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There is significant uncertainty and increasing risk to the National Electricity Market (***NEM***) as the existing thermal fleet retires and is replaced by Variable Renewable Energy (***VRE***), gas generation and crucially, storage. The future evolution of the NEM and the dynamics of energy arbitrage mean that the value arising from Snowy 2.0 is subject to and sensitive to many factors.

1.1 Introduction

There is significant uncertainty and increasing risk to the NEM as the existing thermal fleet retires and is replaced by VRE, gas generation and crucially, storage. These risks include the variability of energy production from VRE over both short and long-time scales, coal plant performance, availability of gas plant, and demand outlook. The future evolution of the NEM and the dynamics of energy arbitrage mean that the value arising from Snowy 2.0 is subject to and sensitive to many factors. This chapter focuses on the macro assumptions that underpin those drivers of value and presents a qualitative overview of the transformation of the NEM over the next 50+ years.

1.2 Activities undertaken

Snowy Hydro engaged independent market experts Marsden Jacob Associates (***MJA***) as a third-party specialist economic modelling firm with comprehensive experience in the NEM. Multiple stages of work have been undertaken for both the Feasibility Study and for Final Investment Decision (***FID***). This chapter focuses upon the analyses undertaken by both Snowy Hydro and MJA, which concern macro influences on Snowy Hydro revenue. The full MJA scope is explored in *Supporting Chapter Five - Market modelling*.

1.3 Macro modelling assumptions

Snowy Hydro and MJA reviewed a number of information sources, including the NEM outlook, Australian Energy Market Operator (***AEMO***)'s underlying assumptions, commissioned reports and State and Federal policy. A base set of assumptions was developed from this review.

The key macro assumptions are:

1. **Demand growth** - the base case demand outlook was based on the more conservative AEMO's Electricity State of Opportunities (***ESOO)*** 2017. There is potential for demand to be higher than projected;
2. **Coal generator closure profile** - the profile is as presented in the AEMO Integrated System Plan (***ISP***),[1] with all coal plant closing after 50 years of service except for Loy Yang A and Loy Yang B after 60 years of service. Notably, all existing coal plant would have closed by 2060;
3. **Existing coal generator performance** - ramp rates (as estimated within currently observed and bid parameters) and forced outage rates will increase in line with plant age. Observed minimum generation (mingen) levels were used, with lower levels considered through sensitivity analysis;
4. **Transmission development** - The AEMO ISP (with an adjustment to bring forward the southern loop by ten years) was used as the basis for long-range development;
5. **Supply-side options and costs** - cost of conventional thermal plant not expected to decrease, solar and wind generation to continue to decrease, battery costs based on 4-hours storage;
6. **Gas and coal costs** - gas reserve outlook (AEMO, supported by analysis by EnergyQuest) is that substantial new reserves are required and that these will likely be at higher cost;

[1] (Australian Energy Market Operator Limited 2018).

7. **Behind-the-meter response and costs** - rooftop photovoltaic (***PV***), behind-the-meter batteries, and demand-side management consistent with AEMO ISP, no storage contribution from electric vehicles (***EV***);
8. **EV** - slow take-up until mid-2020s, then accelerating take-up to saturation in 2055-60;
9. **Emissions and renewable energy policy** - the base case assumption is no emissions limits;
10. **Renewable energy schemes** - Large-scale Generation Certificate (***LGC***) prices are likely to collapse in the early 2020s, due to increase in eligible generation. Victorian Renewable Energy Targets (***VRET***) and QLD Renewable Energy Targets (***QRET***) are assumed to be met;
11. **Marginal Loss Factors (*MLF*)** - MLFs are substantially decreasing for new renewable generators, but the base base is based on current MLFs;[2] and
12. **Ancillary and other services** - Frequency Control Ancillary Services (***FCAS***) prices are expected to reduce due to increased supply from batteries and the demand-side. Energy adequacy (available reserve) may become a contracted service. The base case assumed that Snowy 1.0 FCAS revenues would remain the same, Snowy 2.0 would access 50% more share of the 5-minute market, and there would be no revenue arising from an energy reserve service.

1.4 NEM transformation

The NEM is undergoing a transformation, which is considered across three periods:

1. **2018 to 2025** - Pre-Snowy 2.0/Increasing VRE;
2. **2025 to 2047** - Post-Snowy 2.0/Transition to near-all VRE; and
3. **2048 to 2075** - Near-all VRE.

A summary of these periods is given in Table 1 below.

Before Snowy 2.0	After Snowy 2.0 Enters	
2018 – 2025: Increasing VRE	**2025 – 2047: Transition to near-all VRE**	**2048 to 2075: Near-all VRE**
1. Increasing renewable generation in VIC and QLD 2. Liddell closes (in NSW) requiring (according to AEMO) 1000 megawatts (***MW***) of replacement firm capacity into NSW. In 2022 this is provided by gas generation, battery, new VRE and increased interconnection to NSW	1. Major transition upgrades in 2025 (Kerang link and Bannaby link) provide increased support between SA-VIC-NSW. SA/VIC/NSW have the characteristics of a single region. 2. LRET and VRET have been completed. QRET has continuing VRE development in QLD. 3. Vales Point projected to close in 2028.	1. NEM moves to a system dominated by VRE and firming largely provided by storage and gas plant. 2. Value of storage increases due to the increasing amount if VRE required to be stored for later use.

[2] MLFs are electrical transmission losses across the five regions in the NEM – QLD, New South Wales (NSW), VIC, South Australia, and Tasmania. AEMO publishes this information annually by 1 April as required by clause 3.6 of the National Electricity Rules (***NER***). The MLF for a connection point represents the marginal electrical transmission losses in electrical power flow between that connection point and the regional reference node (***RRN***) for the region in which the connection point is located.

3. SA-NSW interconnector (Riverlink) developed in 2024 4. Gas market remains tight 5. Coal plant operation starting to change 6. Reduced retail margins and tighter wholesale energy purchase risk management.	4. Continuing large-scale VRE development reflects coal plant closures and a 2030 renewable or emissions policy. 5. All coal plant closes in NSW by 2044. 6. Post mid-2030's NEM energy surplus is reducing and firming capacity is increasingly required – storage and gas peaking 7. Increase in load following contracts	3. Likely that the transmission interconnection will be further developed 4. Increasing periods of excess VRE result in spot prices reducing. 5. Price spread for S2.0 reflects low but costs and gas type sell prices

Table 1: NEM Development Periods

2 Activities undertaken

Snowy Hydro engaged MJA as a third-party specialist economic modelling firm with comprehensive experience in the NEM. Multiple stages of work have been undertaken for both the Feasibility study and for Final Investment Decision (***FID***). This chapter focuses upon the analyses undertaken by both Snowy Hydro and MJA, which concern macro influences on Snowy Hydro revenue. The full MJA scope is explored in *Supporting Chapter Five.*

3 Macro modelling assumptions

3.1 General

The development of the scenarios and modelling approach began with a review of the NEM outlook and underlying assumptions developed by AEMO as part of their information provision and planning roles, announcements by relevant parties, State and Federal policy, and current NEM outcome trends.

From this review a set of 'base assumptions' were developed. The base assumptions were developed:

1. From the publications by AEMO:
    a. Electricity State of Opportunities 2018 (***ESOO*** 2018) published August 2018, as well as the 2017 projections;
    b. ISP published July 2018; and
    c. National Electricity Forecasting Report 2017 Update published March 2018
2. Gas projection from Energy Quest and MJA assessment;
3. Coal plant reliability and flexibility parameters from Aurecon; and
4. Assessments by MJA.

A summary of the key assumptions is presented in the sections that follow.

3.2 Renewable generation development

3.2.1 Overview

This section develops a renewable generation development outlook based on announced or intended policy and economics.

3.2.2 Policy objectives

The announced policies and targets by Commonwealth and State governments are summarised in Table 2. Table 3 shows the renewable projects they have signalled that are intending to be developed.

These tables provide an indication of the quantum of distributed and large-scale renewable generation development that is intended. In relation to this the following are noted:

1. The amount of renewable projects either committed or intending to be developed is more than that required to satisfy the LRET. If all of this renewable generation entered under the LRET then the level of oversupply would in all probability result in LGC prices collapsing in the early 2020s;
2. The coalition have a policy that electricity sector emissions do not exceed 26% of 2005 levels. They are proposing that this level not be changed and that no mechanism be introduced pre-2030 to satisfy the 26% emissions reduction;
3. The coalition are silent on post-2030 emissions policy;
4. While the coalition abandoned the National Energy Guarantee (***NEG***) there appears to be some consensus that the reliability obligation, in some form, be completed and implemented;
5. The opposition have a policy of having NEM emissions limited to 45% below 2005 levels by 2030 and a renewable energy target of 50% by 2030;
6. The opposition have indicated that NEG-type arrangements would be considered for implementing the 45% emissions reduction policy;
7. Small-scale renewable presents a significant proportion of renewable development;
8. The State-based targets are a response to the Federal LRET scheme not providing for continuing renewable generation development post-2020:
    a. VIC announced on 23 August 2017 it would legislate a 40% RET by 2025;[3]
    b. QLD has not yet legislated a State base target and has not indicated when this might occur; and
    c. The SA targets have largely been met through the LRET as a result of SA being a preferred location for wind generation.

[3] See, eg (Willingham 2017).

Federal/State scheme	Energy gigawatt-hour (*GWh*) target	Investment required (in excess of the LRET) (MW)
Federal - LRET	33,000 GWh by 2020	
Federal - Clean Energy Target (***CET***)	Unknown	Would provide for low emission generation to be used and developed post 2020 Proposed only
QLD - QRET	50% by 2030	Floating target of between 4,000 MW to 5,500MW by 2030
NSW	-	LRET only
VIC -VRET	Target of: 25% by 2020 40% by 2025	Auction scheme estimated: Additional 3,400MW by 2025 Additional 5,150MW by 2030
South Australia	50% by 2025	Aspirational only, but achieved through the RET/LRET Will be (closely) achieved through the LRET
Tasmania	-	LRET only

Table 2: Proposed Federal and State-based renewable energy schemes

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

Table 3: Renewable projects intending to be developed

Despite the uncertainty around a Commonwealth-based RET, and the adoption extent of the Finkel recommendations or NEG policy,[4] there are a range of programs and schemes that have been introduced by Commonwealth and State Governments. These have incentivised the uptake of low emission technologies 'behind-the-meter', on the distribution network and in the wholesale market.

3.3 Demand growth

The last 10 years of demand projections from AEMO are well understood, which is that demand growth flattened and decreased over the period 2008 to 2017 and has now appeared to have levelled off, while AEMO continued to overstate projections until possibly 2016. The reasons for this were energy efficiency, increased electricity prices and rooftop PV. This graph from the AEMO 2018 ESOO is shown in Figure 2.

The AEMO demand projects contained in the 2018 ESOO (shown in Figure 1 below) show an increase in NEM-wide demand outlook compared to the flatter outlook contained in the 2017 ESOO. While AEMO do not publish details of their

[4] (Finkel et al. 2017).

projections, reasons for the increase over 2017 include the Portland smelter remaining in service and higher economic activity.

MJA commenced modelling using the flatter 2017 demand projections and consider these to be a better central outlook than the 2018 demand projections. The 2017 AEMO demand outlook was the basis of the base case demand projection used. The use of a flatter demand outlook is considered reasonable and prudent when the wide variation between the low demand outlook and high demand outlook is considered.

