Ensuring reliable electricity supply in Victoria to 2028: suggested policy changes

Associate Professor Bruce Mountain and Dr Steven Percy

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Executive Summary

This report presents the results of modelling of the National Electricity Market (NEM) in the decade to 2028. It also critically assesses regulatory and market arrangements. The main question this report seeks to answer is whether, and if so how, policy should change to ensure the reliable supply of electricity in Victoria over the coming decade.

Our modelling concludes that over the decade, electricity production by Victoria's brown coal generators will be largely insensitive to the expansion of renewable generation in Victoria and elsewhere in the NEM. Renewables displace brown coal production. However, since emissions are not priced, brown coal generators produce electricity more cheaply than black coal generators and so the brown coal generators in Victoria displace black coal generators in New South Wales (NSW) and Queensland (QLD). A substantially faster (or slower) rate of renewable generation expansion than envisaged in current policies will have little impact on electricity production by Victoria's brown coal generators over the decade.

Using the Australian Energy Market Operator's demand, variable cost and power system technical specifications, our modelling finds that by 2028 several black coal generators in NSW and QLD will be operating at their minimum stable generation levels for around half the year. This is technically and commercially unsustainable and several of these black coal generators are likely to be mothballed or closed much sooner than their currently stated closure dates.

The (Commonwealth) Energy Minister has said that he is seeking that existing coal generators run "flat out". We have modelled this as subsidies to black coal generators in NSW and QLD so that they are able to offer their production to the market at a slightly lower price than brown coal generators. Yet in 2028 such a subsidy will still not be enough to encourage black coal generators to produce as much as they did in 2018. It will nonetheless result in substantially lower brown coal generation and this will greatly increase the risk of brown coal generator closure. A more literal interpretation of "flat out", for example maintaining aggregate black coal generation in 2028 at the level of 2018, would almost certainly result in the closure of two of Victoria's three brown coal generators.

To protect black coal generators, the Commonwealth Government may be tempted to slow down renewable generation expansion by erecting barriers to entry by, for example, supporting the AEMC's massively complex COGATI proposals. We expect this will raise prices and accelerate the rate of grid defection. Furthermore, we doubt existing coal generators will respond to such protectionist policy by investing to improve the capability and reliability of their coal generators in what is likely to be rapidly declining market.

Other than the reliability risk in Victoria attributable to possible Commonwealth Government policy to protect black coal generators, the main risk to reliable supply in Victoria is the demonstrated unreliability of all three of Victoria's brown coal generators, the concentration of fossil fuel supply in three stations with just 10 units amongst them, and their increasingly precarious social licence to operate.

For these reasons, ensuring reliable supply will depend on robust institutional arrangements and that are able to respond to change. Our assessment is that the existing market and regulatory arrangements do not achieve this:

- Firstly with respect to the mandatory spot markets, experts differ on whether such markets are able to ensure reliable supply. The many reviews and proposals over the last decade suggest that policy makers, regulators and market participants, by their actions, demonstrate little confidence in the NEM.
- Second, we think that the recently introduced Retailer Reliability Obligation will be ineffective. This is mostly because the majority of contracts that this obligation will deliver are simply internal contracts between the generation and retail arms of the same companies. This makes the appearance of compliance easy but the integrity of such internal contracts will almost certainly be impossible to police.
- Third, the Australian Energy Market Commission (AEMC) rejected the Australian Energy Market Operator's (AEMO's) sensible proposals to establish an effective reliability standard and strategic reserves. The absence of a reliability standard that takes account of the risk of outages is a significant defect in the institutional arrangements needed to ensure reliable supply.
- Finally, the AEMC recently introduced radical plans to change the NEM from a collection of five regional markets to (probably) hundreds of local markets. This will massively increase transaction costs. There are many reasons to reject these proposals not least because the case for such a radical change has not been made. It is particularly problematic that the AEMC has produced no evidence of a problem to be solved.

To ensure reliable supply we recommend the Government of Victoria ask AEMO to develop the full specification of the reliability standard and strategic reserve arrangements that AEMO had previously sought the AEMC's approval to develop. In parallel, the Government should consider administrative arrangements – whether rule changes or derogations – needed to ensure AEMO's recommended approach can be implemented in Victoria at short notice. Other states may also wish to pursue this approach and while coordination would be valuable (and preferable), Victoria should not wait on this.

Finally, we recommend in addition that:

1. Victorian Government policy support for new large-scale renewable generators should require that a proportion of production is firmed up through the installation of additional storage. Whether this is best done centrally or behind-the-meter should be examined.
2. The Victorian Government should consider accelerating the development of distributed and large-scale renewable generation and storage in Victoria to improve reliability and reduce prices. This may need to be accompanied by supporting transmission infrastructure such as synchronous condensers or synthetic inertia devices to ensure that the renewable generation can get to market.
3. The Victorian Government should consider a suite of policy changes to increase supply/reduce demand during weekdays from 6pm to 9pm. This might include changes to network tariffs, remote load control, the promotion of behind-the-meter batteries, the implementation of demand-side response schemes and incentives to orient rooftop solar to the west.

