generation and batteries
- coal generation operation – typical profile of NSW coal plant operation
- battery installation
- generator output – by fuel type.

Other results are shown in the following chapter in order that they can be directly compared to the corresponding scenarios with Snowy 2.0 assumed to be developed.

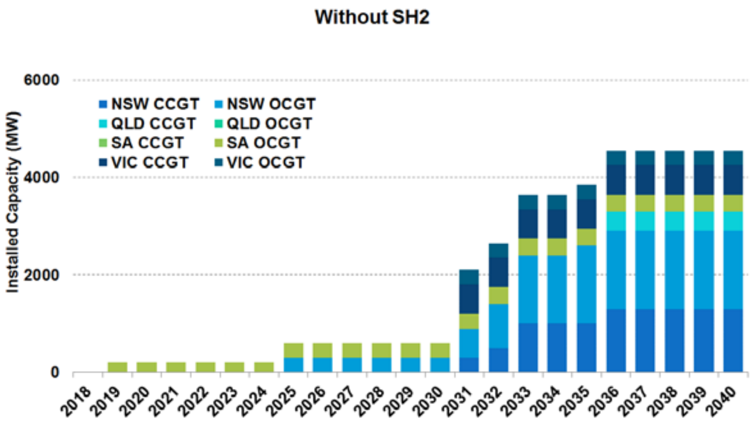
New-entry dispatchable generation

Figure 49 presents the new-entry dispatchable generation by fuel type for the LRET+VRET and LT Commitment development scenarios.

Figure 49: NEM-wide new-entry generation, without Snowy 2.0 (MW)



LRET+VRET scenario



LT Commitment scenario

Source: Marsden Jacob, 2017.

The increased level of renewable generation associated with the LT Commitment scenario results in 1,600 MW less dispatchable generation (OCGT, CCGT) entering the NEM. The main reason for this is the reduction in spot energy prices associated with the large increase in renewable development.

This is problematic if the higher level of renewable generation does not provide the support for system reliability equivalent to the 1,600 MW of dispatchable generation not developed. It could be argued that the current reliability setting (maximum price cap and cumulative price threshold) has been insufficient to provide the required level of dispatchable generation to ensure system reliability (as demonstrated by the outcomes in South Australia and the principles of the National Energy Guarantee scheme).

The reduced level of dispatchable generation under the LT Commitment scenario meant that there was less controllable generation to address periods where dispatchable generation was required. This meant that spot price volatility could be high when intermittent generation was low. (This dynamic has been observed in South Australia on low wind generation days).

This suggests that renewable generation will require firming, and that dispatchable generation economics may need an additional revenue stream in a market of high renewable generation. Such a revenue stream could be associated with cap contract premiums.

Renewable generation

The absence of large scale storage meant that no renewable generation was developed above the assumed level in either the LRET+VRET or the LT Commitment scenario.

This meant that on the margin the renewable generation developed was not economic on spot energy prices alone (the average energy price obtained by wind and solar generation is less than the time weighted average spot price). The cost of battery storage meant that they were not economic in this role. In particular, additional revenues may be needed for renewable generation to obtain the level of renewable generation development assumed in either scenario. Higher subsidies would be required in the LT Commitment scenario.

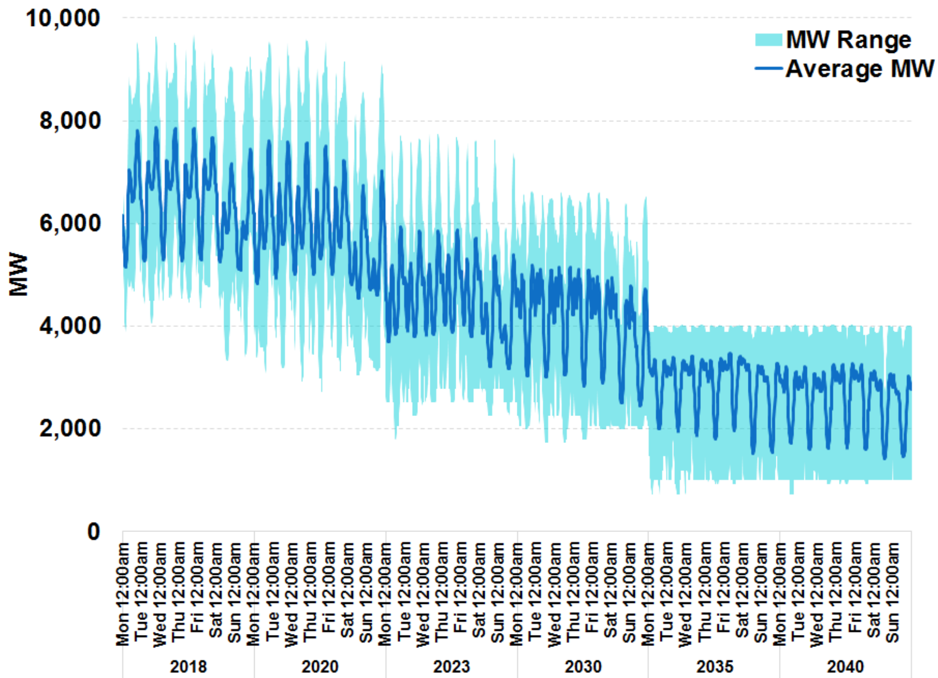
There was a small amount of offloading of renewable generation in the LRET+VRET scenario and a substantial amount in the LT Commitment scenario. The level of offloading was due to the minimum generation levels of operating coal- and gas-fired generation and the maximum rate at which that generation can change output (that is, ramp).

The level of offloading is shown in the next chapter for the two renewable development scenarios with and without Snowy 2.0 in service.

Coal-fired plant operation

The profile of NSW generation (average weekly profile and spread) under the LT Commitment scenario is shown in Figure 50. As observed, the frequency of times the NSW coal generators are operating at minimum levels (brought about by low demand and/or high intermittent generation) increases through the period. This is despite coal generators closing which reduce the combined minimum generation level. By 2035 the NSW coal generators are frequently constraining intermittent generation.

Figure 50: NSW coal generation, weekly profile in selected years, LT Commitment scenario, minimum generation constraint



The stepping down profile of the NSW coal generation is due to the closures of coal generators that reduces the total capacity available.

The reduced shape of coal generation after 2033 reflects generation frequently operating at maximum output and at minimum output

Source: Marsden Jacob, 2017.

No additional coal generation closed due to economics. The LRET+VRET scenario had limited renewable generation developed in NSW and Queensland and the impact of coal-fired generation was not significant. The LT Commitment scenario had a significant impact on coal generation operation.

In relation to coal plant operation in the two renewable development scenarios:

- in the LRET+VRET scenario the flexibility of coal-fired plant on a NEM-wide basis was mostly sufficient to accommodate the variation in intermittent generation (and demand). As previously observed, the level of renewable generation offloading in this scenario is small.
- in the LT Commitment scenario the flexibility of the coal-fired plant on a NEM-wide basis was not sufficient to accommodate the variation in generation.

However, in both scenarios (and particularly in the LT Commitment scenario):

- the cycling and ramping demands of the coal-fired plant may not be sustainable, creating the potential for significant renewable generation offloading
- the low capacity factor operation of coal-fired plant increases the cost of operation. This reduces coal generator economics and potentially brings forward potential closures of this plant.

However all coal generators had positive operating surpluses and remained open.   These results excluded the impact on coal generation of cycling operation, which if fully considered, has the potential to force additional coal generators to close.

Given the age of the coal-fired generation fleet, it would be expected that one or more coal power stations, in addition to those assumed to close, would close. This would require new generation for both energy and capacity. The lowest cost options would be likely to be renewable generation (solar and wind) on the basis economic storage was available.

Battery utilisation

The installation of batteries moving forward is highly uncertain.   The reason for this is the complexity of issues associated with a decision to develop a large-scale battery installation. These issues include:

- the economics of battery development which is highly dependent on future decreases in battery costs
- the level of subsidies (if any) that will be made available
- in incentives for commercial and industrial consumers to develop own generation (such as solar plus battery) due to increasing electricity prices
- obtaining revenues in the FCAS markets
- the necessity /benefit of batteries under 5-minute pricing (the rules of which are not yet fully known)
- retailer risk management policies.

The modelling found that battery economics required revenues in addition to those that could be obtained through spot market arbitrage, the value associated with fast response under 5-minute pricing, and the likely revenue from providing FCAS services.

Due to the uncertainty in the level of battery development a range of battery development was considered. This ranged from:

- a conservative take-up based on a percentage of peaking generators having storage, to
- a higher take-up (and possibly a more realistic) that placed greater value on the need for fast response and the need for individual parties to firm-up their respective intermittent generation assets.

The conservative profile of battery development had close to 900 MW of batteries developed by 2030, while the increased profile had approximately 1,800 MW of batteries developed by 2030.

The profile of battery development is shown in the following chapter of the two renewable development scenarios with and without Snowy 2.0.

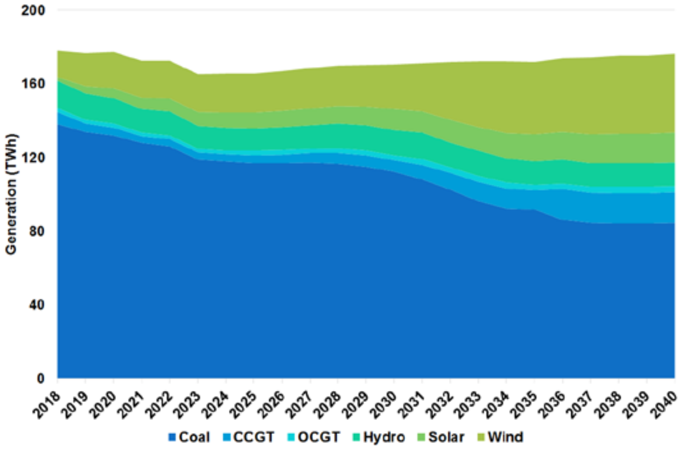
In the longer run, the utilisation of behind-the-meter batteries with rooftop PV systems and electric vehicles was noted, but there is insufficient evidence to conclude how that will respond to signals in the wholesale energy market.