There is potential for demand to be higher than projected. Components of demand that would result in increased demand are EVs, lower electricity prices, increasing population, and increasing industrial demand.

Lower demands primarily result from industrial demand reduction (including smelters) and higher take-up of behind-the-meter rooftop PV and battery storage.

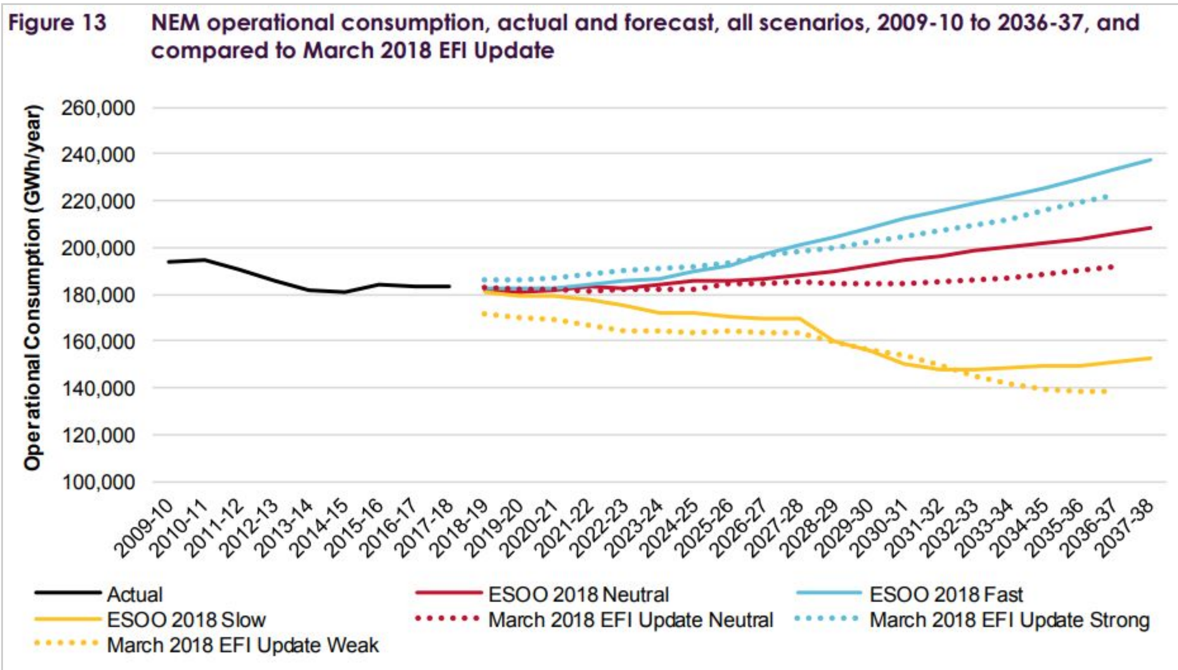


Figure 1: AEMO NEM-Wide Demand Projection contained in the 2018 ESOO [Source: Figure 13 AEMO 2018 ESOO]

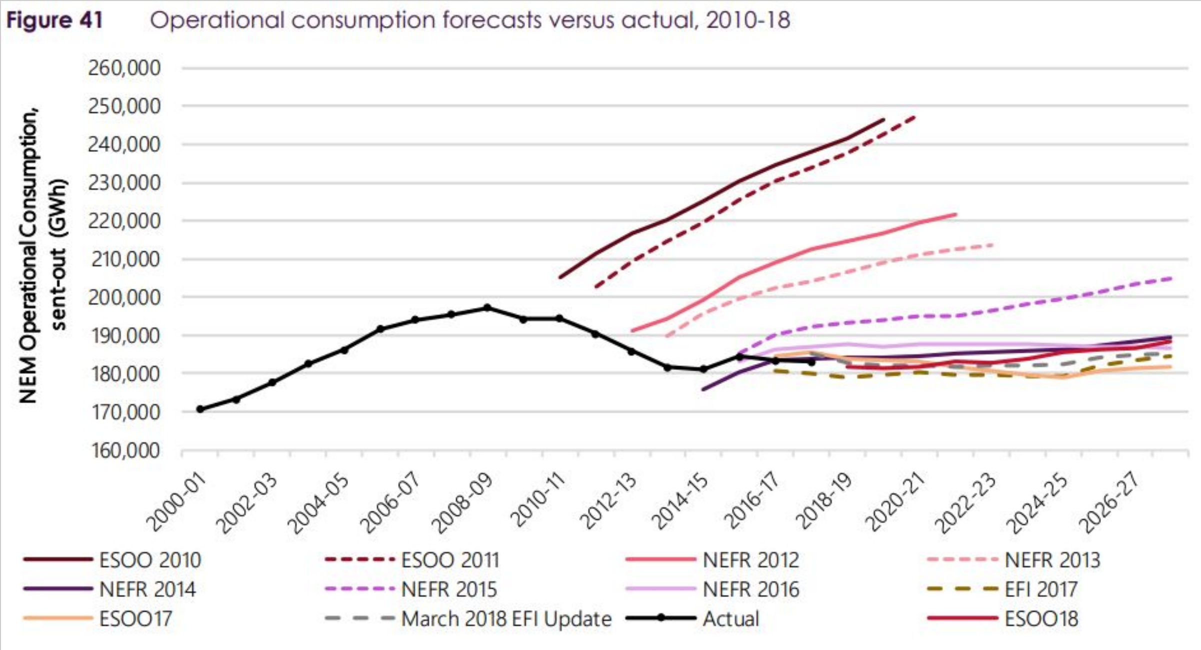


Figure 2: Historical NEM Projections to Actual [Source: Figure 41 AEMO 2018 ESOO]

3.4 Coal generator closure profile

The closure profile of the existing coal generators in the NEM is a critical assumption. A longer continuation of the coal power stations would delay the development of new VRE and gas generation. This would decrease the value of storage.

Apart from Liddell, there are no publicly announced coal generator retirements. Assessments by AEMO and transmission planning bodies on the closure profile are based on power station age and assessments of remaining economic life.

The basis of the coal closure profile is the profile presented in the AEMO ISP, notably, coal plant closing after 50 years of service except for Loy Yang A and Loy Yang B which close after 60 years of service. The closure dates are shown in Table 4, Figure 3 shown the reduction in coal power station capacity resulting from this closure profile.

State	Power Station	Closure Date
QLD	Tarong	2036
	Tarong North	2053
	Stanwell	2046
	Callide Power Plant	2051
	Callide B	2038
	Millmerran	2052
	Kogan Creek	2057
	Gladstone	2029

New South Wales	Eraring	2032 (calendar)[5]
	Vales Point	2028
	Mount Piper	2043
	Bayswater	2035
VIC	Loy Yang A	2048
	Loy Yang B	2056
	Yallourn	2032

Table 4: Coal Power Stations Closure Dates (Base Scenario)

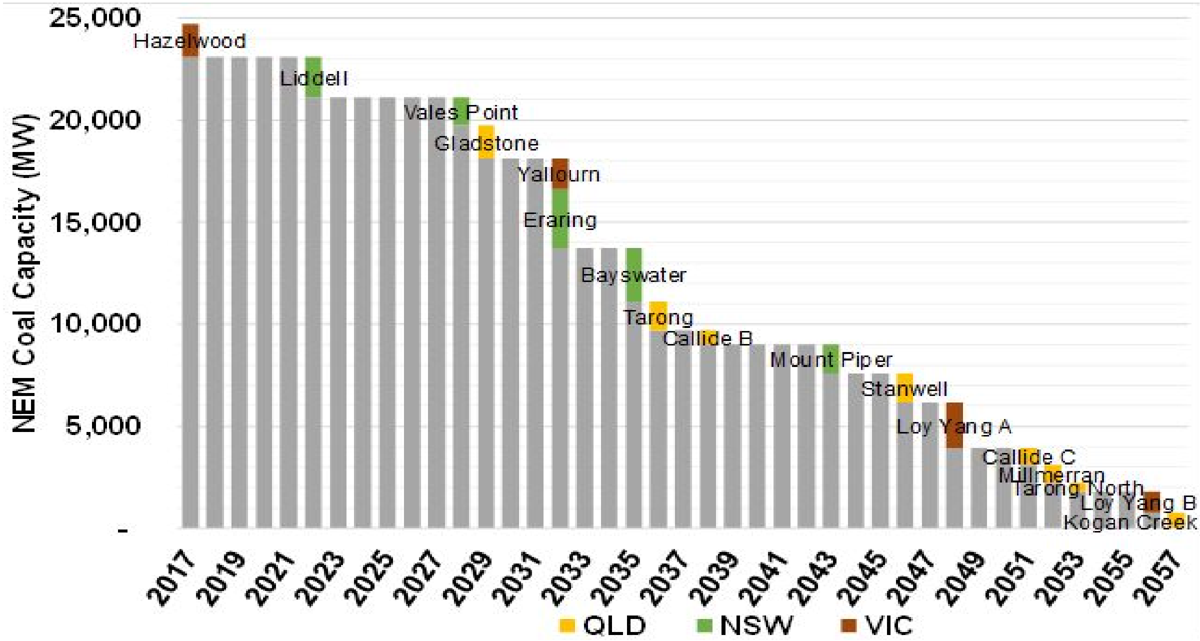


Figure 3: NEM-Wide Coal Generator Closure Profile [Source: MJA]

Noteworthy are the following:

1. By 2035 55% of coal plant would have closed;
2. By 2045 75% of coal plant would have closed; and
3. All existing coal plant would have closed by 2060.

MJA slightly modified this closure profile for the purposes of minimising the size of annual disruptions that would likely be agreed to prior to closure. This had coal generator closures organised in order the minimise annual step changes (to minimise disruption and maintain reliable supply).

[5] Eraring have indicated that Eraring will be closed by 31 December 2032.

3.5 Existing coal generator performance

3.5.1 General

Coal power stations remain the dominant generation type in all States other than SA and TAS, and the operation of these plants can have a significant influence on the profile of regional spot prices and the economics of new generation.

The key performance issues for operating coal plant are:

1. **Availability** - also referred to as generator reliability;
2. **Minimum Generation (*mingen*)** – this is the minimum level of output before high cost auxiliary fuel is required (making reduction in output below this level expensive); and
3. **Ramp rate** – the maximum rate at which a generator unit can increase or decrease output.

These performance issues are relevant to the economics of VRE and consequently storage.

3.5.2 Coal generator ramp rates and Forced Outage Rates (FOR)

An increase in ramp rates would reduce the amount of surplus low-cost coal generation for pumping and increase the amount of fast response capacity provided by coal plant, thereby reducing the supply need from other sources. MJA ramp rate assumptions are consistent with recent historical analysis of station ramp rates for each individual coal plant.

Generator forced outage rates are important as reduced generator reliability would act to increase spot price volatility due to generator breakdown, thereby increasing the economics of gas plant, VRE and storage.

From previous work undertaken by MJA, modelling has shown that in relation to the impact on power system reliability, an increase in the FOR is approximately equivalent to the removal of generator capacity equal to the average capacity reduction associated with the increased FOR.

The average increase in FOR utilised (excluding Liddell) was 1.7%, which is equivalent to an amount of coal capacity of about 300 MW.