1 Introduction

This report has been prepared by the Victoria Energy Policy Centre, on its own initiative in pursuit of the objectives of its research program. The main question this report seeks to answer is whether, and if so how, policy should change to ensure the reliable supply of electricity in Victoria over the coming decade.

The report focusses on two separate areas. Firstly, it examines the markets and institutions and presents a critique of those from the perspective of the delivery of reliable supply. Second it analyses the market through the use of VEPC's NEM-CEED (National Energy Market, Capacity Expansion and Energy Dispatch) model. This provides insights into the likely evolution of the market over the coming decade and provides evidence of the nature and extent of the reliability challenge in Victoria in particular and in the NEM more generally.

The description and critique of markets and institutions is set out in Section 2. Sections 3, 4 and 5 then develop the market analysis initially through a description of the past (Section 3), and then a description of the present and near future (Section 4), and then projections and analysis to 2028 (Section 5). A concluding section draws out the main points followed by recommendations on policy changes the Government of Victoria might consider.

2 Market and institutions: description and critique

This section describes and critiques the institutional arrangements the affect the reliable supply of electricity in the NEM. It starts with a description of the mandatory spot market, the Retailer Reliability Obligation, the Reliability and Emergency Reserve Trader arrangements and finally the recently proposed Coordinated Generation and Transmission Infrastructure (COGATI) proposals.

2.1 The mandatory spot market

The mandatory spot market, often referred to as the "National Electricity Market" (NEM), is the main institution for the sale and purchase of wholesale electricity in the south and eastern states of Australia. Like all electricity markets, it is an administered market that did not arise organically. It has been in operation for 22 years.

The market is defined in the "National Electricity Rules" that started out, in 1996, as the "National Electricity Code" a 460-page rule book. National Electricity Rules are now in their 126th version and now run to 1,676 pages and many thousands of pages of guidelines related to these rules have been published by the Australian Energy Regulatory.

When it started, the National Electricity Code Administrator operated from Adelaide with a handful of staff. Now it is administered by the Australian Energy Markets Commission with a staff of 95 and annual expenditure of $27m. The annual budget for market enforcement and monitoring (by the AER) is likely also counted in the tens of millions of dollars. Despite the increase in the complexity of the cost, in fact there have been few substantive changes to the spot market since it was created.

The NEM is perhaps best described as a hybrid between an electricity pool – such as the one created in England and Wales in the late 1980s – and the integrated markets that started in the US around the same time as the NEM. Formally the NEM is a mandatory, centrally-settled final price spot market in which the system operator (AEMO) optimises the scheduling and dispatch of generation and calculates regional prices through the operation of a constrained, simultaneously feasible optimisation every five minutes. All contracts outside the NEM are *financial* (i.e., they provide commitments on price not physical production) and are, in one way or another, all contracts for the difference calculated relative to the spot market price.

By comparison with electricity markets elsewhere, the NEM is an unusual market in many ways. Firstly it is an energy-only market without any form of capacity payment or strategic reserve, one of only a few such markets left (New Zealand and Texas being the others). Electricity markets in other countries usually compensate both energy and capacity.[1] Secondly it is a *mandatory* short-term market (again New Zealand is the only approximately comparable market). Certainly Australia is the only market dominated by thermal generation that is also a mandatory energy-only market. Other integrated markets (which are typically in the US) combine day-ahead markets where participants can voluntarily trade physical or financial contracts, and which are then taken into account in the settlement of imbalances in spot markets. This is the standard market design in the US and elsewhere, except Europe, and has proven to be successful (O'Connor and O'Connell-Diaz, 2015).

The most challenging objective for electricity markets is the provision of incentives for efficient long-run investment (Cramton, 2017). As an energy-only market, the incentive for investment arises when prices rise above production costs. However the ability to raise prices far above production costs also incentivises the abuse of market power in the absence of demand elasticity (Stoft, 2002). For this reason, prices in any half-hourly trading period in the NEM are capped (at $14,700/MWh) and average prices over a rolling period of 336 half hour settlement periods are capped at $300/MWh. These caps give rise to a concern of "missing money", which can be defined as the lost earnings beyond the price cap, especially for peak load power plants (Bublitz et al., 2019).

"Missing money" may also occur due to premature technical decisions of system operators to avoid market disequilibrium and brownout (Joskow and Tirole, 2007). On the other hand (Newbery, 2016) argues that even if earnings from price spikes are sufficient to cover fixed and capital costs, investors might not be willing to bear the associated risks. In this case the problem is referred to as missing markets instead of missing money (Newbery, 1998). By contrast (Cramton, 2017) suggests energy-only markets can provide the investment incentives for battery storage and improved demand response as the share of renewable resources grows. He argues this on the basis that energy prices will become highly volatile, and batteries, demand response, and gas peakers are well-positioned to profit from this volatility, buying when prices are low and selling when prices are high.