Dispatchable generation output

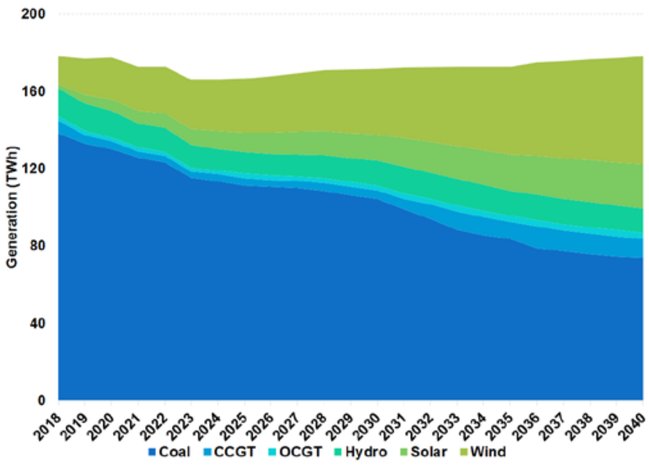
The dispatch level of the scheduled generators, by fuel type, is shown in

Figure 51. The reduction in dispatchable generation is shared across gas- and coal-fired generation.   This is to be expected as coal and gas generator offers to AEMO (i.e. their "bids" to generate) are interleaved.

Figure 51: Dispatchable generation, by fuel type, without Snowy 2.0 (TWh)



LRET+VRET Scenario



LT Commitment Scenario

Source : Marsden Jacob, 2017.

Use of existing pumped storage at Snowy

As previously noted, Tumut 3 pumped storage generation competes with generation already available using water from upstream reservoirs, meaning that this storage does not provide additional capacity when required. It does provide additional energy-shifting capacity. The operation of Tumut 3 pumped storage has recognised value opportunities and averaged higher levels of utilisation than in the past.

14. NEM outlook with Snowy 2.0

The market benefits that Snowy 2.0 would provide were determined through modelling the NEM scenarios presented in the previous chapter, with Snowy 2.0 assumed to enter service on 1 July 2025, and comparing the differences.

Using a similar structure to the previous chapter, this chapter presents the modelling results for the 'with Snowy 2.0' scenario and an explanation of the results.

For each of the renewable development scenarios, the modelling results also show the changes that occurred from the results in the corresponding alternative (or 'no Snowy 2.0') scenario. For each of the renewable development scenarios (LRET+VRET and LT Commitment), it is the change from the alternative case that determines the respective components of the market benefits that Snowy 2.0 would provide.

Scenarios were labelled:

- LRET+VRET: with Snowy 2.0
- LT Commitment: with Snowy 2.0.

The economic costs comprised:

- the change in capital expenditure: new generation
- the change in operating costs, principally fuel (the impact of drought on generation use was included but separately modelled)
- the supply of ancillary services (mainly frequency control)
- the option value to develop large-scale pumped storage quickly and economically that would not be available without the development of Snowy 2.0 (this also provides a level of 'insurance' to the NEM to address unforeseen events, such as rapidly deteriorating coal-fired plant).

The key findings of the modelling were as follows:

- Snowy 2.0 provides substantial market benefits (in terms of reduced new generation and lower operating costs).
- The entry of Snowy 2.0 increases the economics of renewable generation and results in additional renewable generation entering under the LRET+VRET scenario.
- Additional pumped storage would be needed to provide for renewable generation to be economic at levels higher than those approaching the LT Commitment scenario.
- The market benefits provided by Snowy 2.0 are greater at higher levels of renewable generation.

Not included in these benefits is the potential to extend the life of the existing coal-fired generators through more stable operation.

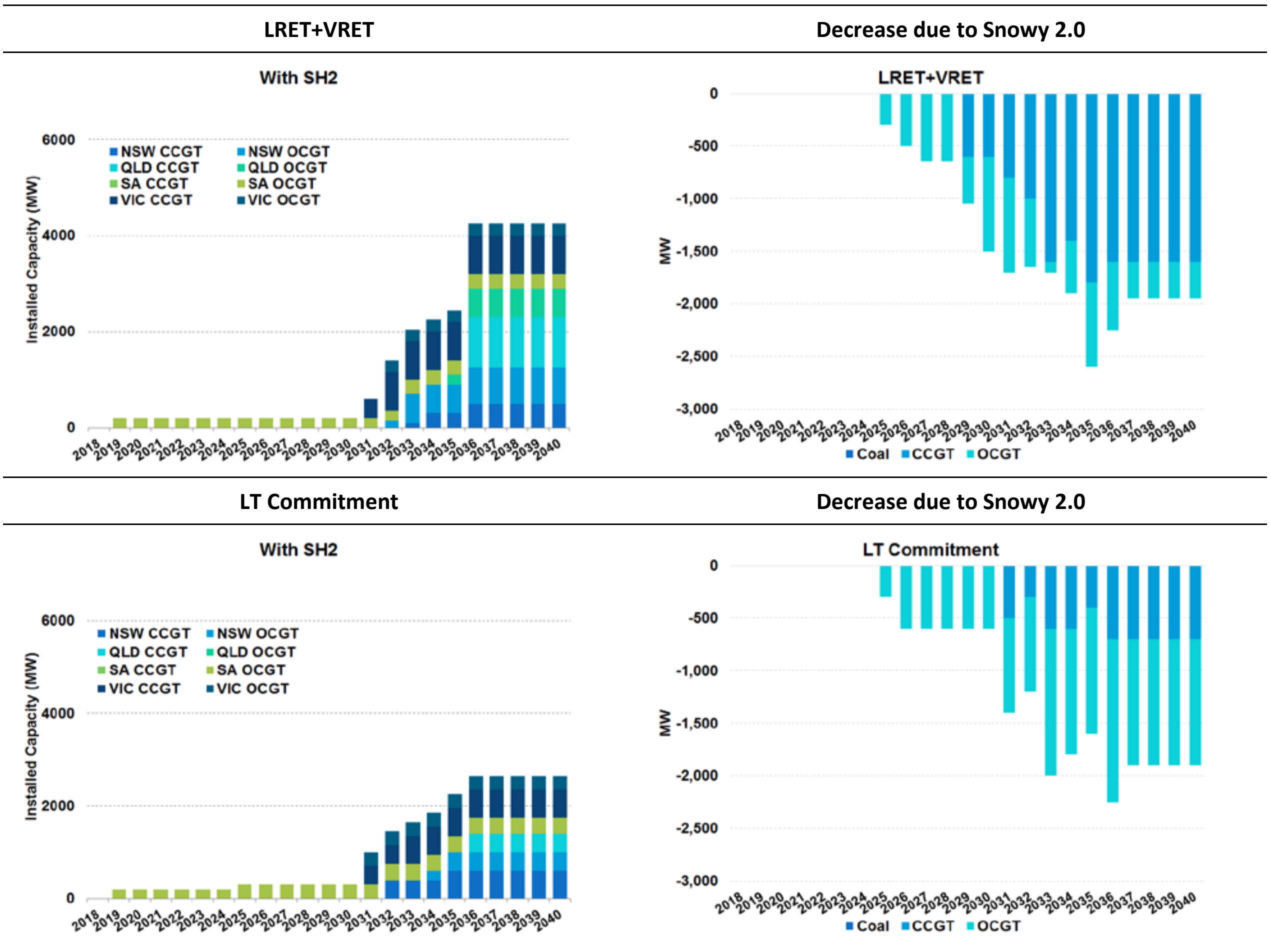
14.1 Modelling results

New-entry dispatchable generation

Figure 52 shows NEM-wide renewable generation by plant type:

- Left: new-entry dispatchable generation by fuel type for the LRET+VRET and LT Commitment scenarios ‘with Snowy 2.0’
- Right: the change in renewable generation development compared to the ‘no Snowy 2.0’ case (negative values represent reductions).

Figure 52: NEM-wide new-entry scheduled generation, with Snowy 2.0 (MW)



Source: Marsden Jacob, 2017.

As for the ‘no Snowy 2.0’ scenarios, the generation closures result in a capacity shortage that requires additional dispatchable capacity to address. Snowy 2.0 reduces the amount of new dispatchable generation required.

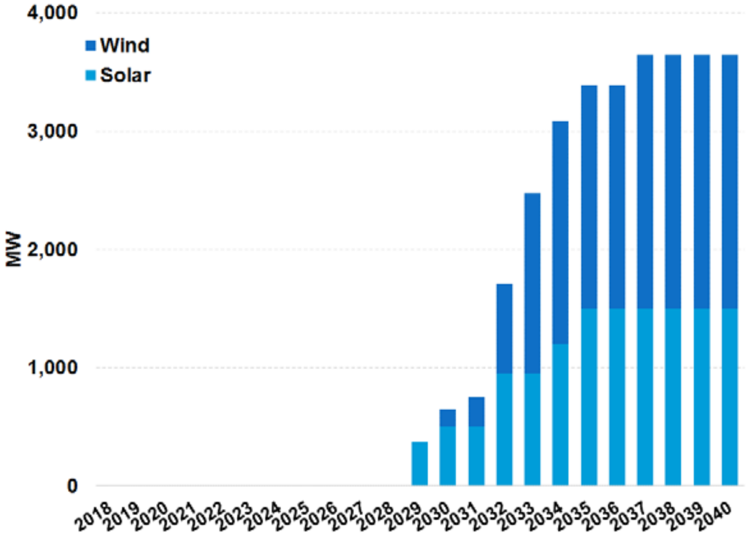
Renewable generation entry and output

Additional economic entry

The amount of additional renewable generation development above that assumed in either the LRET+VRET or the LT Commitment scenario is shown in Figure 53. This showed that:

- in the LRET+VRET scenario there was additional renewable generation development based on economics in the spot market. This additional level caused the amount of renewable generation developed in NSW to approach that in the LT Commitment scenario for NSW
- in the LT Commitment scenario there was no additional renewable generation development. This illustrates that the capacity of Snowy 2.0 was insufficient to cater for the amount of renewable generation in this scenario. Additional storage would be required for additional renewable generation to be economic.

Figure 53: Additional renewable generation development, with Snowy 2.0 (MW)



LRET+VRET scenario

No chart – no additional renewable generation enters

LT Commitment scenario

Source: Marsden Jacob, 2017.