3.5.3 Coal plant mingen levels

Reduced mingen levels would reduce the amount of 'surplus' coal generation that can be purchased for pumping at low spot prices. Of the three coal plant performance issues noted, reducing mingen levels is likely to provide the greatest impact to the economics of pump storage through the influence this would have on the availability of low priced pumping energy.

Review of mingen levels and actual coal plant operation demonstrated that for most coal plant there was an alignment of design values and observed outcomes, and that these were the same as AEMO published data. There were four exceptions:

1. Mt Piper, Bayswater, and Loy Yang A had their minimum levels 50 MW lower than AEMO; and
2. Millmerran with AEMO minimum 170 MW, and market data 320 MW.

The modelling used the actual observed minima.

Through work by Aurecon, various options were identified that could reduce mingen levels. These were considered through sensitivity analysis.

3.6 Transmission development

The AEMO ISP published in June 2018 presented a long-term transmission development plan based on the NEM moving to VRE generation and storage as the coal plant closes. This outlook was founded on the stated need to decarbonise and the basis that VRE plus firming will be lower-cost than coal and gas generation, even in the absence of carbon abatement limits (and associated pricing).

The major upgrades proposed in the ISP are as follows:

1. Increased interconnection capacity between NSW and QLD (upgrades of 190 MW and 460 MW for a total of 650 MW in both directions by 2020);
2. Increased interconnection capacity between NSW and VIC (170 MW in both directions);
3. Riverlink - an 800 MW interconnector between SA and NSW;
4. Bannabylink - provides Snowy 2.0 connection to NSW (reference node) and a 2,000 MW increase (in both directions) between Snowy Hydro and Sydney;[6] and
5. Keranglink - 2,000 MW increase (in both directions) between Snowy Hydro and Melbourne.[7]

The ISP had the Bannaby and Kerang links developed by 2035 without Snowy 2.0 to support the increased transmission and Renewable Energy Zones (***REZ***) required (associated with increasing VRE), with Bannaby link developed to coincide with Snowy 2.0 and Kerang link moved forward to 2030 should Snowy 2.0 be developed.

Following discussions between Snowy Hydro and MJA, it was concluded that the transmission timing in the Base Scenario would be as presented in Table 5. The 2026 development of the Bannaby and Kerang links in the Base Scenario reflected a belief that these will be required with the closure of NSW and VIC power stations, to support VRE development and provide firm capacity to SA via Riverlink.

Update	Without S2.0	With S2.0

[6] ISP refers to Bannabylink as Snowy link North.
[7] The ISP refers to Keranglink as Snowy link South.

	Base	AEMO ISP	Base	AEMO ISP
Riverlink	2024	2023	2024	2025
NSW-QLD upgrades	2025	2025	2025	2025
Vic-NSW upgrade	2021	2021	2021	2021
Bannabylink	2026	2035	2026	2026
Keranglink	2026	2035	2026	2030

Table 5: Transmission development scenarios

An issue with Riverlink is that without additional transmission works such as Bannabylink, Riverlink does not provide firm capacity between SA and NSW. This means Riverlink would not enable additional capacity from NSW when SA or VIC may require this.

The reason for this is that Riverlink does not involve any transmission works north of Wagga Wagga. This is observed from Figure 4 below, which has the transmission lines represented in a structure that includes the abolished Snowy region.

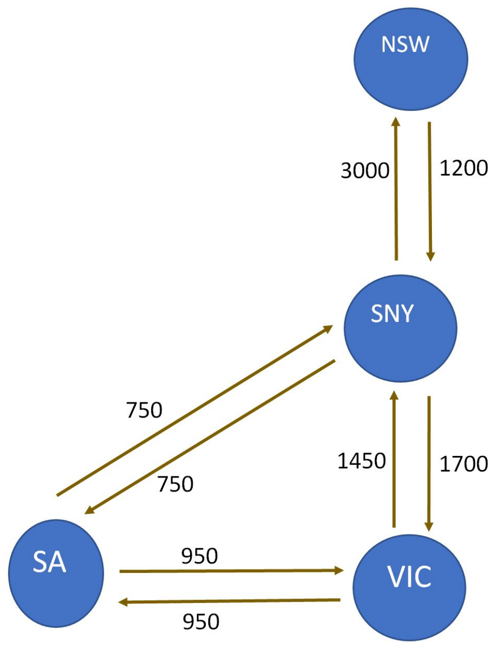


Figure 4: NEM-wide coal generator closure profile

3.6 Supply-side options and costs

The supply-side options considered in the modelling were as follows:

1. High efficiency, low emissions (***HELE***) coal plant;
2. Gas plant – Combined-Cycle Gas Turbine (***CCGT***);
3. Gas plant - Open-Cycle Gas Turbine (***OCGT***);
4. Gas plant – reciprocating;
5. Battery storage;

6. Pumped Hydro Schemes;
7. Solar generation; and
8. Wind generation.

Figure 5 presents the costs of these generator types and battery storage:

1. Costs of conventional thermal plant (coal, CCGT, OCGT) are not expected to decrease significantly, noting that coal HELE plant are expected to decrease in cost. The cost for these plants, expressed as $/MWh, increases as the capacity factor reduces (as the same capital supports a lower level of generation.) The cost of these plants in 2019 is a function of capacity factor;
2. Solar and wind generation costs are projected to continue to decrease. As these types of generators have a fixed capacity factor they are expressed as $/MWh; and
3. Battery costs, expressed as $/kW, vary with the amount of storage hours. This means that storage hours need to be specified; the costs shown are based on 4 hours storage.

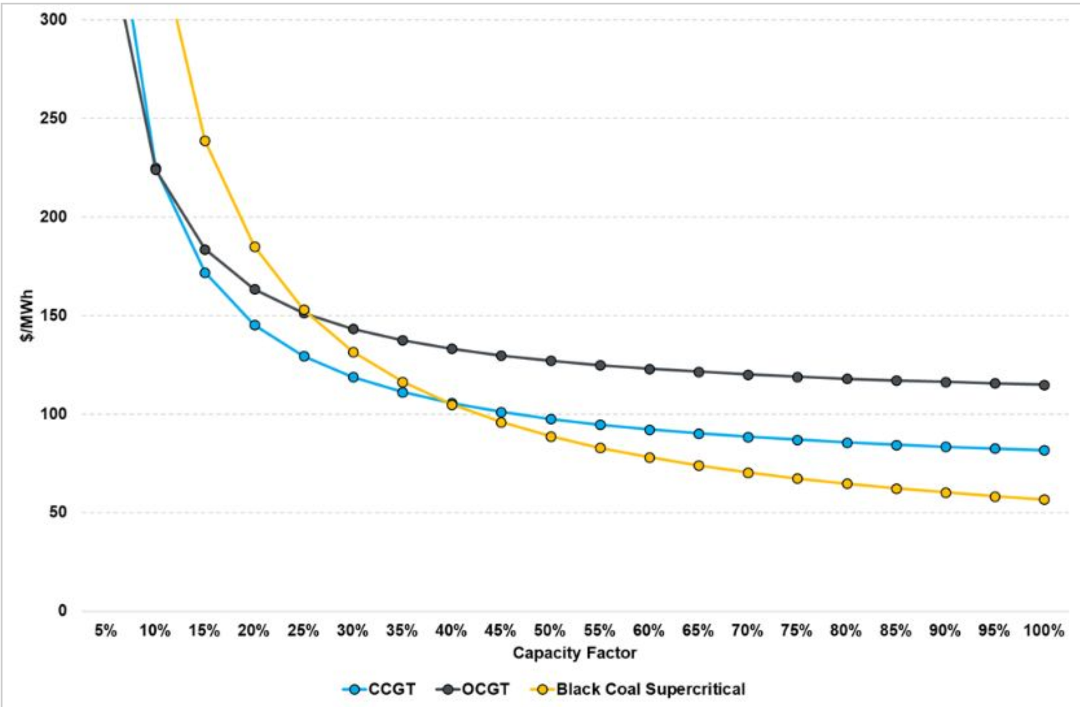


Figure 5: Thermal Generation Levelised Cost of Electricity (LCOE)[8]

[8] As dispatchable generation output is controllable, cost is expressed based on the capacity factor of operation.

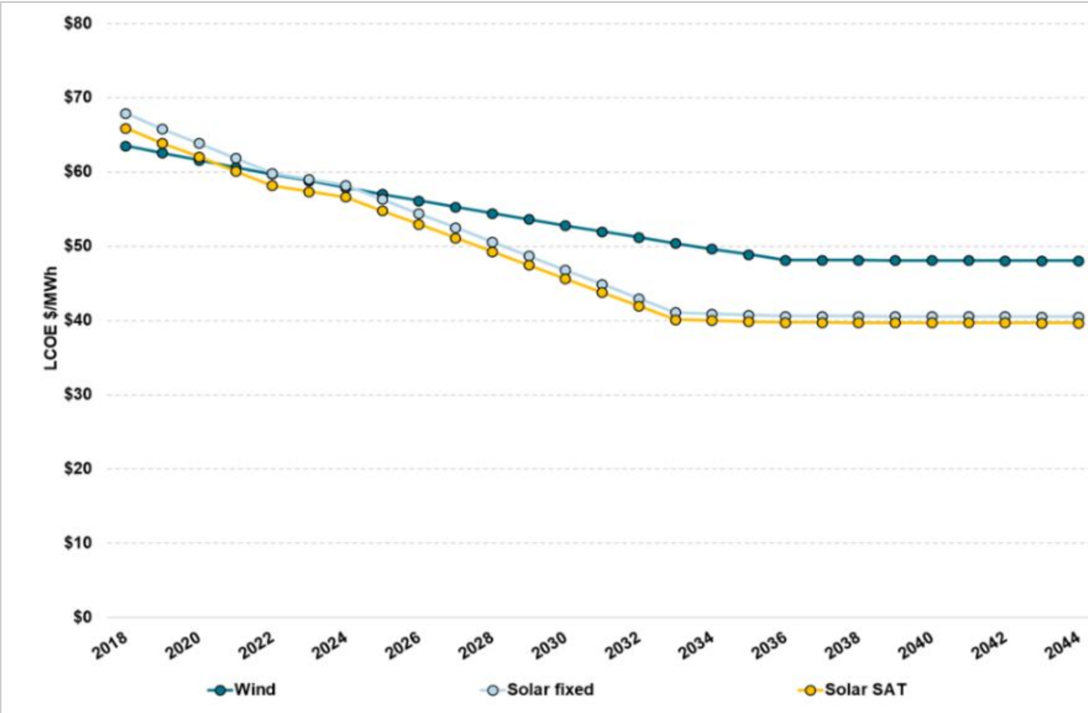


Figure 6: Solar and Wind Generation LCOE[9]