For most of its history, the main mechanism to ensure reliable supply in the NEM has been the level of the Market Price Cap, which is decided by the AEMC (on advice from the Reliability Panel) and has risen from $5,000/MWh when the market started to $14,700/MWh today (as noted earlier).

While it is not our intention to evaluate the arguments on whether an energy-only market is able to provide reliable supply, we provide a brief precis of the main arguments in the literature drawing on (Bublitz et al., 2019). The seminal early works on energy only markets (EOM) (Caramanis, Schweppe and Bonn, 1982; Schweppe et al., 1988), stressed that EOM would ensure sufficient long-term investments guaranteeing the least-cost long-term system if the market is perfectly competitive, market participants are rational and risk-neutral (amongst other demanding assumptions).

However, in practice, a small number of producers often dominate the market (this is particularly the case in the NEM) resulting in a duopoly or oligopoly (e.g., Schwenen, 2015; Mountain and Percy, 2019), or invest strategically (Grimm and Zoettl, 2013). Furthermore, investors are usually rather risk-averse (i.e., building less capacity than risk-neutral investors would) (Neuhoff and De Vries, 2004). And with uncertainty (for example on future prices) and long lead times for new investments, electricity markets are prone to suffer investment cycles. Neuhoff and De Vries (2004) argue that even long-term contracts do not provide a solution as they offer consumers the opportunity to free-ride. Keppler (2017) shows in addition that demand-side externalities in the form of transaction costs and incomplete information ensure that the

1. Bublitz, Keles and Fichtner, 2017 produces a helpful taxonomy distinguishing markets that centrally procure capacity (4 of the 6 U.S. markets, Colombia, Ireland, Italy, Poland the UK) that operate strategic reserves (Belgium, Germany and Sweden) and that have decentralised capacity obligations (France, two of the six U.S markets, the South West Interconnected System).

social willingness-to-pay is greater than private willingness-to-pay for additional capacity. On the other hand, investments in generation capacities are not arbitrarily scalable, but rather take discrete values. In combination with dramatically lower revenues in the transition from underinvestment to over-investment, investors have strong asymmetric incentives and thus tend to under-invest rather than to over-invest.

While some (e.g., Besser, Farr and Tierney, 2002) argue that the issue is a lack of political will to allow for unconstrained electricity prices and periodic shortages and that this undermines the effectiveness of EOM, others (Joskow and Tirole, 2007) argue that scarcity rents are very sensitive to regulatory changes and that even minor mistakes are likely to have a significant impact on market prices. Cramton and Stoft, (2005) and Joskow and Tirole (2007) also argue that market imperfections, especially the lack of demand response, will always persist in EOMs and lead to the exercise of market power which results in high price peaks.

A structured debate is yet to be had in Australia on the merits of an energy only market (no doubt it will feature as part of the Energy Security Board's review of market arrangements to apply from 2025). However, we suggest that there is little room to doubt that policy makers, regulators and the industry believe that the current market fails to ensure reliable supply. For example, we are unable to identify any policy maker, regulator or industry participant who suggested that the reliability proposals in the Finkel Review (Finkel et al., 2017) (discussed below) or the Retailer Reliability Obligation of the National Energy Guarantee (discussed below) were unnecessary because the existing market was working well. The closest to a defence of the status quo can be found in the AEMC's rejection of AEMO's Reliability and Emergency Reserve Trader rule change application (discussed below).

The Finkel Review in 2017 was the first substantive independent review to propose substantially different arrangements to ensure reliability. Specifically, it suggested strengthening AEMO's role as a provider of strategic reserves (with suitably designed reliability standards) and also proposed obligations on new entrant variable renewable generators to "firm" a proportion of their production. This recommendation was however superseded by the Retailer Reliability Obligation of the National Energy Guarantee (NEG), described and reviewed below. The Finkel Review recommendation on reliability standards and strategic reserves was taken up in a rule change application by AEMO (discussed below).

2.2 Retailer Reliability Obligation (RRO)

The RRO entered into force on 2 July 2019 and is specified in 16 additional pages to the National Electricity Law, 56 additional pages of the National Electricity Rules and six new guidelines (four of which exist in Draft Form and currently number over 300 pages), which will be finalised by the end of 2020.

The RRO was proposed by the Energy Security Board, an advisory body appointed by the Council of Australian Government's Energy Council. The RRO was initially proposed as part of the NEG in 2017. The initial proposal was for a scheme that would exist outside the wholesale market and which would oblige electricity retailers to enter into physical contracts with dispatchable generators to meet a proportion of their expected peak load. The NEG proposal was not developed following a process of discussion and consultation but arose unexpectedly when it became clear that the then Australian Government would not accept the main recommendation of the Finkel Review (for a mandatory certificate scheme).