Offloading of renewable generation

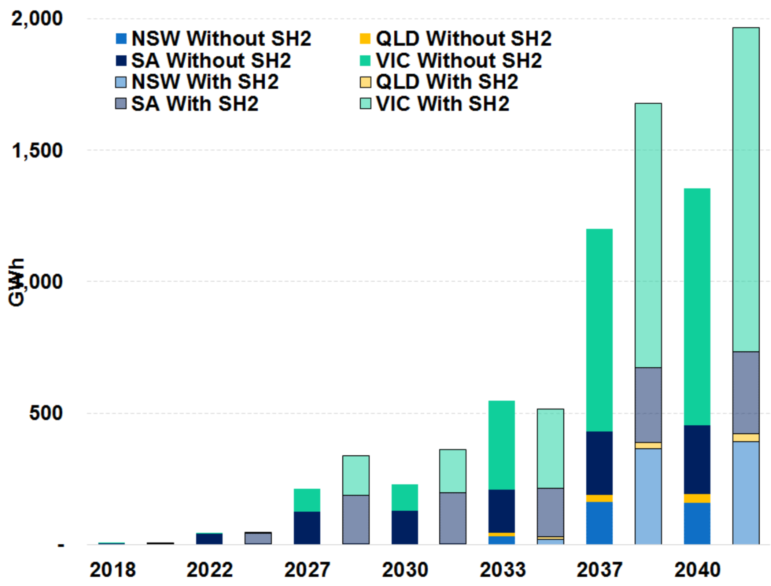
As previously described, renewable generation would be reduced if the flexibility of the operating thermal generators is insufficient to cater for the combined variation in demand and renewable generation (for example, if demand is rapidly decreasing while wind generation is rapidly increasing).

The amount of renewable generation offloading from the modelling is shown in Figure 54. The top graph is for the LRET+VRET scenario and the bottom graph is for the LT Commitment scenario. Each graph shows, for a selection of years and by state, the offloading for the with and without Snowy 2.0 cases. The scale for the LT Commitment scenario is seven times that for the LRET+VRET scenario.

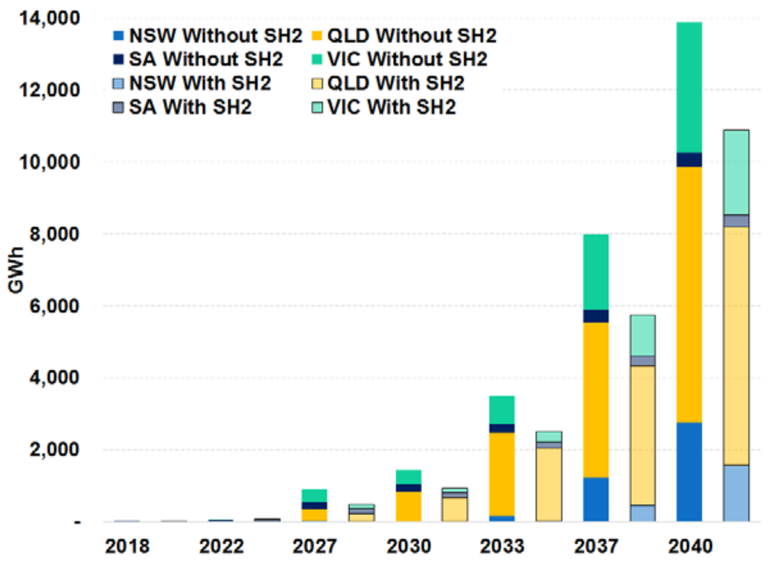
The main observations are as follows:

- For the LRET+VRET scenario, the amount of renewable generation offloading is similar for the with and without Snowy 2.0 cases. The reason for this is the additional renewable generation developed (the amount of offloading is influenced by both the amount of renewable generation operating and Snowy 2.0).
- The amount of offloading is very large in the LT Commitment scenario. Much of this occurs in Queensland, where Snowy 2.0 has limited reach.

Figure 54: Renewable generation offloading due to coal-fired generation constraints, with Snowy 2.0 (GWh)



LRET+VRET scenario, with and without Snowy 2.0.



LT Commitment scenario, with and without Snowy 2.0.

Source: Marsden Jacob, 2017.

Battery utilisation

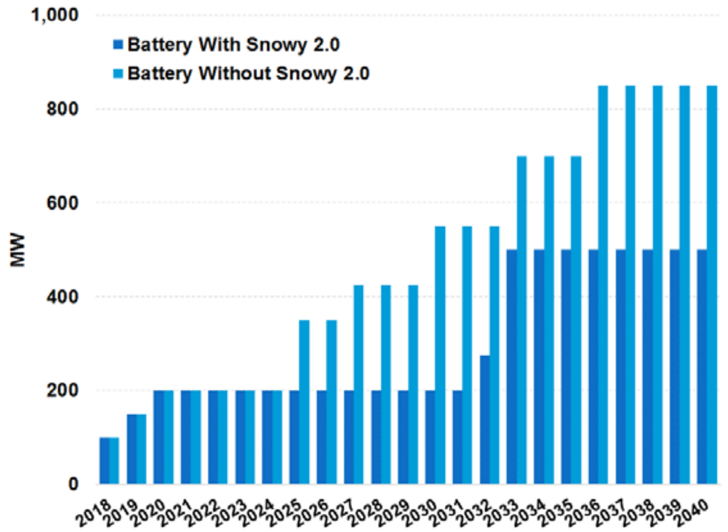
The impact of Snowy 2.0 was to provide firming generation and alternative support for cap products that cover the first 5-minutes.

The uncertainty in battery economics had two battery development profiles for each one of the renewable generation development profiles as described in the previous chapter. The relevant matter from the perspective of Snowy 2.0 impact is the reduction in battery installations that would results from the development of Snowy 2.0.

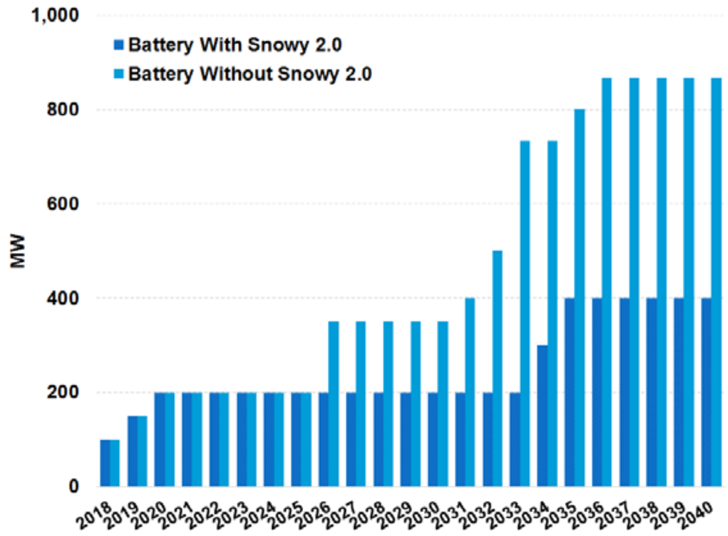
Figure 55 shows the conservative battery installation profile for the two renewable development scenarios and for each the development with and without Snowy 2.0. The moderate level of battery deferral is conservative in relation to the market benefits provided by Snowy 2.0.

The higher battery development profile, which was twice the conservative profile, provided twice the level of market benefits.

Figure 55: Profile of battery installation (MW) – Conservative battery development profile



LRET+VRET scenario, with and without Snowy 2.0.



LT Commitment scenario, with and without Snowy 2.0.

Source: Marsden Jacob, 2017.

Dispatchable generation levels under conditions excluding drought

Figure 51 showed the dispatch levels of the scheduled generators, by fuel type, without Snowy 2.0. Figure 56 below shows, for each of the renewable development scenarios, the change in dispatchable generation and renewable generation from that without Snowy 2.0 to that with Snowy 2.0[90]. Negative numbers represent reductions in generation. The explanation for the changes is described below.

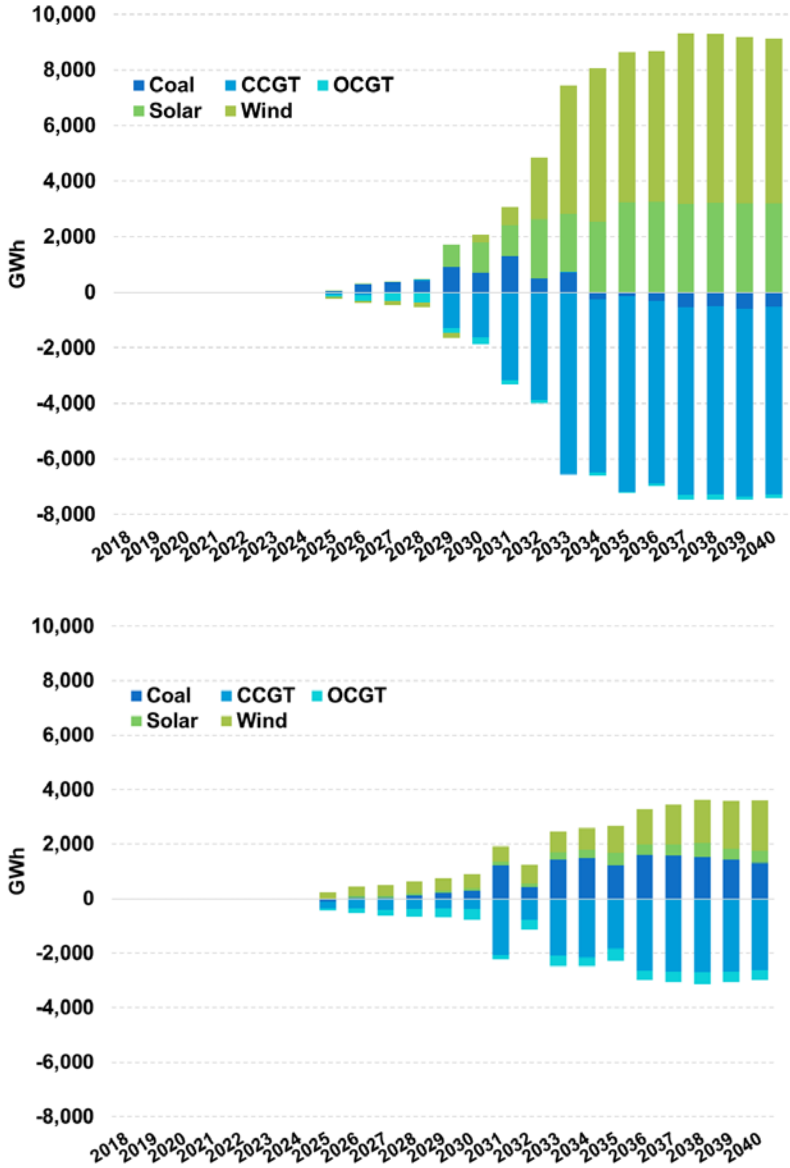
For the LRET+VRET Scenario:

- in the early years there is a slight increase in coal generation and a slight decrease in gas generation. This reflects that prior to Vales Point closing the opportunities for gas to coal are limited. There is also coal to coal arbitrage during this time (i.e. coal is marginal at time of both low and high spot prices)
- as Snowy 2.0 makes additional renewable generation entry economic and as this enters the NEM, increased renewable generation decreases dispatchable generation. This combined with the energy

[90] This is the generation level with Snowy 2.0 minus the generation level without Snowy 2.0.

arbitrage undertaken by Snowy 2.0 has the majority of dispatchable generation decrease being CCGT plant.