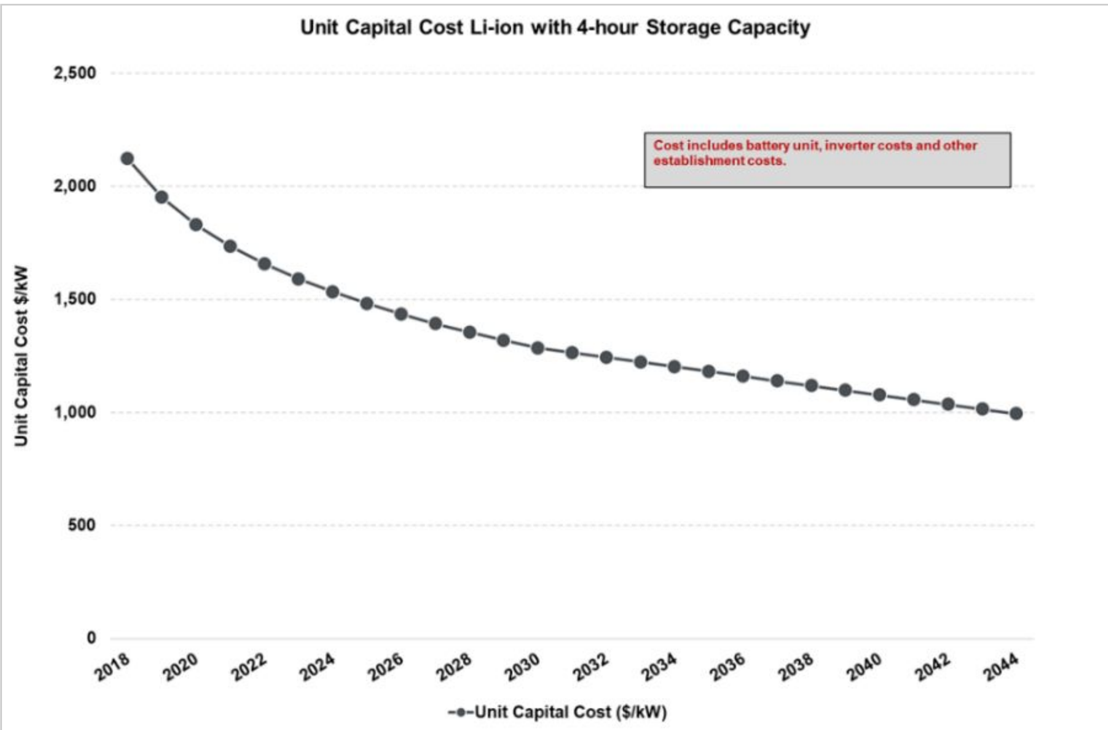


Figure 7: Battery Costs $/kW/year.[10]

[9] Solar and wind generation operate based on sunlight and wind. Cost is based on generation at the expected available outlook level..

[10] Battery costs are more appropriately expressed as $/kW/year based on a specified level of storage (usually expressed as hours of operation when storage is full).

3.7 Gas and coal costs

Gas and coal costs are fundamental to NEM spot price outcomes and the arbitrage price spread (while these plants are operating) and the viability of new generation. The AEMO 2018 GSOO indicated that while the gas outlook may have improved in the medium term, the gas reserve outlook is that substantial new reserves are required and that these will likely be at higher cost.

AEMO publication extract:

> 'A change in international market dynamics, lower demand for gas-powered generation, new pipeline interconnections and the Federal Government's Australian Domestic Gas Supply Mechanism (***ADGSM***) have delivered an improved outlook for Australia's east coast gas markets.'[11]
>
> 'The reserve mix required to meet domestic demand is shown in Figure 8 below, with rapid decline in production from 2P developed and undeveloped reserves clearly visible, mostly from fields located within the southern states.'
>
> 'As existing fields decline, exploration and development will be needed to deliver these contingent and prospective resources to market. These new gas supplies will help improve adequacy of supply but, as flagged in the 2017 GSOO, supply from these fields is likely to be more costly than existing production.'[12]

The reserve outlook published in the 2018 GSOO is presented below. As observed, by 2025 there is a substantial shortfall in the known commercial gas required to satisfy demand.[13]

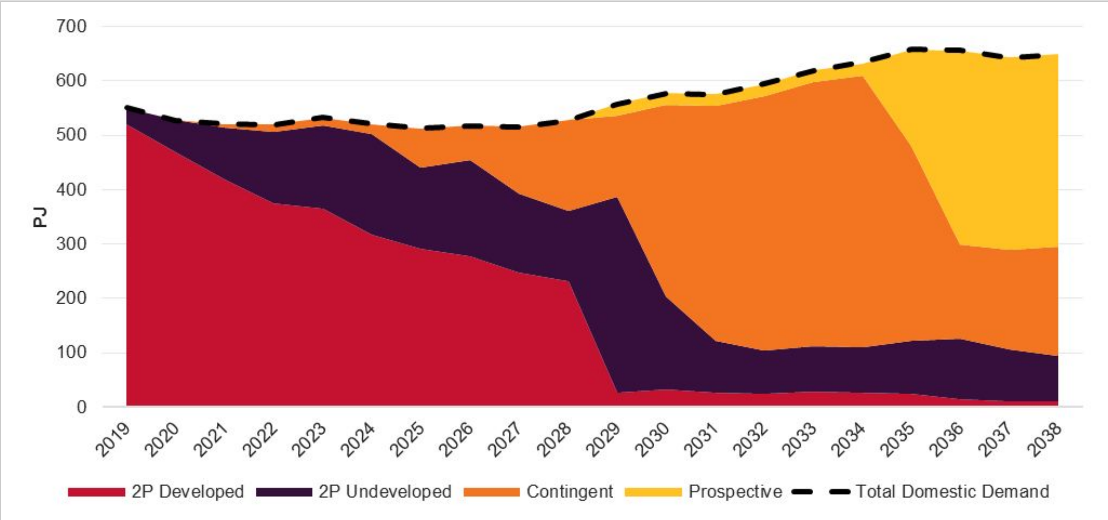


Figure 8: For eastern and south-eastern Australia - Status of reserves and resources to meet domestic demand, 2019-38[14]

[11] http://energylive.aemo.com.au/News/Sector-changes-deliver-improved-gas-supply-outlook.
[12] AEMO 2018 GSOO Executive Summary.
[13] Proven and Probably (2P) commercially recoverable from known accumulations. 50% probability that the quantities will equal or exceed the estimate. Contingent gas is potentially recoverable from known accumulations but not ready for commercial development. Prospective resources are potentially recoverable from undiscovered accumulations such as shale gas.
[14] (AEMO 2018).

To assist in the outlook of gas prices, Snowy Hydro commissioned a study from EnergyQuest to provide an outlook of the east coast gas market. This outlook concluded that the gas supply outlook was very tight, in particular:

1. Supply from Gippsland which produced 360 GJ in 2017 (about 50% of the east coast domestic gas demand) would have a production output of half this by 2026 and exhausted by 2036;
2. Lifting the gas moratorium in VIC would have little impact for at least 10 years and possibly for much longer;
3. NSW is unlikely to have any significant gas production;
4. All low-cost QLD Coal Seam Gas (***CSG***) has been allocated for export. The QLD CSG available for the domestic market is lower-productivity and higher-cost gas;
5. Gas from Northern Territory remains prospective and high prices may be required for this to be commercial (ie derived from 2P (probable rather than proven) reserves); and
6. Imported gas will possibly be needed.

The consequence of this is a significant level of uncertainty regarding where the future gas will come from and the cost of this gas. The resulting indicative gas prices were higher than that used by AEMO in the ISP modelling, and had a floor of about $8/GJ delivered to Melbourne.

Using the above information and MJA's own modelling, the gas price assumptions (for delivered gas) are shown in Figure 9 below.

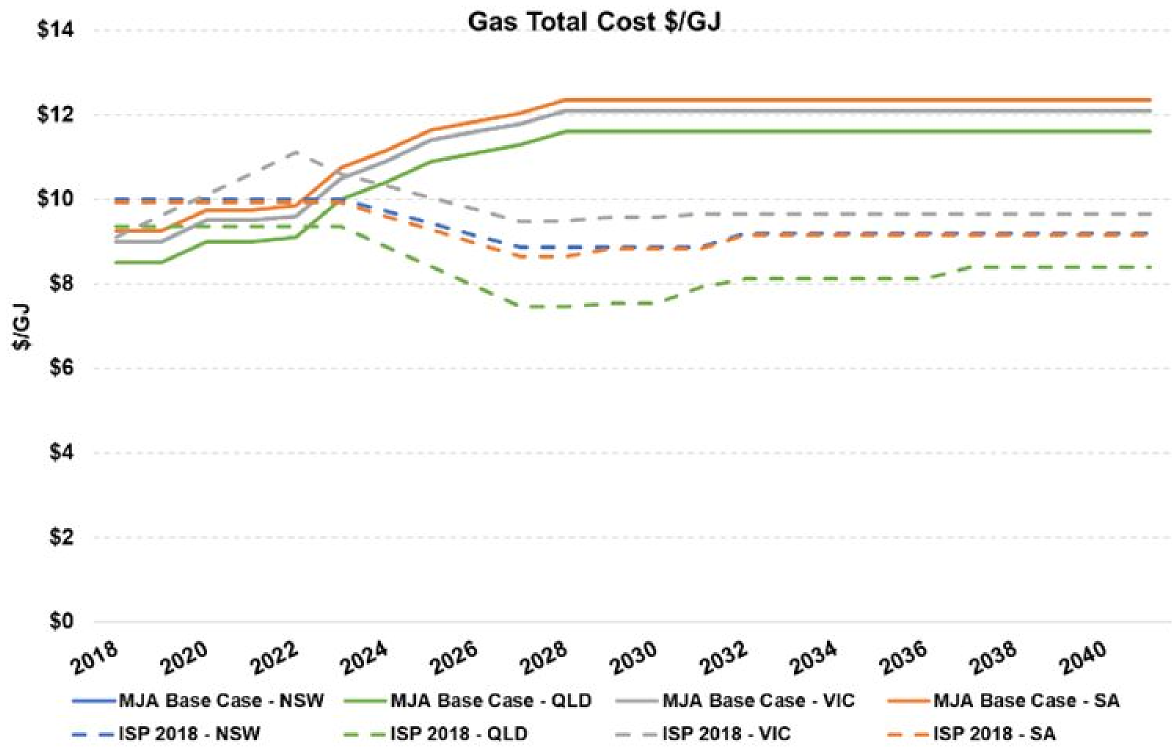


Figure 9: Delivered Gas Prices $/GJ

3.8 Behind-the-meter response and costs

3.8.1 Rooftop PV

The projections of rooftop PV were those developed by AEMO for the ISP. Changes to this projection were made on a scenario basis.

3.8.2 Behind-the-meter batteries

The projections of distributed batteries were developed based on economics and usage profile. This was consistent with that of the AEMO ISP. The charging and discharge profile were developed by MJA, and this was also close to that used by AEMO in the ISP modelling.

EVs may participate in grid storage, but the initial findings from high penetration markets suggests they are unlikely to. Our initial research suggests that EV batteries are more likely to draw from the grid than contribute to the grid (Vehicle-to-Grid).

3.8.3 Demand Management

Demand-side management was included in the modelling. The assumptions were those used by AEMO in the ISP modelling.

3.9 Electric Vehicles

MJA expects that take-up is likely to be slow out to the mid-2020s given the relatively higher cost of EVs compared to Internal Combustion Engine (***ICE***) vehicles, as well as factors including insufficient charging infrastructure, a low number of different models, and concerns about range and servicing. From the mid-2020s there is expected to be strong acceleration in take-up as EVs become cost-competitive, the technology is proven and infrastructure is in place.