The RRO is best described as a decentralised reliability obligation in the sense that the obligation is placed on retailers rather than producers. Retailers are obliged to hold a quantity of qualifying financial contracts that are sufficient to match their share of the level of forecast demand that has a 50% chance of being exceeded, during defined reliability periods. Such reliability periods are first predicted three years in advance and if they are still predicted a year in advance, the obligation is invoked.

Qualifying contracts can take many forms including swaps, caps, options, load following contracts, Power Purchase Agreements (PPAs) and intra-company contracts. A major complexity that arises with this approach is that contracts in the NEM are necessarily *financial* (the contracts are in one form or another referenced to the spot price). This means that to derive the "firmness" associated with different forms of contract it is necessary to specify methodologies that define the amount of physical capacity it is appropriate to associate with each contract. The methodology for a number of contract types are specified in guidelines. However the vast majority (probably more than three quarters of all contracts) will be bespoke contracts. This is because the vast majority of electricity that is sold in the NEM is sold by the same company that produces it. In other words the great majority of the contracts that the retail division of the company are required to hold to meet their RRO obligations, are contracts with the generation division of the same company. The methodology for determining the physical capacity of such intra-company financial contracts is "bespoke". Auditors appointed by the companies from a panel approved by the AER are required to develop these "bespoke" methodologies and the AER is required to accept their methodology (and its results) in the absence of "manifest error".

The RRO is consistent with the exceptionalism of Australia's energy market. Decentralised capacity obligations are rare in electricity markets. The arrangements adopted in France are the closest comparator, although they are very different. The French electricity market is not a mandatory market and so the reliability instrument in the French market is a certified level of physical capacity and is determined without the need for the complex arrangements in the NEM to estimate the physical capacity to be associated with financial contracts.

2.2.1 Critique

We argue the RRO will not improve the reliability of the NEM. We reach this conclusion from first principles and an analysis of the demand and supply that the mechanism creates.

First principles

The ESB has suggested that the obligation to demonstrate firm supply in order to meet demand (both as defined by the RRO) will stimulate investment. However, the RRO does not require retailers to enter long-term contracts or even to maintain this contract position once they have submitted their compliance statement to the AER. In fact the contracts will cover merely a subset of trading intervals within a defined reliability period which will be even shorter than the one year (or shorter) price hedges that are common in the NEM. We suggest short-term contracts hedging prices for a few five-minute trading intervals[2] and that exist only for the purpose of satisfying a regulatory obligation will not meaningfully improve revenue certainty for generators. Hence we conclude from first principles that it is implausible to suggest that such short-term contracts will make long-lived generation investment any more likely.

Demand side

The RRO requires retailers to demonstrate sufficient quantity of qualifying contracts to meet their share of actual system load scaled down to the level that is likely to be exceeded every second year. But power systems are only likely to be unreliable when demands on them are very high (i.e., far above the level that is likely to be exceeded every second year). Establishing an obligation that is not related to actual demand but instead a much lower level of demand means that on the demand side the RRO fails to establish the scarcity that it is intended to address.

2. The duration of reliability events it not known, but in RRO documentation, examples suggest a few hours per day during week days for a couple of months.

Supply side

On the supply side, the RRO tries to measure the likely actual physical production (during five-minute trading intervals) associated with a variety of forms of financial contracts. As noted, these contracts in one form or another reference the spot price since the NEM is a mandatory centrally-settled mandatory market). As we pointed out in our report on the NEG (Mountain, 2018), it is impossible to objectively estimate the physical supply associated with financial contracts.

In our critique of the initial version of what was then known as the reliability arm of the NEG, we pointed out that the attempt to discern the physical supply associated with a financial contract is unavoidably subjective: there is no way that a financial contract that does not bind the seller to physically produce electricity, can be claimed to deliver firm production. The ESB's initial Technical Working Paper did not explain how retailers were to infer the firm physical production associated with a variety of different financial contracts (it identified swaps and caps, interregional contracts, load following contracts, fixed shape swaps, options, weather contracts, tolling agreements, power purchase agreements and demand response products). Instead of providing guidance on how to infer the physical capacity associated with these different contracts, the ESB referred to a "framework approach" (whatever that means).

The AER's guidelines now describe how the AER will determine the "firm" physical supply associated with various types of financial contract. The underlying idea is that the probability that can be placed on a financial contract's ability to translate into physical production is measured by the extent to which that contract insulates against spot prices. So, swaps and load-following contracts have a firmness factor of 1 (i.e. these financial contracts are assumed to translate into physical production MW per MW of contract because they insulate completely against spot prices). This seems reasonable but estimating the firmness becomes far more complex for all other types of contract. For example, for options it relies on option valuation models (and the measurement of the volatility of the underlying instrument) in order to establish the likelihood of an option being exercised.