Figure 56: Change in dispatchable and renewable generation output due to Snowy 2.0, by fuel type (GWh)



LRET+VRET Scenario

LT Commitment Scenario

Source: Marsden Jacob, 2017.

For the LT Commitment scenario:

- the early years resemble the outcomes in the LRET+VRET scenario, although the faster ramp up of renewable generation results in slightly larger changes
- with no additional renewable generation entry, the increase in generation is renewable generation that would have been offloaded without Snowy 2.0 and coal generation. Gas generation is reduced. The large amount of renewable generation meant that the capacity of gas generation was less than in the LRET+VRET scenario
- there was also coal to coal energy arbitrage associated with coal generation being the clearing generation type at time of high spot prices. This results in an increase in coal generation associated with losses.

14.2 Drought protection

The economic impact and associated revenues to Snowy 2.0 obtained from the market modelling did not include severe drought scenarios that would reduce inflows to Snowy to very low levels, with corresponding reductions in Snowy generation.

During the 2007 drought, pumping at Tumut 3 increased significantly for the purposes of increasing the generation available at high-demand times. The drought (which also effected thermal plant due to cooling water limitations) resulted in a substantial lift in peak period prices.

Snowy 2.0 has a power capacity factor of less than 20% for most years. This means that it has the capability to increase pumping operation and generation should that be necessary and economic.

To account for the additional pumping and associated market benefits that would occur during severe drought, a scenario analysis was undertaken of the frequency of droughts and the savings Snowy 2.0 would provide to the NEM under such conditions. The assumptions were:

- drought conditions occur on average once every 25 years
- that there is a 5% probability that will occur in 2033
- if no drought occurs in 2033, there is a 5% probability that it will occur in 2034, and so on
- the market benefits that Snowy 2.0 provides during drought is to replace gas-fired generation that would be needed without Snowy 2.0 with coal-fired generation (accounting for losses) that Snowy 2.0 would utilise.

The present value of market benefits (4.55% over the period to 2074) was assessed to be $24 million. This was considered conservative.

14.3 Ancillary Services

Ancillary services—FCAS

Snowy provides ancillary services, frequency control and black system restart. Snowy 2.0 would also be able to provide those services.

Based on historical FCAS prices and the capability of Snowy 2.0 to provide FCAS, it was assessed that Snowy 2.0 would on average supply 60 MW of 6-second raise and 200 MW of 5-minute raise. The prices for those services were based on competitive market conditions and historical price outcomes. This had 6-second raise at $2/MWh and 5-minute raise at $1.50/MWh. The costs of provision were assessed to be $1/MWh for 6 second raise and $0.75/MWh for 5-minute contingency.

We assessed ancillary service requirements to be higher under the LT Commitment scenario compared to the LRET+VRET scenario. This resulted in a slightly higher level of provision costs in the LT Commitment scenario.

Based on those assessments, the present value of revenues (4.55% over the period to 2074) from the provision of FCAS was determined to be $33 million for the LRET+VRET scenario and $40 million for the LT Commitment scenario.

Ancillary services—Inertia

The provision of increased inertia acts to stabilise the system. This can result in reduced expenditure on other assets or increased power flow limits. This is not contingent on there being a market for inertia.

It was beyond the scope of this study to assess what the market benefit impact of these services on the NEM would be. However, it is recognised that the increased inertia would have benefits for the NEM.

14.4 Option to develop additional pumped storage

As previously noted, the infrastructure developed as part of Snowy 2.0 would allow additional large-scale pumped storage capacity to be developed (at Snowy) quickly.

The option to do this has value to the NEM, associated with the net present value that additional pumped storage at Snowy (referred to as 'Snowy 3.0') would have and the probability distribution of this occurring.

The option component of market benefits was determined through a consideration of possible NEM scenarios, each with a different timing and net present value for the development of Snowy 3.0. The scenario development was based on the following assumptions:

- There is a 25% probability that additional pumped storage at Snowy will be developed
- The earliest that additional pumped storage at Snowy could be developed is 2035
- The net present value to the NEM of a Snowy 3.0 development is $1,500M.

The market benefit assessment was a present value (4.55% over the period to 2074) of $150 million. This was considered a conservative estimate.

14.5 NEM operation and economics with Snowy 2.0

Snowy 2.0 would provide market benefits that reflect a reduction in capital and operating costs (mainly fuel costs) that would otherwise be needed for the production of wholesale electricity and maintaining supply reliability in the NEM.

Table 17 shows the results of the modelling. From the two scenarios modelled, the table shows the present value of the market benefit from Snowy 2.0 operation excluding the market benefit of the option, the market benefit of the option provided by Snowy 2.0, and the total. The present values were determined over the period from 1 July 2018 to 1 July 2074 at a real discount rate of 4.55%. Dollars are 31 December 2017 Australian dollars.

The market benefits excluding optionality is composed of avoided capital cost, energy arbitrage (including drought conditions) and FCAS. The variation is due to the uncertainty in the installation of batteries responding to fast start requirements and firming.

Table 17: NEM market scenario modelling results Present value $M

Scenario	Market Benefits		
	Excluding Optionality	Option for further development	Total
LRET+VRET	4,272 to 4,738	150	4,423 to 4,889
LT Commitment	6,140 to 6,643	150	6,291 to 6,793

Source: Marsden Jacob, 2017.

15. Potential price impacts of Snowy 2.0

This chapter considers how Snowy 2.0 would influence wholesale energy price outcomes and the flow-on effect this could have on the energy component of consumer prices. The uncertainty in spot and contract market dynamics meant that the modelled impact on energy prices was restricted to 10 years from the entry of Snowy 2.0.

This chapter describes the manner in which Snowy 2.0 would be expected to affect the dynamics and level of wholesale spot energy prices, and the translation of those effects to the energy component of prices paid by consumers.

15.1 Wholesale market

Spot prices in the NEM are the result of physical trading entities offering in generation (and demand) on a 5-minute basis. To assist physical traders, AEMO provides demand–volume price sensitivities as part of its pre-dispatch schedule. This provides for trading entities to identify opportunities to respond with additional generation, or when generation should be reduced.

As part of their risk management practices, the trading entities also track any contractual or retail commitments they have and that they would be required to 'cover' by operating generation. A trading entity may have a number of power stations, and in such circumstances those power stations may be offered or 'bid' in a coordinated manner (for example to supply a given level of retail demand).

The way generation is offered into the NEM is expected to change as increasing levels of intermittent generation enter the market. This is because dispatchable demand will become lower and more volatile, requiring generation, particularly base-load, to modify its operation.

In theory, clearing generation bids should reflect the cost of generation (such as coal and gas); however, in practice, it can be somewhat higher. One reason for this is that in an energy-only market (such as the NEM) generator bids reflect the capital cost of the plant and also the opportunity value of providing additional supply. This means that the spot price spread from buying and selling in the spot market may be higher than the actual spread in the generation costs involved.

Additional generation results in decreasing spot prices. Snowy 2.0 would add 2,000 MW of new dispatchable generation supply during the periods when spot prices are high and sensitive to the amount of generation that is being offered. The impact of this is more competition for wholesale supply during such periods, less spot price volatility, and prices that better reflect the costs of supply.

Additional demand results in spot prices increasing. Spot prices will increase during the periods that Snowy 2.0 is pumping. During those periods, spot prices will be less sensitive to changes in supply and demand, as pumping will occur when there is surplus and offloaded generation associated with market conditions of high intermittent generation, low demand, or both.

Further, the operating costs of coal-fired generation would reduce due to lower cycling and ramping operation associated with Snowy 2.0. It would be expected that reduced operating costs would be reflected in the prices offered for dispatch.

15.2 Retail market

In the NEM (where the product sold is homogeneous), a competitive advantage is obtained if costs can be reduced below those of competitors. Retail competition is fundamental to the efficient operation of the NEM and for competitive price outcomes to customers. Competitive and efficient prices to customers reflect efficient costs of energy procurement and related services and competitive retail margins associated with competition for retail sales.

Energy purchase costs are the main component of non-regulated costs. The percentage of total tariffs due to energy purchase costs varies by customer class: residential customers receive energy at the lowest percentage of total costs, and large industrials (with no distribution and low margins) at the highest. For the residential market, the proportion of total electricity purchase costs due to energy purchase costs is about 33%.

15.3 Modelled impact of Snowy 2.0 on spot energy prices

The modelling presented in Chapters 13 and 14 allowed the change in spot prices to be observed. Spot prices are possibly the most uncertain output of forward NEM modelling, as they are influenced by factors in addition to physical and economic outcomes. The additional factors include price spikes (of up to $14,200/MWh) that can impact prices very quickly and competition, which influences how generators offer energy to the market. For this reason, the modelled impact on spot prices is limited to the first 10 years of Snowy 2.0 operation.

The results from the modelling for Victoria and NSW for the two renewable development scenarios with and without Snowy are shown in the Figure 57 overleaf. The results show reductions in spot energy prices associated with the operation of Snowy 2.0. The spot price reductions mainly occur over the period 2025 (when Snowy 2.0 enters to about 2030). After this Vales Point has closed and Snowy 2.0 becomes “intra-marginal” to new and higher cost generation that is required due to the coal power station closures that occur.