A saturation point is expected by 2055-60 (which would equate to about 55-60 TWh of new demand), given EVs are expected to be considerably cheaper to buy and operate and zero (or very low) carbon emissions policies are likely to be in place. There will likely be only a small number of 'vintage' ICE vehicles remaining in operation.

AEMO's current ('neutral' scenario) expectations for EV penetration are for 2% of the fleet (440,000 vehicles) by 2025, 7% (1.6 million vehicles) by 2030 and 21% (5 million vehicles) by 2038. Recent forecasts by Bloomberg New Energy Finance (***BNEF***) are similar to AEMO. MJA forecasts out to 2075 are shown in Figure 10.

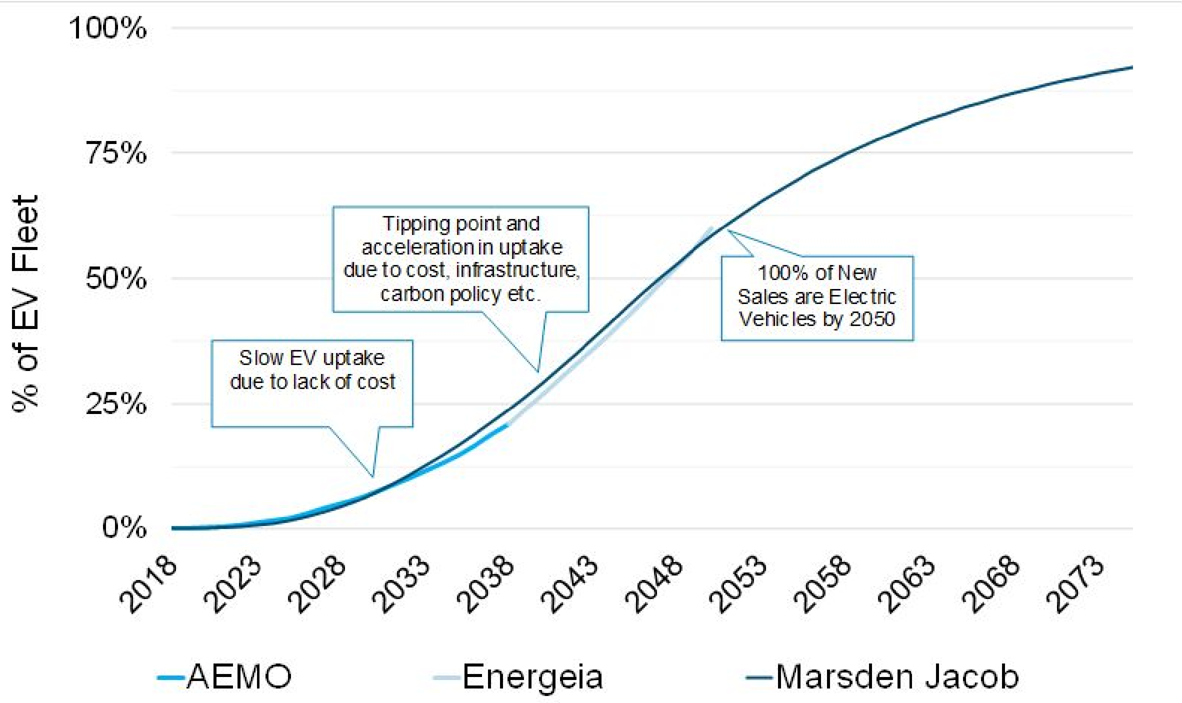


Figure 10: Electric Vehicle Projection

3.10 Emissions and renewable energy policy

Environmental policy on limits on emissions and renewable generation is a fundamental assumption of NEM modelling. The modelling scenarios undertaken and presented in this report contained those with and without emissions reduction limits. The base assumptions had no emissions limits.

A description of the NEG rules is presented in the *NEG and emissions policy* section below.

3.11 Renewable energy schemes

3.11.1 General

As at FID there are three renewable energy schemes in operation. These schemes and their status are described below.

3.11.2 The Large-scale Renewable Energy Target (LRET)

LRET Overview:

1. A federal government legislated scheme that commenced operation in 2020 and is due to terminate on 31 December 2029;
2. Covers the NEM, the WA and NT electricity markets;
3. Renewable generators create LGCs and require wholesale energy purchasers (mostly retailers) to purchase that year's target level of LGCs that year. Individual obligations are determined by prorating in proportion

to energy purchase levels. There is a penalty for each LGC that should have been purchased; and

4. The maximum penalty price (called the Shortfall Penalty) is set at $65 per LGC, non-tax-deductible and constant in nominal terms over the life of scheme.

The committed generation eligible for LGCs is projected by MJA to result in a significant stockpile of surplus LGCs. This is the reason for a projected collapse in forward LGC prices. Post-2021, new VRE generation not developed under the VRET or QRET (discussed below) will not obtain much value from LGC sales.

3.11.3 The Victorian Renewable Energy Target

VRET Overview:

1. The VRET is a Victorian Government-legislated renewable generation scheme that has a target of having VIC 25%-supplied by renewable generation by 2020 and 40%-supplied by renewable generation by 2025;
2. The VRET is complementary to the Federal RET before 2020 and additional after 2020;
3. The VRET operates by offering long-term contracts to successful renewable energy projects (reverse auctions are held periodically); and
4. There are no tradable certificates.

The targets of this scheme are achievable and have been assumed to be met in the Base Scenario

3.11.4 QLD Renewable Energy Target

QRET Overview:

1. The QRET is a QLD Government non -legislated renewable generation scheme that has a target of having QLD 50% supplied by renewable generation by 2030;
2. VRET operates by offering long-term contracts to successful renewable energy projects (reverse auctions are held periodically); and
3. There are no tradable certificates.

The targets of the QRET will be challenging to meet for the following reasons:

1. The amount of coal plant in QLD, and that Gladstone is the only power to retire pre-2030 (in 2029); and
2. QLD is not suitable for large amounts of wind generation and large amounts of solar are more difficult to integrate.

The targets of this scheme are achievable (although difficult) and have been assumed to be met in the Base Scenario.

3.12 Marginal Loss Factors

The changing flow patterns in the NEM are resulting in large changes in MLF. For new renewable generators, particularly in northern QLD, this has MLFs substantially decreasing. A year-on-year fall of an MLF at a connection point is likely to have a positive impact on customers and a negative impact on generators at that connection point.[15] This is a significant issue for the developers of new solar and wind facilities.

AEMO has held sessions canvassing potential solutions to this and potential options for changes to the approach to MLFs. This includes the introduction of Dynamic Marginal Loss Factors (***DMLF***). However, consistent with AEMO assumptions, MJA concludes that on a NEM-wide basis the current MLFs are the best estimate of these into the future.

3.13 Ancillary and other services

3.13.1 General

This section presents the ancillary service revenue streams that generators can earn on the NEM, and a possible new service associated with energy security. The likely path of ancillary service prices and revenues are presented.

3.13.2 Frequency Control Ancillary Services

Frequency Control Ancillary Services (***FCAS***) were described in the MJA Feasibility Report and are not described here.

In relation to these services we note the following:

1. FCAS services are 5-minute services with the quantity reflecting uncertainties in demand and generation;
2. Snowy 1.0 participates in FCAS services. The 5-minute raise service is well-suited to Snowy 1.0 as Snowy 1.0 generators do not need to be operating;
3. The Snowy 2.0 variable speed machines can provide FCAS when operating in any mode (generating or pumping). These generators are highly suited to providing FCAS;
4. Batteries are well suited to providing FCAS services (raise or lower) and can do this to the extent they have spare raise-to-lower capacity. The amount of storage a battery has is not relevant as ancillary services operate over 5 minutes;
5. While FCAS prices, particularly the raise services (6 second, 5 minute and regulation), have been averaging between $15 and $26 for 2017-18, these price levels are expected to decrease as increased supply enters the market. Increased supply will come from the demand side and batteries (small and large);

[15] (AEMO 2018).

6. The quantity of FCAS is small, averaging about 500MW per service;
7. The quantity of FCAS supplied is not expected to increase as the uncertainty in VRE will reflect improved output forecasting and increasing diversity; and
8. The result of the above is an expected reduction in FCAS prices but a market maturity not to bring these down to below $5/MWh.

3.13.3 Energy Security Service

As the NEM develops to a higher percentage of generation from VRE, the reliability of supply will increasingly reflect both capacity adequacy and energy adequacy.

Energy adequacy would require the reservation of energy that can be called upon when energy reserves are low. This would increasingly reflect hydro reserves and possibly gas availability.

The value of security provided by an energy reserve may translate into a service contracted by AEMO. Snowy 2.0 would be an ideal supplier of such a service.

4 NEM transformation

The NEM is undergoing a transformation associated with the reducing costs of large-scale and distributed renewable generation (and now battery), moving forward the closing of aging coal power stations and potential climate policy. The economics and narrative of this transformation are common to all future scenarios.

This section describes the dynamics and economics of this transformation and the factors that will determine NEM development under different development scenarios.

The description is complex but important to the understanding of the economics of NEM development under the different scenarios presented.

This section presents the underlying evolution that is occurring in the NEM and that is common to all scenarios, and which underpins the economic trade-off between different supply options. This is a natural precursor to the design of the modelling and scenarios.

While not quantitative, it does utilise the outlook of reference assumptions presented previously in this chapter.

In the context of Snowy 2.0 development it is convenient to divide the development of the NEM into three periods:

1. **2018 – 2025** - This is the period prior to the commencement of Snowy 2.0 and is a period that has a substantial increase in VRE. This period sets the market conditions that will exist when Snowy 2.0 would enter;

2. **2025 – 2047** - This period is the first 23-years of Snowy 2.0 operation. During this period most of the existing coal plant will close and the nature of the NEM will change substantially; and
3. **2048 to 2075** - During this period it is expected that the NEM will move to very high levels of VRE.

The changing dynamic in each of these periods is presented in the sections that follow. The last section then presents the manner in which spot prices would be expected to behave accounting for the described changed NEM.

4.1 NEM: 2018 to 2025

4.1.1 NEM in 2018 - Mostly thermal

The largest NEM States of QLD, NSW and VIC are predominantly supplied by thermal generation (coal and gas). TAS is near-all hydro, with some wind generation, and SA is close to 60% supplied by wind and solar generation with support from SA gas generators and connection to VIC.

On a total NEM-wide basis the energy supplied by generation in 2017/18 was:

1. 72% coal generation;
2. 10% gas generation,
3. 7% dispatchable renewable generation (hydro);
4. 7% VRE (large-scale wind and solar generation); and
5. 4% rooftop PV.

The characteristic of generation supply under a system dominated by dispatchable thermal generation (which applies to VIC, NSW and QLD) is illustrated in Figure 11. This figure shows a load duration curve[16] over a year and the generator types that supply this demand 'stacked' from lowest operating cost to highest operating cost. From this figure we note the following:

1. All periods (except for a few hours each year during times of very high demand) have substantial spare generation. This means that the system is 'energy long', as the unused generators can be used at any time to supply additional energy;
2. System reliability is determined by the availability of generator capacity at times of very high demand;
3. A limited amount of VRE generation can be absorbed within the flexibility of the thermal fleet (and possibly some moderate amount of storage);
4. Spot prices reflect the supply and demand of thermal generators each dispatch period (can be volatile); and
5. Wholesale energy purchases do not require firming products.