In the case of inter-regional contracts assumptions need to be made on interconnector constraints and the extent to which the parties have hedged those constraints. In the case of PPAs, assumptions need to be made on how sunny or windy it will be during the future reliability events (in the case of variable renewable generators) or the likelihood of outages (in the case of fossil-fuel generators). None of this can be established with certainty (it relies on assumptions of future production), and the buyers of these contracts have powerful incentives to overstate availability and capacity since this demonstrates compliance and avoids the burden of contracting for additional capacity.

The most significant problem however lies with the intra-company contracts that the vertically integrated retailers will need to arrange with their generator divisions. The majority (probably more than 75%) of the electricity produced in the NEM is sold by the same firm[3] that makes it. In respect of such production, the RRO therefore establishes an obligation on liable entities to contract with themselves for the purpose of demonstrating that the retail arm of the firm has enough firm supply to match its share of a one in two-year demand.

Such internal contracts have no commercial meaning (a contract with yourself establishes no net liability). However, the RRO establishes a compliance demand for such internal contracts – the retail arm of the gentailer submits the contracts to the AER to prove that it has sufficient firm supply to meet the RRO's demand). Both "parties" to such contracts have an incentivise to overstate the firm capacity to be associated with the contract (by for example assuming fossil fuel capacity will always be available at its rated capacity and renewable capacity will have favourable winds and sun, and inter-regional capacity will always have firm access to interconnectors and so on).

3. These are commonly referred to as "gentailers", a portmanteau of "generators" and "retailers".

The AER (or any other regulator) will be unable to assess the validity any related-party contracts in isolation of all other contracts that either the related party generator or retailer has struck. The feasibility of an individual contract can only be assessed through the calculation of the simultaneous feasibility of all the gentailers' contracts: how can the AER assess that a financial contract is physically backed unless it adds up all the financial contracts and checks the aggregate against the physical capacity of the counter-parties?

ESB representatives assured us that this was easily done and that retailers were well acquainted with audits and assessments of their trading positions to satisfy the risk requirements of their Boards and the Australian Securities and Investment Commission. Audits or risk management assessments to calculate a meaningful commercial risk associated with trades with independent third parties is one thing. But audits of internal contracts concocted solely for the purpose of satisfying an obscure regulatory obligation is another. This is particularly so when the auditors – hired by the management of the company – are free to develop their own methodologies to estimate the physical capacity associated with bespoke contracts and those methodologies are not subject to challenge by the regulator other than for "manifest" error.

Essentially therefore, we suggest the estimation of firm supply through this process is likely to substantially overstate the actual firm supply. On the supply-side therefore we conclude, as for the demand-side, the RRO is unlikely to properly represent the scarcity that it is purports to represent.

Summary

In discussion with us, ESB representatives did not agree with our criticisms. However they stressed in addition that the underlying intent of the mechanism was that it would signal future scarcity and it was only if market participants failed to respond to this by increasing supply that the RRO requirement to purchase qualifying contracts would be invoked. The success of such a "sword of Damocles" approach depends on a credible threat. Our conclusion from first principles and an analysis of both the demand side and supply side, is that the RRO does not present a credible threat and the Government of Victoria cannot rely on it to ensure reliable supply in Victoria.

2.3 Reliability and Emergency Reserve Trader (RERT)

Since it was established, the NEM has incorporated a mechanism for the system operator to purchase reserves that are supplied outside of the mandatory spot market and used in emergency situations when the demand and supply balance is tight, in order to avoid expected involuntary load shedding.

The RERT was implemented in 2008, replacing the hitherto unused "reserve trader" provisions. While the RERT was designed to sunset in 2016, the AEMC extended it indefinitely but with a curtailed scope and a restriction on the advance notice that AEMO had to procure reserves (to no more than 10 weeks). AEMO requested longer notice periods in 2018 and the AEMC agreed to extend the maximum notice to nine months which increases to 12 months with the introduction of the RRO.

Before 2017, generation procured under the RERT (on three separate occasions) had never been dispatched. On 30 November 2017, resources procured under RERT was dispatched in Victoria for a total cost of $0.9m. On 18/19 January 2018 it was dispatched again in Victoria and South Australia for a total cost of $24.1m. On 24/25 January 2019 it was again dispatched at a total cost of $34.2m in Vic and SA (Australian Energy Markets Commission, 2019).

When RERT is activated, spot prices in the market are recalculated as if was not dispatched, so that consumers pay higher prices and producers are protected from the competition that the RERT capacity has presented in the mandatory spot market.

The Finkel Review (Australian Energy Markets Commission, 2019) supported the expansion of RERT so that AEMO could establish standing reserves and so that AEMO was not restricted by the length of the notice of RERT capacity it contracted. AEMO subsequently (in March 2018) asked the AEMC to change the RERT rules to allow AEMO to:

- procure reserves up to three years in advance of their possible use, and
- assess reliability risk on the basis of probabilities and value of lost load rather than estimates of unserved energy (as now). Specifically, this means a fundamental re-consideration of RERT as akin to insurance against extreme outage risks.

Furthermore, AEMO suggested an economic criterion: if reserves were available and these could be dispatched at a price between the market price cap and the value of unserved load, it would be sensible to procure such reserves.