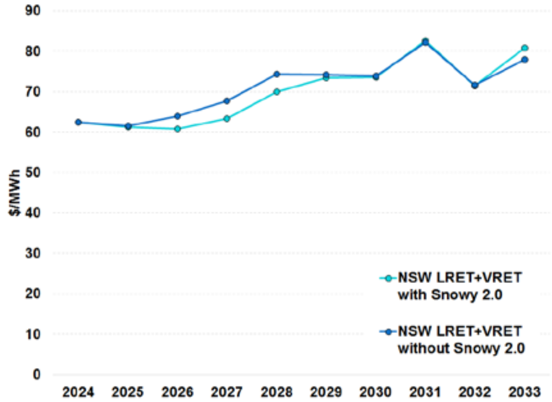
In summary the modelling showed the following:

- annual average energy spot prices reductions were variable and depended on the level of renewable generation development
- the LT Commitment scenario had an average reduction in NSW spot energy prices of $6.9/MWh (10.2% of average spot prices) while the LRET+VRET scenario had an average reduction of $1.2/MWh (1.6% of average spot prices). Based on the average of these scenarios the expected average NSW spot price reduction was $4.1/MWh, or about 5.7% of NSW spot energy prices
- the reduction in Victorian spot energy prices was lower and averaged 3.2%
- the modelling also showed that Snowy 2.0 would result in a reduction in spot price volatility. This would mean lower risk premiums for wholesale energy purchase costs, and energy prices reductions in excess of that shown through the spot market.

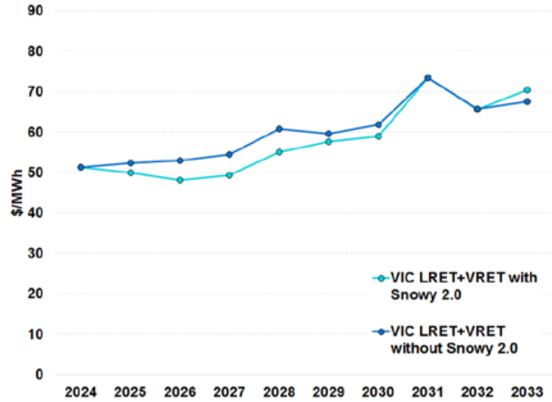
In summary, the modelling showed that the pumped storage capability provided by Snowy 2.0 would provide increasing market benefits and associated energy price reductions to NEM consumers as the level of intermittent generation increases.

Figure 57 Spot price outcomes with and without Snowy 2.0 ($/MWh)

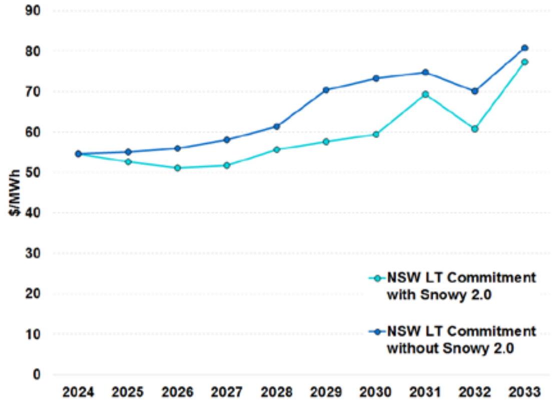
LRET+VRET scenario, NSW



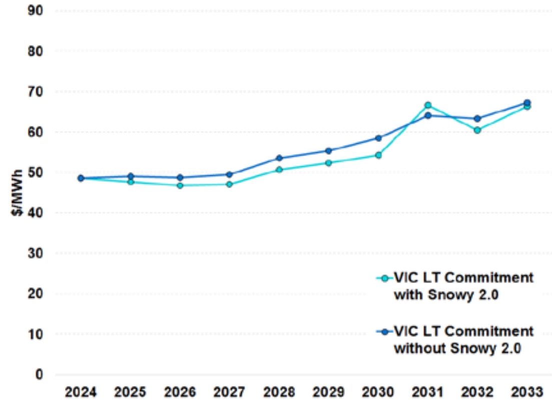
LRET+VRET scenario, Victoria



LT Commitment scenario, NSW



LT Commitment scenario, Victoria



Source: Marsden Jacob, 2017.

Appendix 1. Definition of SRMC, MRMC and LRMC

A1.1 Short run marginal costs

Short Run Marginal Cost (SRMC) is fundamental to the economics of generators in electricity markets.[91]

Generation costs can be defined as 'at generator' or 'sent out' (includes auxiliary usage). As sent out is the normal basis of costs in electricity markets, we define SRMC on the basis of sent out generation.

SRMC (sent out) is calculated as follows:

Equation 1 Short run Marginal cost formula (Sent out)

$$SRMC_{\$/MWh} = \frac{\left(Fuel_{\frac{\$}{GJ}} \times 3.6/Thermal\ efficency\right)}{(1 - Aux)} + Variable\ O\&M_{\$/MWh}$$

To convert from sent out to at the reference node[92] SRMC it is multiplied by the marginal loss factor at the location of the generator. Estimates of SRMC are highly dependent upon fuel price assumptions. As most plant operate at a thermal efficacy less than 50%, a \$1/GJ change in fuel price results in a \$7.2/MWh change in SRMC.

In the NEM, many generators would bid their generation into the market at SRMC as this represents the avoided cost of not operating the plant.

A1.2 Mid run marginal cost

Mid run marginal cost (MRMC) is defined as all costs that could be avoided (assuming no contractual obligations) if a generator unit were shut down. This includes the costs that comprise SRMC and all fixed operating costs where fixed operating costs include CAPEX, staffing, management, insurance, license fees etc.

There can be fixed costs that cannot be terminated without additional cost (or sale) such as long-term coal or gas contracts, service agreements and so on.

However, for the purpose of calculating / comparing annual costs of operating plant, the MRMC on a \$/MWh basis is defined as follows:

Equation 2 Mid run marginal cost formula (sent out)

$$MRMC_{\$/MWh} = SRMC_{\$/MWh} + \frac{Fixed\ O\&M_{\frac{\$}{MW}/Year}}{Capacity\ Factor\ \times 8760}$$

As can be seen, the calculation of MRMC on a \$/MWh basis requires an estimate of the capacity factor of operation, which can be quite uncertain. On a \$/MWh basis, peaking plants can have high MRMCs as the

91 SRMC is a fundamental in the economics of production assets in all industries.

92 This is \$/MWh of generation that 'reaches' the regional reference node.

annual costs are spread over a small number of operating hours.

A1.3 Long run marginal cost

LRMC[93] can be defined as the change in total costs that results from an increment or decrement in electricity consumption in the future. LRMC can be applied to a single generating plant or a portfolio of generating units.

LRMC can be calculated in a number of ways. For example, LRMC can be calculated on the costs of constructing and operating a new generation plant over its projected life. This approach can be used to calculate the levelised cost of new-entrant plant.

Alternatively, it can be calculated as the difference in the Net Present Value (NPV) of two optimal generation development programs over a period of 20–30 years. Each of the optimal generation programs utilises existing generation plant, committed developments and the most efficient new generation entry.

The first generation installation is done under a base case forecast and the second under an alternative forecast that has a defined increment of load added. The LRMC is the change in NPV of costs divided by the change in NPV of load. This is a long run marginal cost basis as it determines the marginal increase in costs associated with meeting a marginal increase in demand with all factors of production variable.

LRMC costs include fuel costs, operations and maintenance and the capital costs of constructing a generation facility. It does not include costs that are unrelated to the investment decision in the plant (such as head office costs).

93 Intelligent Energy Systems 2004, *The long run marginal cost of electricity generation in New South Wales*, February 2004, https://www.ipart.nsw.gov.au/files/e27092d2-0d1b-46f9-ac88-9f6d00929c1e/Pubvers_Rev_Reg_Ret_IES010304.pdf [8 November 2017].

Appendix 2. The existing Snowy Hydro system

A2.1 Description

The Snowy Mountains Scheme is a combined hydroelectricity and irrigation scheme developed in the 1950's which is situated in Snowy Mountains in NSW approximately mid-way between Sydney and Melbourne.

The physical description of the scheme is as follows:

- The highest and main reservoir is Lake Eucumbene. The storage of this reservoir (4367 GL) provides for multiple years of inflows to be stored. This provides drought protection for both electricity production and irrigation
- Water from Lake Eucumbene can be directed to either the Tumut or Murray side power stations. The water from the Tumut side power stations (T1, T2 and T3) flows to the Tumut river (and then to the Murray River) while water from the Murray side power stations (M1 and M2) flows to the Murray River and Hume reservoir
- Lake Jindabyne is slightly lower and substantially smaller (389 GL) than Lake Eucumbene. Pumping at Jindabyne is undertaken to transport water to Island Bend reservoir from where it can be used in the Murray power stations
- The highest lake is Lake Tantangara (231 GL) which provides water Lake Eucumbene (which can be used in either the Tumut or Murray side power stations).

The key attributes of the Snowy hydro-electric scheme as a whole are as follows:

- total capacity: 3,740 MW
- annual average generation: 4,500 GWh
- pumped storage at Tumut 3 Power Station: 600 MW
- provides frequency control services.

Table 18 presents the details of the power stations on the Tumut and Murray sides of the scheme.