[16] A load duration curve is the half-hourly demands ordered from highest to lowest.

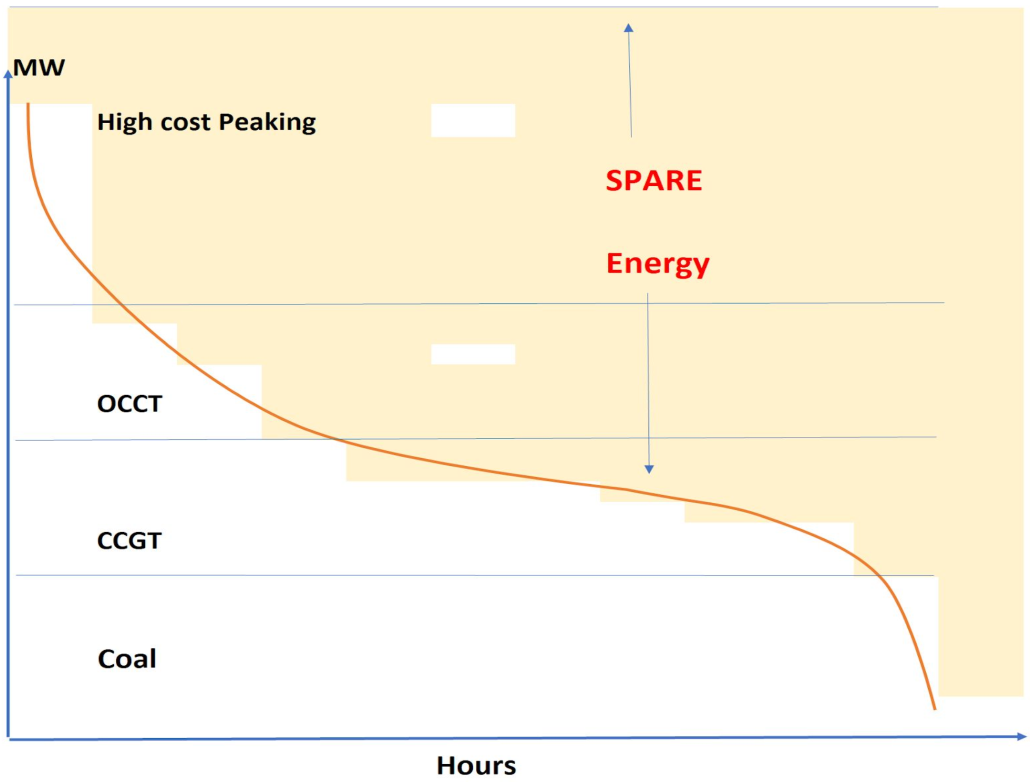


Figure 11: All-Thermal System[17]

TAS is 95% hydro and 5% wind, with support from Basslink to manage energy surpluses and deficits.

Unlike systems high in thermal generation where supply reliability is determined by capacity outages, prior to Basslink TAS had surplus capacity but had the risk of being short energy during drought years (and being long energy in wet years). This necessitated thermal generation for energy reserve (Bell Bay Power Station). An important factor in the economics of Basslink was the energy support it provided to TAS. The recent failure of Basslink highlighted the risk of energy shortages in a predominantly renewable power system.

SA is a high VRE region supported by interconnection with VIC, gas generation and a battery. SA is near the limit of the amount of VRE it can support. Additional gas plant is not economic before Torrens Island A closes and additional interconnection is required for any new VRE development in SA to be undertaken. The benefits the proposed SA-NSW interconnector provide to SA are both improved supply reliability and the option to further develop VRE in SA.

4.1.2 NEM developments changes to 2025

Major developments and issues influencing the NEM development over the period to 2025 include the following:

1. An outlook of very little if any demand growth;

[17] All-thermal system is energy-long and possibly capacity-tight. Reliability is determined by capacity adequacy.

2. A substantial amount of new VRE generation committed to enter in VIC, NSW and QLD, financially supported by the LRET, VRET, and QRET;
3. SA is near the limit of the amount of VRE that can operate within SA. For additional VRE to be developed in SA new interconnection is required (to and from SA);
4. The closure of Liddell, which has been assessed by AEMO as resulting in NSW being 1,000 MW short of capacity. The capacity deficit is proposed to be supplied by a CCGT plant (indications are about 400 MW), increased interconnection to VIC (150 MW) and QLD (300 MW), a possible battery and additional VRE;
5. In 2025 the introduction of Snowy 2.0 would provide 2,000 MW of additional capacity;
6. A substantial level of transmission development is projected (detailed in the AEMO ISP) economically based on the transformation from predominantly coal generation to VRE generation:
    a. Among other things, Riverlink will provide for more VRE generation development in SA;
    b. Kerang link and Bannaby link will provide for REZs in VIC and NSW; and
    c. QLD-NSW interconnection upgrades will provide low-cost generation from QLD to reach NSW;
7. An outlook (as reflected in the forward curve) of reducing spot prices (from current levels averaging about $90/MWh) as the large amount of committed VRE enters;
8. An outlook of a very tight gas market with gas prices projected to reflect international Liquified Natural Gas (***LNG***) gas prices;
9. The potential for deteriorating reliability of the aging coal generators due to an observed increase in coal generator breakdowns;
10. A government focus on limiting portfolio use of generator market power through potential penalties (such a requiring a certain level of portfolio disaggregation); and
11. Uncertain federal environmental policy ranging from no new policy (Coalition) to a 45% reduction in emissions by 2030 (Labor). One element of agreement may be enacting the reliability obligation of the NEG.

4.1.3 NEM in 2025

The NEM will be different in 2025 compared to the present and assuming Snowy 2.0 is developed:

1. The NEM will have significantly more VRE installed than in 2018. VIC will be supplied by 40% renewable, SA 86%, NSW 20% and QLD 38% supplied;
2. The amount of coal and gas plant provides for VRE to be absorbed into the system without the need for material firming assets;
3. Transmission upgrades between SA-VIC-NSW will have been completed. This will have the effect of reducing both spot price differences between SA-VIC-NSW (due to both losses and flow constraints) and will have these

three regions largely behave like a single 'super' region. NSW-VIC arbitrage opportunities would be reduced;
4. The QRET in QLD, plus no coal closures in QLD, will have QLD a net exporter during solar generation periods to NSW;
5. Coal generator operation will be forced more often to mingen levels, which will offer low-cost pumping opportunities; and
6. Solar and wind generation have an increasing discount on average spot price.

There would be insufficient time to develop a new coal power station before 2025, and a new coal power station would not be required regardless, given the coal plant that will still be operating in 2025 and the entry of Snowy 2.0.

4.2 NEM 2025 to 2045 – Coal plant closing

The period 2025 to 2045 is the 20-year period where the NEM regions VIC, NSW and QLD move from being supplied mostly from thermal power stations to being mostly supplied from VRE (with support from gas and storage). This transition is projected to occur rapidly.

In the absence of any policy on emission limits, economics and investor preference will dictate how the closing coal generators will be replaced. This is given by spot price revenues and wholesale purchase risk.

The potential new generators will be VRE (plus increasingly firming), gas and coal generation.

Coal generation development has significant hurdles and these hurdles are likely to increase moving forward. This is due to the bank lending policies on such assets, regulatory risk and the risk of negative consumer reaction.[18] That higher risk places gas plant ahead of coal plant for required thermal generation.

Gas generation has the risk of securing gas supply and at prices that would provide for such investments to be economic. The preference maybe for peaking supply that does not require significant quantities of gas.

VRE has the lowest-cost energy production but requires firming. As VRE increases, firming will be provided by surplus thermal plant and increasingly new gas plant and storage. Storage is essential once surplus low-cost VRE generation is required to be stored for later use. VRE will not replace dispatchable plant capacity, and firming capacity from storage and/or gas plant will be required.

The economics of replacing coal generation by VRE will be complex and difficult. The following are noted:

1. On the current cost curve projections, battery storage (given the amount that will be required in terms of capacity and energy) is not economic. The economics of battery storage will likely be required to be supported by

[18] The risk of coal development was identified in the Finkel Review which placed a high risk weighting on such investment (Finkel et al. 2017).

regulation (ie VRE generation will be required to include a certain amount of storage) and a high premium for risk;
2. Gas generation will be needed to provide the dispatchable capacity resulting from the closure of coal plant and limited battery development;
3. Snowy 2.0 would provide both storage and firm capacity (giving it the ability to operate for many continuous hours); and
4. Energy in storage will have an increasing value as it provides for both improved spot price arbitrage and the sale of premium-based firming products.

The transition of coal plant closure and increasing VRE will have a changing dynamic over the period:

1. Minimum generation level (mingen) presented by the coal fleet will reduce, thereby reducing one component of surplus generation available for pumping; and
2. The dispatchable capacity provided by the coal fleet will reduce, providing opportunities for new capacity to operate (and that will be required to meet high demands). This is likely to be gas plant or storage.

This is illustrated in Figure 12 which illustrates that as coal plant closes, total coal mingen levels decrease and a capacity deficit will emerge.

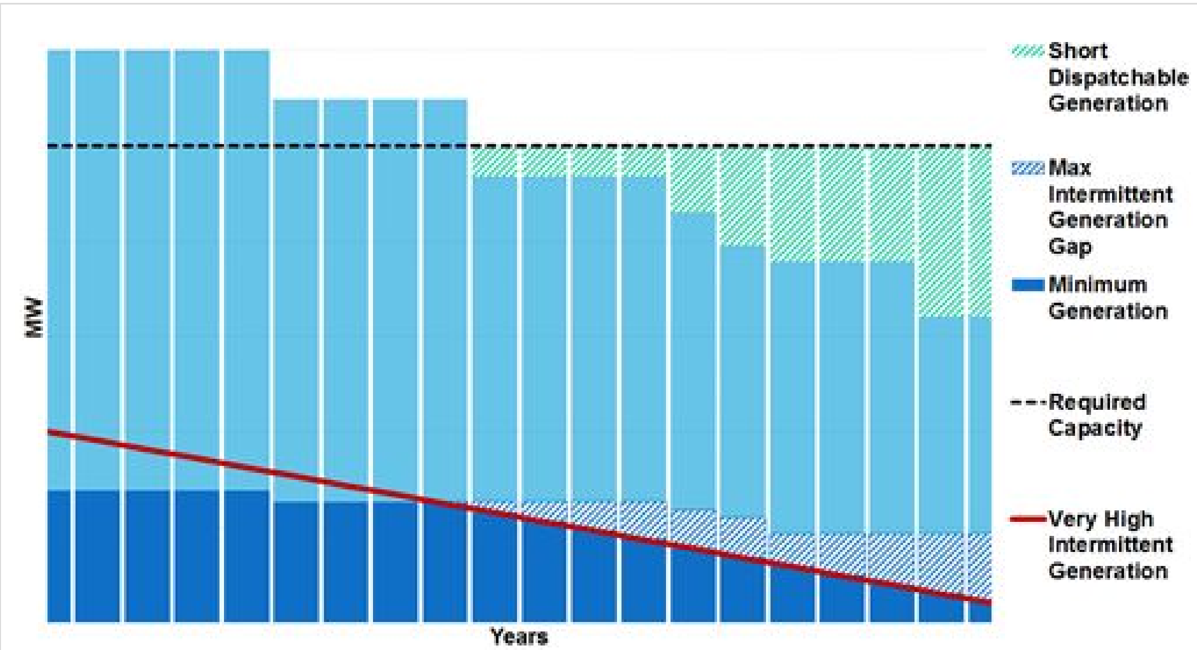


Figure 12: Changing balance in the future (MW)

4.3 NEM 2045 to 2075 – Move to High Renewable Generation

Post-2047 (the last year of the PROPHET modelling (see *Supporting Chapter Five*)) the operation and economics of the NEM will have been totally transformed.