2.3.1 Critique of the AEMC's rejection of AEMO's proposals

The AEMC substantially rejected AEMO's proposals. The main rationale for the AEMC's rejection were that:

- AEMO was intrinsically risk averse because AEMO has more to lose if the lights go out than it has to win if the lights stay on ("over- procurement is costly for consumers but not for system operators whereas under-procurement would be costly for system operators and consumers"). This, the AEMC argued, provides a tendency to over-estimate reliability risks at customers' expense.
- The "high impact low probability" risks that AEMO describes as the basis of its recommended approach to the provision of reliability should not be taken into account because rotational load shedding means that such risks do not exist.
- The AEMC's consultant concluded that many of the overseas markets that AEMO suggested had superior reliability planning standards to those in the NEM, are in fact too reliable, at customers' expense.

The AEMC's reasoning underlying the AEMC's rejection of AEMO's RERT proposals is unconvincing. Firstly, we agree with AEMO's critique that the existing expected unserved energy standard fails to account for the differing impact of unserved energy, depending on the extent of those outages and the conditions on the system at the time of those outages.

The AEMC does not have a good answer for this criticism, specifically:

1. The claim that rotational load shedding avoids high impact low probability events implies a much higher level of power system control than actually exists.
2. The AEMC seems to have rejected AEMO's adverse comparison of the NEM standard with the reliability approaches adopted in other countries based on the advice of its consultant that in the four markets it examined, more reserves were procured to meet reliability standards than needed. Whether or not this is the case does not address AEMO's fundamental concern that a standard based on the expected volume of unserved energy fails to consider appropriately the risks associated with that unserved energy.
3. Finally, the AEMC's analysis of the political economy of outages fails to account for the recovery of the costs of reserves and the vociferous activism of those that bear this cost (which vociferous activism the AEMC repeatedly cites in support of its rejection of AEMO's proposals).

It would seem to us that underlying the AEMC's rejection of AEMO's proposal is the concern (Joskow and Tirole, 2007, cited earlier) that "premature technical decisions of system operators to avoid market disequilibrium and brownout may lead to "missing money"". In other words, by increasing the supply of strategic reserves outside of the mandatory market spot market – as AEMO effectively seeks – the ability of the mandatory spot market to provide sufficient revenues to attract investment would be undermined. But the legitimacy of this concern is undermined by the overwhelming evidence that policy-makers, regulators (including the AEMC) and market participants lack confidence in the existing market's ability to provide the investment certainty needed to attract investment, particularly in rarely used peaking capacity.

2.4 Cogati

The AEMC has recently released proposals for fundamental changes to the market design, which it calls the "Coordinated generation and transmission infrastructure" (Cogati) access model. The proposal is to replace the current five regional markets with an undefined number (probably hundreds) of locational markets. Generators, storage and other scheduled and semi-scheduled market participants would receive a locational price for the electricity they sell to the grid. Retailers and other non-scheduled market participants would continue to be settled at the regional prices based on the volume weighted average price of electricity sold at the nodes in each region.

In addition, "Financial Transmission Rights" (FTR) which formally are financial options, would be sold by AEMO (based on transmission capacity as defined by Transmission Network Service Providers) as a way for market participants to hedge the financial risk they face based on the difference between nodal and regional prices, and between nodal prices. These FTRs are meant to reflect the marginal cost of transmission congestion (and transmission losses) at each node on the system.

The options will be auctioned each quarter for electricity transacted quarterly up to four years ahead. The auctions will need to be simultaneous feasibility auctions since the quantity of one particular FTR having sold would impact on the quantity of FTRs available to be sold between all other nodes and between nodes and regions. Buyers of locational FTRs will be limited to physical market participants and up to some measure of their capacity. Buyers of regional FTRs may include financial market participants.

The AEMC asserts that its proposal is a "holistic long-term solution to many of the issues raised by generators, retailers, storage operators, investors, consumer groups and market bodies".

2.4.1 Critique

If it is implemented COGATI will be, by a long way, the biggest change to the wholesale market since the creation of the NEM in 1998. The rationale for this approach in theory lies in orthodox neoclassical economics: that setting prices equal to marginal cost will deliver the efficient allocation of resources.

COGATI seeks to achieve this at hundreds of "nodes" on the transmission system. By paying generators the prices at these nodes, it is claimed that this efficiently compensates production taking account of its ability to get its produce to market. In this theory, generators are therefore incentivised to locate at the points on the power system where it is most likely that their produce will be delivered to market. Such "locational marginal price" arrangement is not a new idea in the theory of electricity markets. It has been implemented to varying degrees in a few electricity markets around the world but rejected by the vast majority. The idea has bubbled up for consideration in the NEM at various times in the past, its proponents usually being those with a strong, almost ideological attachment to early neoclassical orthodoxy.