Table 18: Current Snowy Hydro scheme generators

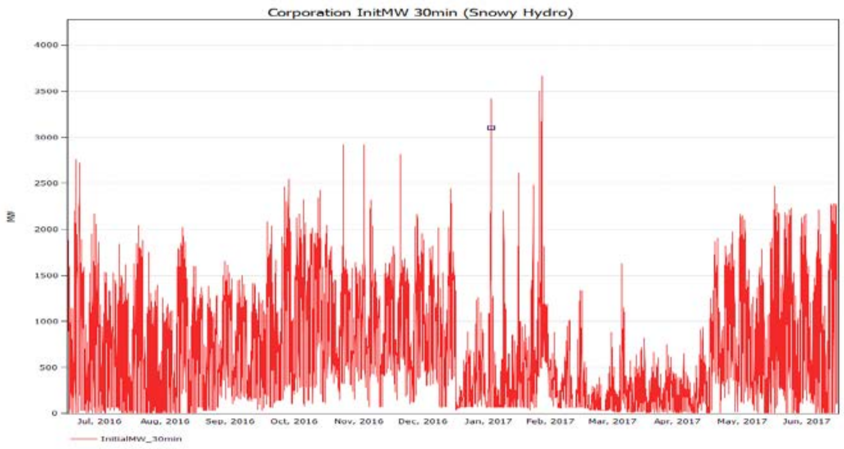
	Station	Number of units	Unit size	Total MW
Tumut side	Tumut 1	4	80	320
	Tumut 2	4	70	280
	Tumut 3	6	250	1500
	Blowering	1	80	80
			Total	2180
Murray side	Guthega	2	30	60
	Murray 1	10	95	950
	Murray 2	4	137.5	550
			Total	1560

Source: Marsden Jacob, 2017

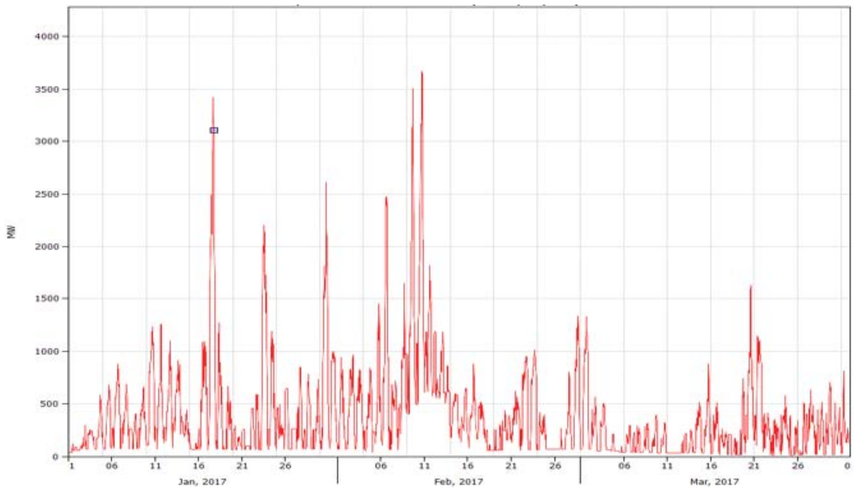
A2.2 Historical operation

A sample of the historical operation of Snowy Hydro is presented in Figure 58, which shows the 30-minute generation levels over the periods indicated. This is shown to illustrate the continuous need for Snowy generation and the uncertain and variable nature of this need.

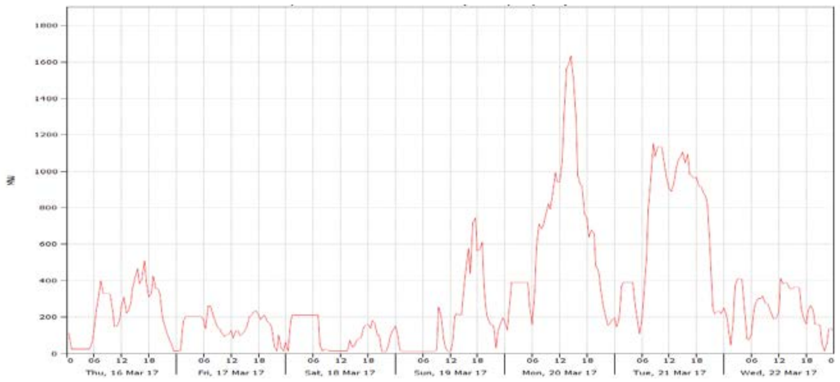
Figure 58: Snowy Hydro generation—total 30-minute generation level (MW)



July 2016 – June 2017



January – March 2017

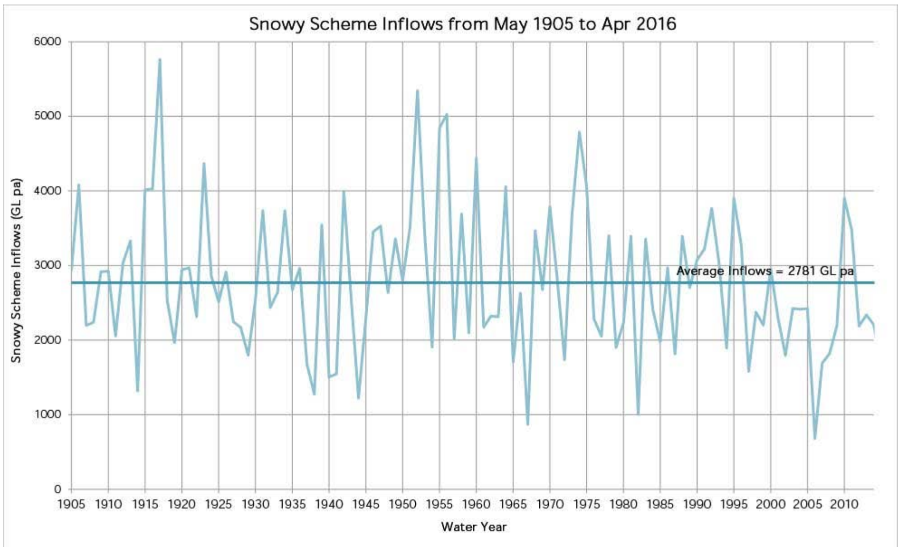


Week commencing
16 March 2017

Source: AEMO data; NEO Data Viewer.

On a total annual generation basis, the amount of generation is influenced by the amount of water in storage, water inflows to the scheme, and irrigation requirements. Water inflows to the smaller ponds does result in 'must use' or spill while water inflows to Lake Eucumbene can be stored across years. The variable nature of water inflows is shown in Figure 59, which shows the total annual water inflows to the total scheme since 1905 (calculated based on recorded water inflows).

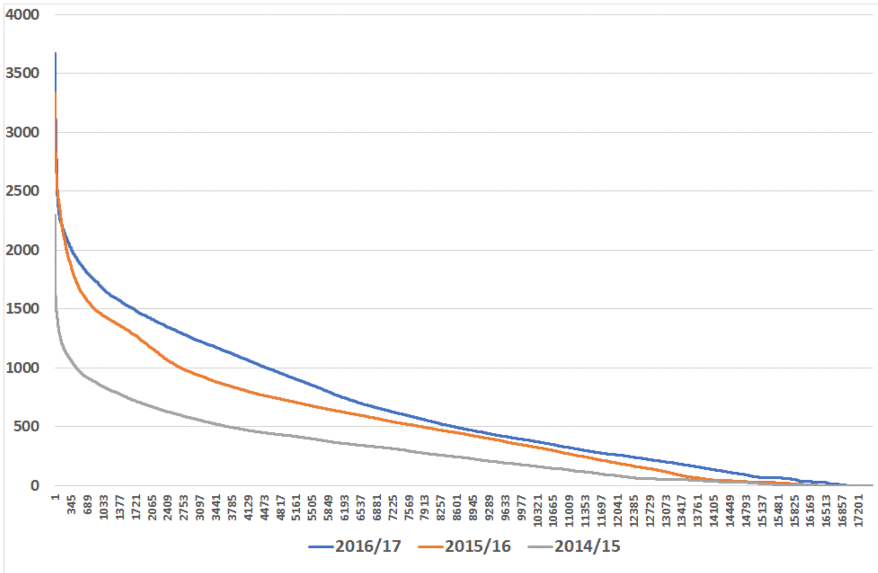
Figure 59: Snowy water inflows to total scheme (GL/year)



Source: Inflows data from Snowy Hydro, *Inflows*, no date, www.snowyhydro.com.au/our-energy/water/inflows/ [8 November 2017].

Over a year the profile of generation can be conveniently presented in a 'generation duration curve'. This is the 30-minute generation levels in a year ordered from highest to lowest and then graphed. This is shown in Figure 60, which plots the Snowy generation duration curves for the years three years financial 2014–15, 2015–16, 2016–17.

Figure 60: Snowy generation duration curves, 2014–15, 2015–16 and 2016–17



Source: AEMO data; Marsden Jacob, 2017

While these curves do not show daily variability, they show the amount of time Snowy provided different levels of capacity support. It is also noted that the design of the LRET schemes which rewards large-scale generation certificates above baseline operation incentives Snowy to vary annual generation below and above this baseline.

Appendix 3. Ancillary services

Ancillary services assist the AEMO to manage the power system safely, securely and reliability. The services delivered keep the system operating within defined technical limits including those related to frequency control and reserve capacity.

A3.1 Frequency control ancillary services

Markets for FCAS operate in a similar manner to the wholesale electricity spot market with generators bidding into the market and being paid for services as the prevailing market price. At any point in time, close to fifty cycles (or 50 Hz) are required by the NEM frequency standards.[94]

Two types of frequency controls are used:

- ***Regulation frequency control*** is provided by generators on the Automatic generation control system, which allows the AEMO to continually monitor the system frequency and send control signals out to generators providing regulation such that frequency is maintained within the normal operating limits of 49.85 Hz to 50.15 Hz.
- ***Contingency frequency control*** refers to the requirement under the NEM frequency standards that, following a credible contingency event, the AEMO must ensure the frequency deviation remains within the contingency band and is returned to the normal operating band within five minutes. Contingency frequency control services are provided by technologies that can locally detect the frequency deviation and respond in a manner that corrects the frequency. Examples listed in the AEMO's *Guide to ancillary services in the National Electricity Market* include:[95]
  - *generator governor response:* where the generator governor reacts to the frequency deviation by opening or closing the turbine steam valve and altering the MW output of the set accordingly
  - *load shedding:* where a load can be quickly disconnected from the electrical system (can act to correct a low frequency only)
  - *rapid generation:* where a frequency relay will detect a low frequency and correspondingly start a fast generator (can act to correct a low frequency only)
  - *rapid unit unloading:* where a frequency relay will detect a high frequency and correspondingly reduce a generator output (can act to correct a high frequency only).

The eight markets for FCAS are summarised below with the two types of frequency control indicated.

Table 19: Summary of FCAS markets

Type of frequency control	FCAS market	Description
Regulation	Regulation Raise	Regulation service used to correct a minor drop in frequency.
	Regulation Lower	Regulation service used to correct a minor rise in frequency
Contingency	Fast Raise (6 Second Raise)	6-second response to arrest a major drop in frequency following a contingency event.