While the outlook is that there will be coal plant operating in VIC and QLD, these plants will be intra-marginal and will have little impact on the dynamics of the NEM. The transformation will be such that the current market arrangements may need radical change.

Given the above, NEM outcomes and economics over this period were considered by addressing the start and end points and how the NEM may develop. Key considerations were as follows:

1. The nature and economics of firming assets;
2. The economic limit of the amount of VRE generation that can operate in the NEM. This will define the NEM once all the coal plant has closed; and
3. The transition to a NEM with no operating coal plant from its position in 2047.

4.3.1 Dynamics of a Near-All-Renewable Power System

Figure 13 below illustrates the load duration curve and generation supply over a year under an all-renewable power system. The following are observed:

1. Renewable generation would be that required to satisfy the total demand GWh. This would require a level of VRE such that demand is met in a year of very low VRE. This is different to a thermal system where generation is developed on the basis of capacity requirement;
2. Storage would be required to capture and store surplus VRE and use this for generation when VRE output is short of demand;
3. The amount of storage capacity (MW) required would at a minimum be the winter evening peak demand - a time when there is no solar output and wind generation may be very low; and
4. The amount of energy storage would need to be sufficient to cover sustained periods of low VRE output and to capture sustained periods of surplus VRE output. Such periods include:
    a. Days of low wind and solar;
    b. 'wind drought' which can be for extended periods (weeks);
    c. Seasonal variations – solar is high in summer and low in winter; and
    d. Drought years where hydro generation is low.

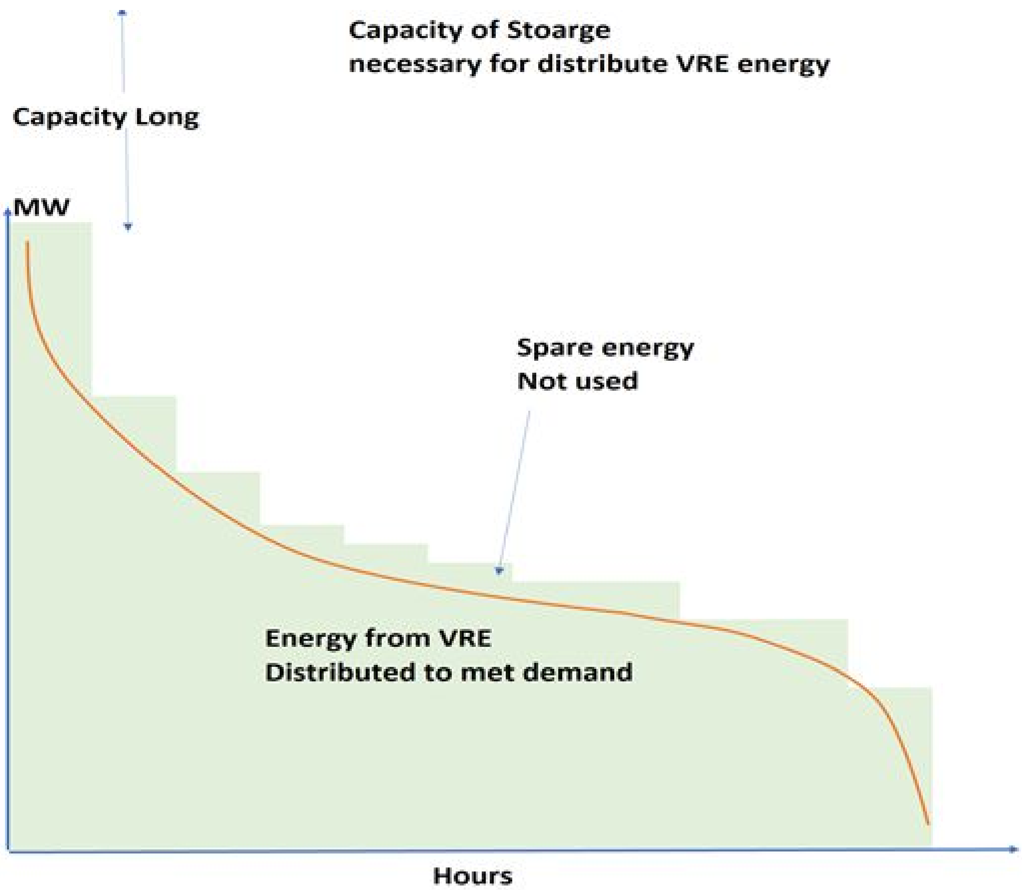


Figure 13: All VRE and Storage System (2075)[19]

4.4 VRE Output Variability

The profile of VRE generation through a year can vary significantly from year to year. There can be very large seasonal and annual variations. This means that at a very high level of VRE, thermal generation support would be required.

The variability of VRE generation output through a year is illustrated in Figure 14, which shows the state of charge, as a percentage of total annual demand (132 TWh for the NSW-VIC-SA region) using three different VRE production traces from the actual NEM outcomes in the years 2015, 2016 and 2017. The seasonal and weekly variation are substantial.

[19] Is energy short and possibly capacity long. Reliability is determined by energy adequacy.

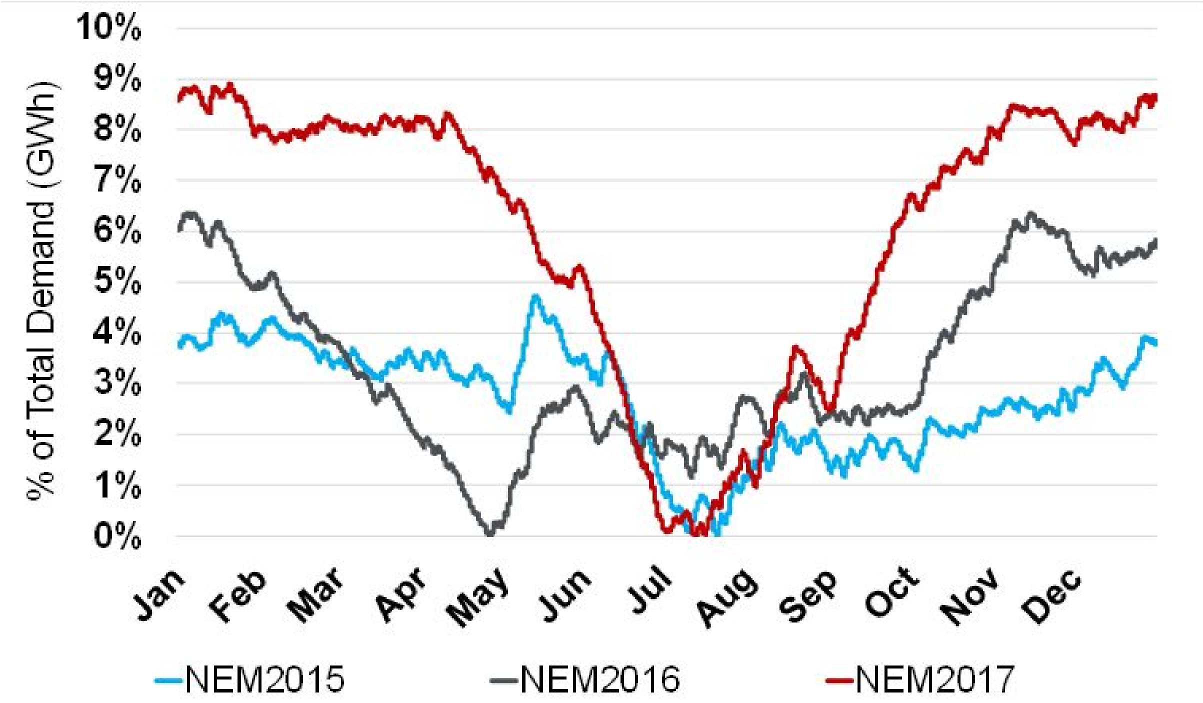


Figure 14: Cumulative Output of a mix of VRE Generators in SA/VIC/NSW

The seasonal profile of VRE output would increasingly become an issue when VRE becomes a substantial component of generation and storage volume is limited. This requires sufficient VRE in winter when solar is low, meaning that VRE is in surplus in summer. This has several consequences:

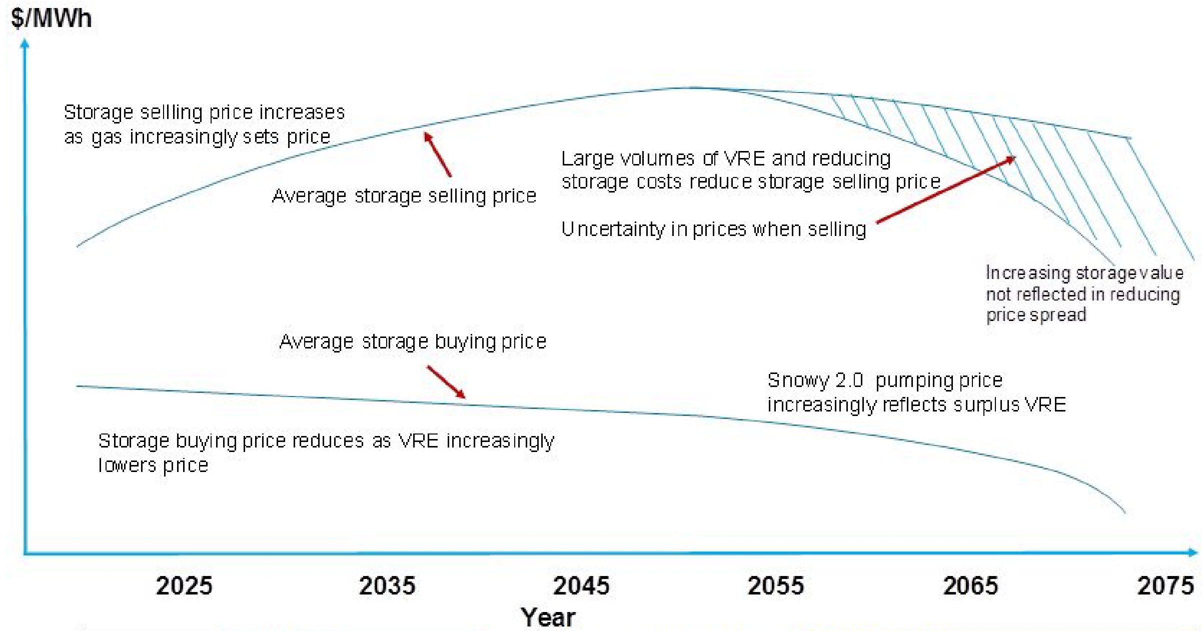
1. Less energy available for pumping in winter;
2. A requirement for higher use of thermal plant in winter; and
3. Higher winter prices and lower summer prices.