We think the arguments for COGATI are weak and suggest that it should be summarily rejected by policy makers. We argue this on the basis firstly that the foundation in theory is weak; that the case for change has not been made; that COGATI allocates transmission risks to the wrong entities; that COGATI will further entrench market power; that COGATI will unfairly advantage incumbents; that COGATI will undermine governments' renewable electricity policy and finally above all else that it is extremely complex and will massively increase wholesale market transaction costs. The rest of this sub-section sets these arguments out.

The theoretical foundations are weak

COGATI rests on orthodox neoclassical economics – that prices based on marginal costs are efficient. As is well-known, this theory rests on many unrealistic assumptions: that buyers and sellers are rational, that there is perfect foresight, that there are no economies of scale or lumpiness in capacity expansion, that there are no transaction costs, that demand is elastic and so on.

While slavish conformity to this orthodoxy might have been tolerable in the absence of broadly accepted alternatives, alternative perspectives are now well established and the AEMC should be expected to demonstrate an appreciation for them and to develop proposals that reflect the insights of these other perspectives. For example:

- Transaction Cost Economics (Coase, 1937; Williamson, 1975, 2007; Goldberg, 1976; Crocker and Masten, 1996), would have suggested that transaction costs should be critical in considering the design of an electricity market. Specifically in the context of large (imposed) transaction costs, vertical integration is far more likely and this can pose a barrier to effective competition in retail and wholesale markets by making entry to both more difficult. The seems to be exactly what New Zealand's experience with locational pricing demonstrates
- Austrian economics provides the concept of markets as processes for the discovery of consumers' wants and needs (Kirzner, 1997). This provides a valuable alternative to the obsession with prices that match marginal costs and is well accepted in the analysis of competition and the design of markets (Littlechild, 2018).
- Behavioural economics (Pollitt and Shaorshadze, 2011), elaborates concepts such as status quo bias and bounded rationality that again would lead to very different decisions on the design of electricity markets than those that reflect a narrow pursuit of prices based on marginal costs.

The case for change has not been made

The case for splitting the NEM into (probably) hundreds of locational markets rather than its current five is that the prices in the current regional markets – being set at the regional reference node of each market – fails to adequately establish the value of electricity in each market. In other words, that there are frequent and deep intra-regional transmission constraints that if taken into account, would result in very different production schedules and prices than currently occur.

If this is indeed the case now or, in the foreseeable future, then this would provide a reason for considering changes to the market, including changes such as COGATI. The starting point in making the case for change is therefore to establish that there are frequent and deep intra-regional constraints and that this will now or in the future result in frequent and large mis-pricing. Establishing this for the present is easily done[4] by comparing the prices and production that actually occurs in the market, with the prices and production that would occur assuming no intra-regional congestion.

4. We recognise that in this calculation various complexities need to be grappled-with including differences between actual and ex-post unconstrained dispatch associated with transmission losses, demand forecast error and system stability constraints unrelated to transmission congestion.

The AEMC has not done this. Instead the AEMC note that in future generation will increasingly be located in parts of the network that are distant to existing generation and so the system will necessarily be constrained and so the current regional market structure should be abandoned. But there is no basis for this assumption other than that transmission planners, the transmission operator and other decision makers will not organise the extension of transmission to new renewable generators located in places that generation has not historically located. Why, a priori, should we expect this to be the case?

A change to the market of the size and complexity that the AEMC is proposing with COGATI demands evidence of a problem to be solved. Simply asserting a problem, as the AEMC has, is inadequate.

CoGATI allocates congestion risk to the wrong entities

COGATI allocates the risk of transmission congestion to producers. We argue that this is a poor allocation of congestion risk.

Electricity generation and transmission are complements and substitutes: generators depend on transmission to get their production to market, but transmission can also substitute for generation (for example, expanding transmission to an existing generator can affect the demand available to a new entrant generator). This substitute/complement duality is not unique to electricity but common to many other network industries (for example dams and water pipelines, gas producers and gas pipelines).

The separation of transmission from generation – a necessary condition for the creation of a market in generation – precludes central coordination of the development of generation and transmission. This is well understood by those that decided to create wholesale markets and the argument (in economics) for such market is that the efficiency gains from competition in production exceed the losses from central coordination of the development of generation and transmission.

The residual question: how to allocate the risks associated with transmission congestion is complex and a wide variety of plausible approaches can be pursued. The locational marginal pricing approach – such as COGATI – allocates transmission congestion risk to generators by defining the markets in which generators compete as a function of transmission congestion.

A commonly accepted heuristic of risk management is that risks should be allocated to the parties best able to manage them, and if such parties can not be identified, then they should be allocated to the parties best able to bear them. Generators have limited ability to manage congestion risk. New entrants might be able to manage congestion risk by not locating in congested parts of the network. But existing generators can not simply relocate. Generators could potentially invest in transmission themselves but this is extremely difficult for many reasons not least:

1. that alternating current flows are not controllable (it is only possible to establish physical property rights in transmission on direct current circuits – whose power flows are directly controllable)
2. that capacity increments are lumpy (transmission operates at a few discrete voltages)
3. because ensuring wholesale competition requires third party access to that transmission, and
3. because there are enormous economies of scale in transmission (because the power carrying capability of a line rises as the square of its voltage, which cost is linear with voltage).