94 AEMO, *Guide to ancillary services in the National Electricity Market*, April 2015, p. 4, www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf [8 November 2017].

95 AEMO, Guide to ancillary services in the National Electricity Market, p. 7.

Type of frequency control	FCAS market	Description
	Fast Lower (6 Second Lower)	6-second response to arrest a major rise in frequency following a contingency event.
	Slow Raise (60 Second Raise)	60-second response to stabilise frequency following a major drop in frequency.
	Slow Lower (60 Second Lower)	60-second response to stabilise frequency following a major rise in frequency.
	Delayed Raise (5 Minute Raise)	5-minute response to recover frequency to the normal operating band following a major drop in frequency.
	Delayed Lower (5 Minute Lower)	5-minute response to recover frequency to the normal operating band following a major rise in frequency.

Source: AEMO, Guide to ancillary services in the National Electricity Market, p. 8

A3.2 Network support and control ancillary services

There are three categories of NSCAS:[96]

- *Voltage control ancillary services* are used to control the voltage at different points of the electrical network to within the prescribed standards. One method of controlling voltages on the system is through the dispatch of voltage control ancillary services. Under these ancillary services, generators absorb or generate reactive power from or onto the electricity grid and control the local voltage accordingly. The voltage control ancillary services can be further categorised as follows:
  - synchronous condenser: a generating unit that can generate or absorb reactive power while not generating energy in the market
  - static reactive plant: equipment such as capacitors or reactors that can supply or absorb reactive power.
- *Network loading control ancillary services* control the power flow on network elements to within the physical limitations of those elements. These services are used by the AEMO to control the flow on inter-connectors to within the short term limits. When power flow issues arise, the service can be controlled though the use of automatic generation control (the same technology that is used for regulation frequency control) or through load shedding.
- *Transient and oscillatory stability ancillary services* are used to maintain transient and oscillatory stability within the power system following major power system events. These services control and fast-regulate the network voltage, increase the inertia of rotating mass connected to the power system or rapidly increase/reduce load connected to the power system. The service is used when faults such as short circuits or malfunctioning equipment occur that cause a sharp transient 'spike' in power flows. In the absence of the transient and oscillatory stability ancillary services, a spike in power flows can cause damage to equipment throughout the network.

A3.3 System restart ancillary services

System restart ancillary services (SRAS) are reserved for contingency situations in which there has been a complete or partial system blackout and the electrical system must be restarted. SRAS can be provided two separate technologies:[97]

- *general restart source:* a generator that can start and supply energy to the transmission grid without any external source of supply

96 AEMO, Guide to ancillary services in the National Electricity Market, April 2015, p. 13.

97 AEMO, Guide to ancillary services in the National Electricity Market, p. 13.

- *trip to house load:* a generator that can, on sensing a system failure, fold back onto its own internal load and continue to generate until the AEMO is able to use it to restart the system.

The payments for both NSCAS and SRAS are provided to the market under long term ancillary service contracts negotiated between the AEMO (on behalf of the market) and the participant providing the service. These services are paid for through a mixture of:

- enablement payments: made only when the service is specifically enabled (applicable to static reactive plant providing voltage control ancillary services only)
- availability payments: made for every trading interval that the service is available (applicable to static reactive generators providing voltage control ancillary services and to generators providing SRAS).
- testing payments: made for costs incurred for annual testing of service (applicable to synchronous condenser generators providing voltage control ancillary services and to generators providing SRAS)
- usage payments: made for every trading interval when the service is used (applicable to generators providing SRAS only).[98]

98 AEMO, Guide to ancillary services in the National Electricity Market, p. 14.

Appendix 4 Base-load generation economics under increasing variable demand

This section illustrates the degree to which base-load coal generation economics changes when the demand profile being supplied requires generation to operate at lower capacity factors.

To do this Figure 61 and Figure 62 below present two cases of base-load generation supplying two different demand profiles – the first being flat and the second being variable and uncertain. For each case the figure shows the level of generation reserves, the level of installed generation which is assumed to be operating, and the level of unserved energy that results from a generator unit outage.

This model is then used to show that the average cost of generation supplied ($/MWh) increases due to two issues:

- the demand profile becomes more variable (requiring generation to operate at lower capacity factor)
- there is a requirement to maintain generation reserves for provide the required level of supply reliability.

Table 20 shows six cases distinguished by the load factor of demand supplied, the level of demand uncertainty, and the level of generation reserves (installed generation capacity in excess of the maximum demand). All cases have the common assumptions of maximum demand, 10 generator units of the same size installed, and the same generator costs. These costs are a capacity cost of $3000/kW (corresponding to $31/MWh assuming 100% capacity factor operation) and fuel and VOM costs totalling $35/MWh, giving a total cost of $66/MWh (at 100% capacity factor).

Also shown is the unserved energy that would result, on average, from the reserve marginal assumption and load shape.

The variable demand profile could equally be considered at the customer demand profile less the generation by intermittent generation. This 'residual demand' is that required to be supplied by dispatchable generation.

As shown in the table, the impact of the demand load factor and reserve margin on the cost of generation supplied is substantial. It increases from $66/MWh to $118/MWh under 50% load factor, demand uncertainty and a typical reserve margin of 20%.

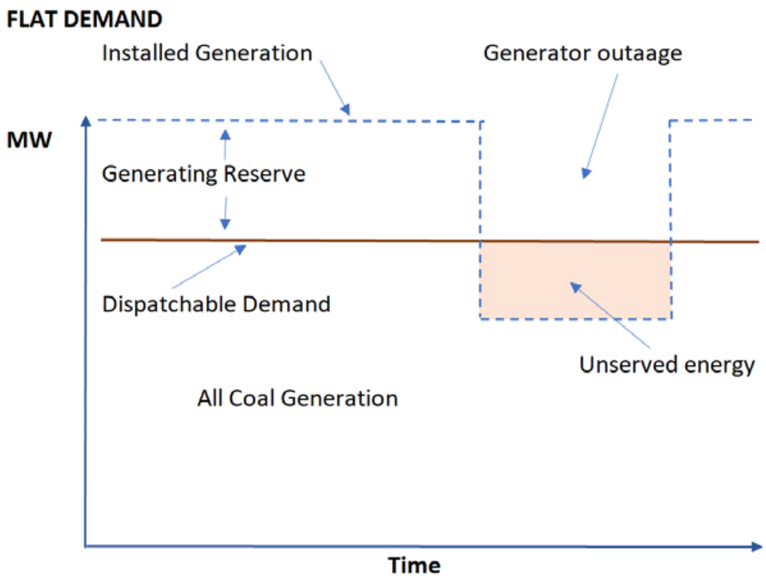
Table 20: Costs of base-load generation, illustrative cases ($/MWh supplied)

Case	Demand		Generation					USE
	Load Factor	Dem uncertainty	Res Margin	Cap Fact	Ave HR	O&M	Ave Gen cost	% USE
1	100%	0%	0	100%	10	6	66.0	7.25%
2	100%	0%	20%	83%	10.25	6	72.8	0.15%
3	70%	0%	0%	70%	10.5	6	80.4	0.145%
4	70%	0%	20%	58%	11	6	90.4	0.002%
5	50%	0%	20%	42%	11.5	6	112.5	0.002%
6	50%	25%	20%	42%	12	10	118.0	0.002%

Source: Marsden Jacob, 2017.

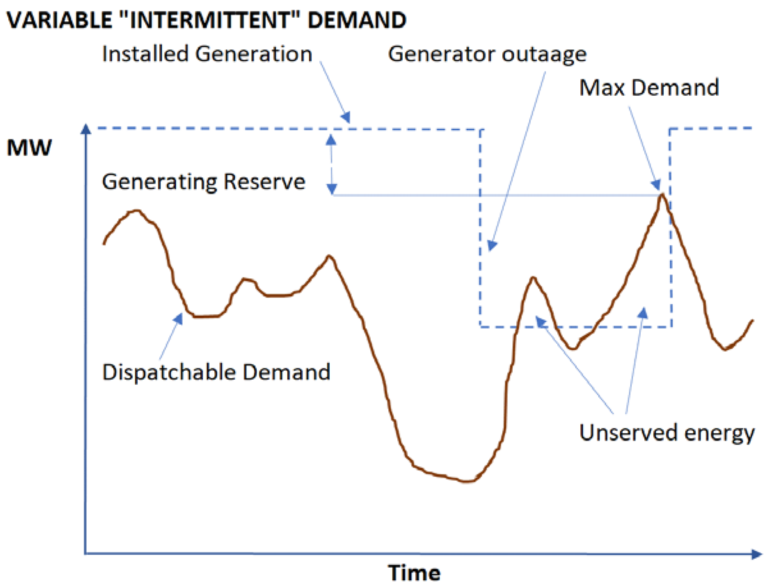
This also illustrates that reported generation costs can be misleading in relation to the costs per MWh of energy actually supplied to consumers when demand variability and reserve margins are accounted for.

Figure 61: Illustration of base-load generation supplying different demand profiles



Source: Marsden Jacob, 2017.

Figure 62: Variable intermittent demand



Source: Marsden Jacob, 2017.

Appendix 5. Interpreting renewable generation targets

The development of a renewable generation development profiles requires a translation of the percentage supplied by renewable generation to actual levels of renewable generation.

In simple terms, the ratio of renewable generation divided by total electricity demand supplied by all generation. In the NEM the generation classifications are scheduled generation, semi-scheduled generation, rooftop PV, non-scheduled generation.

However, it is likely that the calculation of the percentage of energy supplied by renewable generation will account for schemes in existence such as the LRET.

The calculation of the percentage of energy supplied by renewable generation in the LRET is given by the following:

$$Renewable\ Gen_{\%} = \frac{Large\ scale\ Renewable\ Gen_{GWh} + PV_{GWh} + Pre\ 1997\ RG_{GWh}}{Australian\ Electrcity\ Demand_{GWh}} \times 100$$

Assuming this would be the approach referred to in policy, the translation of the percentage of generation supplied by renewable generation to renewable generation requires that the components which determine this are assessed across all the Australian power systems in each future year. These are:

- pre-existing (1997) renewable generation (which has baselines at their long-term average)
- rooftop PV
- large-scale renewable generation (scheduled and semi-scheduled generation), where this needs to account for auxiliary load, transmission losses, and non-accredited renewable generation (see box below)
- the level of native electricity demand in the year. In the NEM native electricity demand is scheduled demand plus rooftop PV plus non-scheduled generation.