The availability of water for Snowy 1.0 does not fit this trend. Snowy 1.0 and Tantangara are operated such that ponds are low entering the winter period in order to address the risk of 1-in-10-year extreme inflows. However, Snowy 2.0 would provide an element of coverage in this scenario by being able to operate at high levels during the winter period when solar is low.

4.5 NEM Spot market and Price Dynamics

Spot prices outcomes will reflect the changing NEM dynamics presented in the previous sections.

The logic of this translation is presented in Figure 15 below. This illustrates the manner upon which spot price dynamics would be expected to change and the consequences for pumped storage and the modelling undertaken. An explanation for the various time periods is shown in Figure 15.



Coal	Starts to close	All NSW coal plant retired	All coal closed
Gas	Gas provides support	Gas remaining lower cost than storage	Gas closing
Storage	Storage needed to support increasing VRE		Value of storage increasing

Figure 15: Trend in Long-term NEM Development

4.5.1 Period 2018

Current (2018) spot prices in the NEM. This has:

1. NSW/VIC/SA spot prices closely linked but with periods where regional spot prices 'separate' through constrained flows at times of high system stress;
2. NSW and VIC dispatch and price outcomes reflect the Short-Run Marginal Cost (***SRMC***) of the generation mix (brown coal, black coal, CCGT, OCGT), capacity value and portfolio composition;
3. VRE not impacted by coal generator mingens;
4. Snowy Hydro pump storage largely reflecting black coal to gas arbitrage; and
5. VRE generation economics reflects average spot prices received by VRE higher than their average cost.

4.5.2 Period 2025

When Snowy 2.0 enters in 2025, spot prices in SA-VIC-NSW would be expected to reflect a range from marginal coal generation prices to periods of high-priced coal generation and gas generation prices. Snowy 2.0 is largely trading between these prices.

Increased transmission by 2025 and possibly after that results in a narrowing of price differences between regions, and reduced spot price volatility (due to increased diversity) with the price differences reflecting power flow losses.

4.5.3 Period 2025 - 2040

As VRE increases and coal generation reduces, the profile of spot prices would be expected to reflect increased hours of surplus VRE and increased hours when 'firming' generation from gas generation or storage is required. As storage has limited energy it would tend to price its generation to shadow gas generation prices.

Further, uncertainty in price outcomes would have some batteries buying while others are charging. The amount of 'overlap' would be related to the cycle losses (which influence storage buy/sell spread) and the different outlooks of physical traders.

Increasing levels of storage would see increasing competition for supply from surplus VRE. The economics of batteries would require very high arbitrage revenues and it is unlikely that there would be a surplus of battery storage competing for VRE charging energy.

Gas generation would form an important component of firming and price setting.

The result is that over the period 2025 to 2040, Snowy 2.0 buying (ie pumping) prices would decrease and Snowy 2.0 selling (ie generation) prices would increase. This increasing spread combined with an increased volume of buying and selling has Snowy 2.0 net revenues increase (ie generation revenue less pumping costs).

4.5.4 Post-2040

Leading up to the closure of all coal plants in NSW (by 2044) the dynamic of the NEM will be radically changing. Very large quantities of storage would be required to support very high quantities of VRE, if VRE is to be economic. Based on the current cost of VRE and storage, the absence of a price or limit on emissions would limit the level of VRE that would be economic. Snowy 2.0 will provide for additional VRE generation.

The value of storage and the difficulty of 'efficient' NEM wide storage operation could result in storage operation being coordinated centrally, by AEMO. This could be with a voluntary service or mandated as part of revised market arrangements.

4.5.5 Post-2055

Under the assumption of a near-all-renewable power system with very large energy storage (for a given amount of capacity), spot prices would have little shape of volatility as the market would always clear from VRE generation or from stored VRE generation. However, this is not economically feasible.

The coal closures will be replaced by VRE, gas generation and storage. Pumping opportunities will increase while selling price may remain high or reduce by a moderate amount.

4.6 NEG and emissions policy

4.6.1 General

The Base Scenario assumes the current policy position, that there is no legislated emissions policy, applies for both pre- and post-2030.

The Low Emissions Scenario (see *Supporting Chapter Six*) assumed that NEG-type emissions arrangements would be the mechanism for implementing emission constraints (and this is described in the scenario).

There have been suggestions, and a level of agreement, that the reliability obligation of the NEG (or something close) be implemented. This section reviews that obligation and concludes that the modelling runs can be considered as being consistent with the implementation of such an arrangement.

This section presents:

1. The NEG rules for the reliability obligation and emissions obligation (as they stood when abandoned);
2. Implications for modelling if the rules were implemented; and
3. Other approaches to emissions abatement that have been considered.

4.6.2 Review of NEG Rules

Reliability Obligation

Key Features

1. Compliance is only applicable if the reliability obligation is triggered one year out; and
2. Compliance requires each retailer/large customer has contracted capacity equal to its share at the time of system maximum demand based on the system maximum demand measured ex-post, being at the 1 in 2-year level (ie penalty – based on cost).

Details of Rules

1. AEMO will assess reliability shortfalls through the ESOO process;
2. 3 years out if a reliability gap exists the reliability obligation will be 'set to trigger ':
    a. intended to incentivise liable entities through contracting and investment in resources to support the reliability of the power system;
3. 1 year out if a reliability gap still exists:
    a. the reliability obligation will 'trigger';

    b. concurrently AEMO will enable the Procurer of Last Resort safety net;
4. Once triggered (one year out) retailers and large customers may need to demonstrate compliance;
5. Large customers can have a retailer manage the obligation on their behalf;
6. If this were to be required, each retailer to undertake independent assessment of 'firmness' of contracts:
    a. Independent party to assess;
    b. Provide for Australian Energy Regulator (***AER***) to review;
7. Compliance:
    a. Only assessed if actual regional system peak demand (ie ex-post) exceeds that which would be expected to occur one in every two years;
    b. Assessment based on the qualifying contracts that contribute to system peak demand
    c. Penalty for non-compliance – (had not been developed);
8. A qualifying contract:
    a. The last draft of the NEG provided for derivative contracts with any party to qualify as a contract that could be used to compliance;
    b. Market liquidity obligation on large vertically integrated retailers:
        i. To ensure other liable entities have access to contracts; and
        ii. Imposed over a certain threshold (requirement to post bid and offers);
    c. Demand response products that qualify under the reliability obligation.

Emissions Obligation

Key Features

1. Annual obligation measured through contracts with generators for emissions + residual pool intensity for load not contracted;
2. Over-contracting of generation for emissions not allowed – proposed penalties; and
3. Non-compliance penalty – had not been developed.

Details of Rules

1. Annual obligation on retailers and large customers (commencing 2020/21) deadline each year for allocation is 31 October;
2. Generation and demand measured at each regional reference node;
3. First 50,000 MWh (5.7 MW average of any market customer's load will be exempt from the emissions reduction requirement (spread over other market customer load);
4. Average emissions intensity of a party's load is to be at or below the prescribed intensity target for each financial year compliance period;
5. An emissions registry to be used to allocate generator output and its associated emissions to a market customer's load:
    a. Parties can record allocations at any time during the compliance period; and

   b. Will also have four months after the end of the compliance period to continue to adjust their portfolios by recording reallocations;
6. Based on any contractual arrangement held with a counterparty and is separate to hedging contracts;
7. Registry will automatically match emissions to each market customer based on the generation allocated against their load;
8. Market customers that do not have generation allocated for some or all their load will be assigned the 'residual' emissions intensity of unallocated generation in the registry, in respect of their unallocated load;
9. Carry forward allowed and limited to:
   a. 5% of the emissions intensity reflected in the target for the first year of the emissions reduction requirement + a fixed amount of 60,000 t CO_2-e;
10. Behind-the-meter generation can be used:
    a. Rooftop PV – based on exports to grid;
11. Greenpower:
    a. Allow consumers to make an additional contribution to emissions reduction beyond that required by the target;
    b. Approach to additionality to be developed;
12. Over-allocation of generation by a customer not allowed:
    a. Overallocated amount assigned a deemed emissions intensity equal to the highest intensity generator in the NEM plus potential civil penalties;
13. Compliance:
    a. AER monitors and enforces compliance – framework to be developed;
    b. Each market customer will manage its reporting and compliance independently;
    c. 10% can be deferred to 2 years; and
    d. Penalty for non-compliance– one that is proportionate to the offence.

4.6.3 Other Emissions Abatement Approaches

Finkel Review

The following abatement mechanisms were presented in the Finkel Review:

1. Clean Energy Target;
2. Emissions intensity scheme (EIS);
3. Lifetime limits on coal-fired generators; and
4. Policy combinations.

Clean Energy Target

A CET would provide an incentive for all new generators that produce electricity below a specified emissions intensity threshold. All fuel types, including coal with carbon capture and storage (***CCS***) or gas, would be eligible for the scheme provided they meet or are below the emissions intensity threshold.

Eligible generators would receive certificates for the electricity they produce in proportion to how far their emissions intensity is below the threshold. New eligible generators would receive certificates for all electricity generated, while existing eligible generators could receive certificates for any electricity that they produce above their historic output. Consideration would also need to be given to the treatment of extensions to long-lived renewable assets like hydro.

Electricity retailers would be obliged to purchase these certificates to demonstrate that a predetermined share of their electricity came from low emissions generators. Provisions to prevent renewable generators from benefiting from both the LRET and the CET would need to be considered.

Emissions intensity scheme (EIS)

An EIS would see an emissions intensity baseline set for the whole electricity generation sector. Generators with an emissions intensity below the baseline would receive credits, while generators with an emissions intensity above the baseline would be required to purchase and surrender credits. Credits would be awarded or surrendered in proportion to how far a generator's emissions intensity is below or above the baseline, respectively. All generators, existing and new, would be required to participate in the scheme. Provisions to prevent renewable generators from benefiting from both the LRET and the EIS would need to be considered.

Lifetime limits on coal-fired generators

A lifetime limit would require coal-fired generators to close once they reach a certain age. The lifetime limit would be approximately consistent with the expected investment life of the generation asset. A lifetime limit of 50 years was modelled as a scenario for this Review.

Policy combinations

Combinations of a CET or an EIS with a lifetime limit on coal-fired generators were also considered.

There were no emission intensity-based prohibitions placed on new coal-fired generators under the scenarios modelled. This reflects the Review Panel's view that such a policy would not be effective in addressing cost, flexibility and security considerations.

5 Definitions and abbreviations

ADGSM	Australian Domestic Gas Supply Mechanism
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BNEF	Bloomberg New Energy Finance
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon capture and storage
CET	Clean Energy Target

CSG	Coal Seam Gas
DMLF	Dynamic Marginal Loss Factors
EIS	Emissions intensity scheme
ESOO	Electricity State of Opportunities
EV	Electric vehicles
FCAS	Frequency Control Ancillary Services
FID	Final Investment Decision
HELE	High efficiency, low emissions
ICE	Internal Combustion Engine
ISP	Integrated System Plan
LCOE	Levelised Cost of Electricity
LGC	Large-scale Generation Certificate
LNG	Liquified Natural Gas
LRET	Large-scale Renewable Energy Target
MJA	Marsden Jacob Associates
MLF	Marginal Loss Factors
NEG	National Energy Guarantee
NEM	National Electricity Market
PV	Photovoltaic
QRET	QLD Renewable Energy Targets
REZ	Renewable Energy Zones
SRMC	Short-Run Marginal Cost
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Targets

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