While this translation may appear to be straight forward it has proven to be difficult. This is due to estimating issues such as the creation of renewable generation above baselines, transmission losses, and non-scheduled generation (most of which the level of generation is not available).

Table 21 presents the projection of electricity demand and the level of renewable generation projected in the electricity systems across Australia. This illustrates that the NEM and Wholesale Electricity Market in Western Australia make up over 97% of the total electricity subject to renewable generation policy.

Box 1: Renewable Energy (Electricity) Regulations 2001 dated 4 November 2014

Clause 14 says (in summary form below)

The amount of electricity generated by an accredited power station in a year is:

TLEG – (FSL + AUX + (DLEG x (1 – MLF)))

- TLEG is the total amount of electricity, in MWh, generated by the power station in the year, as measured at all generator terminals of the power station in the year.
- FSL is the amount (if any) of electricity, in MWh, generated by the power station in the year using energy sources that are not eligible energy sources.
- AUX is the auxiliary loss, in MWh, for the power station for the year.
- DLEG is the amount of electricity, in MWh, transmitted or distributed by the power station in the year.

Table 21: Estimated Australian electricity demand in 2020, net of auxiliary load and transmission losses (GWh)

	Scheduled	Non-scheduled	Rooftop PV	Transmission losses	Total
NEM	184,303	3,416	11,188	4,984	193,923
Western Australia—SWIS	20,852	387[a]	1,156	564[a]	21,830
Western Australia—NWIS	1183		11[a]	32[a]	1,162
Northern Territory	2215		42	60[a]	2,198
Mt Isa region	2239			61[a]	2,178
Total	210,793	3,803	12,397	5,700	221,291

a. Estimated by Marsden Jacob.

Source: Marsden Jacob, 2017.

The approach used in this report to translate the percentage of energy supplied by renewable generation to renewable generation output was as follows:

- Assume the NEM and Wholesale Electricity Market develop renewable generation in proportion to their respective demand levels.

In the NEM, the percentage of renewable generation is based on the ratio of renewable generation (large-scale plus small-scale) divided by total electricity demand supplied by all generation (scheduled generation, semi-scheduled generation, rooftop PV, non-scheduled generation).

Appendix 6. Cost of firming intermittent generation

The cost of providing ‘dispatchable capacity’ has been recognised in this study as fundamental to energy procurement risk. This is a key factor in the economics and investment profile of battery development with and without Snowy 2.0.

This appendix derives the cost of capacity provided by renewables and storage and compares it to non-renewable capacity.

A6.1 Cost calculation

Battery costs consist of:

- storage (kWh): costs are proportional to the level of storage. This cost is expected to reduce by 30% by 2032
- inverter: limits the capacity (kW) the battery system can deliver. This cost is expected to decrease. The assumption is a 15% reduction by 2032
- connection. This is expected to remain the same in real terms.

A battery installation can have different storage levels (MWh) for a given capacity (MW). There are many proposals to combine a solar installation and battery system to provide firm capacity.

To assess the costs, a calculation was done on the basis of matching a battery system to a solar installation that provides (on average) 4 MWh of energy per day. Given that a battery can have different storage levels, three cases were considered:

- Case 1: The battery has a level of storage equal to the amount of a solar facility produces in a day. The MW capacity of the battery is such that, fully charged battery and discharging at maximum capacity, it would operate for 4 hours.
- Case 2: Storage is increased to 8 hours and the capacity unchanged.
- Case 3: Storage is increased to 12 hours and the capacity unchanged.

These cases represent an increasing level of firmness, as increased storage allows solar energy produced in one day to be used in subsequent days. The value of this additional storage is not discussed here (only the cost of provision).

The calculation of the $ per year (and corresponding $/MWh) for a solar installation that produces 4 MWh per day (on average) combined with different levels of storage is shown in Table 22. The $/MWh shown in the table are based on 4 MWh of solar per day (1,460 GWh per year) at various level of storage (MWh).

Table 22: Calculation of battery storage costs

2018	Per Unit Cost			$ /year		
	$/kW	$/MW/Year	$/MWh (4 Hours/day)	4 MWh/day	8 MWh/day	12 MWh/day
SOLAR (4 MWh/day)						
LCOE			$64	$93,440		
BATTERY (1 MW)						
Capital cost $/kW for 4 hours storage	$1,800	$295,095	$202	$295,095	$590,190	$885,285
Inverter $/kW	$280	$39,866	$27	$39,866	$39,866	$39,866
Conenction $/kW	$330	$46,985	$32	$46,985	$46,985	$46,985
Total for specified storage		$381,945	$262	$381,945	$677,040	$972,135
SOLAR (4 MWh/day) + STORAGE						
Solar 4 MWh/day + Battery				$475,385	$770,480	$1,065,575
				$/MWh	**$/MWh**	**$/MWh**
SOLAR (4 MWh/day) + STORAGE $/MWh				**4 MWh/day**	**8 MWh/day**	**12 MWh/day**
Solar 4 MWh/day + Battery				$326	$528	$730

2032	Per Unit Cost			$ /year		
	$/kW	$/MW/Year	$/MWh (4 Hours/day)	4 MWh/day	8 MWh/day	12 MWh/day
SOLAR (4 MWh/day)						
LCOE			$35	$51,100		
BATTERY (1 MW)						
Capital cost $/kW for 4 hours storage	$1,250	$186,133	$127	$186,133	$372,266	$558,399
Inverter $/kW	$238	$33,886	$23	$33,886	$33,886	$33,886
Conenction $/kW	$330	$46,985	$32	$46,985	$46,985	$46,985
Total for specified storage		$267,003	$183	$267,003	$453,136	$639,269
SOLAR (4 MWh/day) + STORAGE						
Solar 4 MWh/day + Battery				$318,103	$504,236	$690,369
				$/MWh	**$/MWh**	**$/MWh**
SOLAR (4 MWh/day) + STORAGE $/MWh				**4 MWh/day**	**8 MWh/day**	**12 MWh/day**
Solar 4 MWh/day + Battery				$218	$345	$473

Note: Snowy costs are based on generic pump storage costs only.

Source: Marsden Jacob, 2017.

Assumptions not shown are:

- a discount rate of 7% real for battery systems and Snowy 2.0
- batteries:
  - economic life 10 years
  - developed in 2018: degradation of 30% by year 10
  - developed in 2032: degradation of 10% by year 10.

A6.2 Gas-fired generation as a firming service

Gas-fired generation provides a very different firming service from storage. In fact, it should be considered as simply gas generation, as it does not provide for excess renewable generation to be used.

Table 23 presents the cost of gas generation providing firming capacity to support intermittent generation.

Allowing for inefficient use associated with the need to have plant operating when it is not required, Table 23 shows CCGT plant has higher costs than Snowy 2.0, but that OCGT plant close has costs close to Snowy 2.0 (on the assumptions used).

Table 23: Costs of gas generation for firm capacity

Costs	Capital		Fuel and Ops		
	$/kW	$/MW/year	$/GJ	Heat Rate	VOM
OCGT	1286	$103,634	11	9.6	10.3
CCGT	1590	$128,132	9	7.3	7

	Hours/day	$/MWh Capital	$/MWh SRMC	$/MWh Total	Including non necessary operation $/MWh	
OCGT	4	$71	$116	$187	$196	High emissions
CCGT	4	$88	$73	$160	$241	Moderate emission

Note: A requirement to have CCGT plant already running would add additional costs (estimated as more than 50%). There would be a small amount of inefficient OCGT use (estimated at 5%).

Source: Marsden Jacob, 2017.

A6.3 Observations

Battery storage that equals the daily energy production of solar provides limited ability to control generation as required. Twelve hours provides more on the day, but does not address the issue of consecutive days of no sun (or wind). For this reason, even a 12 MWh storage associated with a 4 MWh/day solar installation is considered insufficient to provide reliable capacity.

Appendix 7. Market Benefits

The appendix presents the definition of market benefits as defined by the AER in the paper "Final, Regulatory investment test for transmission, June 2010.

In that paper the AER state:

> "The purpose of the RIT-T, as set out at clause 5.6.5B(b) of the Electricity Rules, is to identify the *credible option* that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the *market* (the *preferred option*). For the avoidance of doubt, a *preferred option* may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the *identified need* is for *reliability corrective action*."

The market benefits are described in paragraphs 4, 5 and 6 of the abovementioned paper. These paragraphs are reproduced below.

Market benefits

(4) Market benefit must be:

(a) the present value of the benefits of a credible option calculated by (i) comparing, for each relevant reasonable scenario:

(A) the state of the world with the credible option in place to

(B) the state of the world in the base case,

and (ii) weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring.

Note: Where a transmission network service provider has no material evidence for assigning a higher probability for one reasonable scenario over another, all reasonable scenarios may be weighted equally.

(b) a benefit to those who consume, produce and transport electricity in the market, that is, the change in producer plus consumer surplus.

(5) Subject to paragraph 7 and 8, the market benefit must include the following benefits:

(a) changes in fuel consumption arising through different patterns of generation dispatch

(b) changes in voluntary load curtailment

(c) changes in involuntary load shedding, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers

(d) changes in costs for parties, other than the transmission network service provider, due to:

(i) differences in the timing of new plant

(ii) differences in capital costs; and

(iii) differences in the operational and maintenance costs;

(e) differences in the timing of transmission investment

(f) changes in network losses

(g) changes in ancillary services costs

(h) competition benefits being net changes in market benefit arising from the impact of the credible option on participant bidding behaviour

(i) any additional option value (meaning any option value that has not already been included in other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market

(j) negative of any penalty paid or payable (meaning the penalty price multiplied by the shortfall) for not meeting the renewable energy target, grossed-up if not tax deductible to its value if it were deductible; and

(k) other benefits that the transmission network service provider determines to be relevant and are agreed to by the AER in writing before the project specification consultation report is made available to other parties.

(6) Market benefit must not:

(a) include the transfer of surplus between consumers and producers;

(b) include the costs which meet the criteria in paragraph 2; or

(c) include competition benefits or any additional option value where they have already been accounted for in other elements of the market benefit.