For these reasons, “merchant” transmission in a meshed network (i.e., other than Direct Current [DC] interconnectors) does not exist. Even Australia’s experiment with two merchant DC interconnectors (Riverlink and Directlink) saw both such interconnectors beat a hasty retreat to regulatory protection under “safe-harbour” provisions, shortly after they were built.

Generators, very obviously, have limited ability to manage congestion risk. For this reason, the default is for congestion risk to be managed by transmission operators and transmission asset owners. In Britain an incentive for the grid operator (and owner) to manage congestion was developed by the industry and subsequently managed by the regulator in 1996 and has continued since.[5] In Australia, the AER introduced uplift management incentives around five years ago to encourage network service providers to reduce congestion. While this scheme leaves much to be desired it does at least correctly identify one of the parties able to manage transmission congestion (the network owners) and provides some incentive for them to reduce congestion.

The AEMC has provided no justification for the risk allocation it proposes. For the reasons set out here, allocating congestion risk to producers as the AEMC proposes, will allocate risk to entities that in almost all cases have no ability to manage those risks.[6] This explains at least in part why COGATI-like approaches have had so little uptake in power markets around the world in the 30-odd years that they have been discussed.

COGATI will further entrench market power

From first principles, a producer is better able to exercise market power (by raising prices far above production costs) if it does not face competition. Nodal/locational markets will, by definition, have fewer competitors than larger regional markets. From first principles, the prospects for the exercise of market power are likely to be enhanced in nodal rather than regional markets. Evidence from the study of the locational markets in California (Woerman, 2018) finds exactly this. By contrast the AEMC simply asserts that market power is not likely with its proposed locational markets.

COGATI is likely to advantage fossil-fuel incumbents

The transmission infrastructure in the NEM has been oriented around the exploitation of the fossil fuel resources in closest proximity to the capital cities of each state.[7] Exploiting solar and wind renewable production will require the extension of this infrastructure to new areas in each state. By virtue of this historic legacy, it is much more likely that new entrant renewable capacity rather than existing fossil fuel capacity, will face congestion risk. Some might argue that it is correct that new entrant generators bear the congestion risks that arise from locating in unfavourable parts of the network. But there is no objective correctness to this argument: it rests only on the subjective perspective that the legacy should be protected from the new. While there is equally no objective correctness to the argument that new entrant generators should enjoy the same benefits that existing generators have, the implementation of COGATI means that existing fossil-fuel generators will enjoy advantages relative to new entrant generators. It is difficult to imagine that policy makers intent on encouraging investment in renewable generation would be seeking such an outcome.

COGATI will undermine state governments' renewable energy policy objectives

All of Australia's jurisdictional governments have set policies that seek to expand renewable electricity production. The implementation of COGATI will deliver market arrangements that are very much less conducive to such new entry than is the case with the existing market. Other than exposure to congestion risk (explained above), new entrants no longer need to predict the regional price in which they will be located, but instead they will be required to predict the locational price (and the cost of transmission rights) at whichever of hundreds of possible nodes they will be connected to. Without an established market at such nodes, the ability for investors to analyse and predict prices at such nodes will be much

5. The author was responsible for advising the Office of the Electricity Regulator the first regulatory control.
6. We recognise that in the existing regional market, generators are already to some degree exposed to congestion risk through the prospect of not being dispatched when caught on the exporting side of a transmission constraint. However, this risk exposure is very much less than the exposure they would face if markets were defined at each node rather than regionally.
7. Excluding Tasmania of course.

diminished relative to their ability to do this at the few regional reference nodes that currently exist. The absence of such market knowledge will be expressed in much higher revenue risk and necessarily a much higher cost of capital to compensate those risks. Relative to the status quo this will result in lower entry for the same capital outlay or alternatively in necessarily higher prices for the same level of entry.

COGATI is extremely complex and will massively increase wholesale market transaction costs

Electricity markets are complex engineered markets that do not spontaneously arise. The introduction of locational prices based on congestion and transmission losses and the introduction of financial transmission rights will massively complicate what is already a very complex market. It is notable that despite describing its proposal as "holistic long-term solution to many of the issues raised by generators, retailers, storage operators, investors, consumer groups and market bodies", the AEMC's proposals only elaborate locational prices based only on congestion, and the AEMC has not made any progress in identifying how its proposals will take account of losses (which will almost certainly account for far more of the locational price variation than congestion).

The main sources of complexity associated with the implementation COGATI we expect in the following areas:

- Changing the settlement and market systems system to account for hundreds of locational rather than a handful of regional prices
- The arrangements for the primary allocation of financial transmission rights and then secondary trade in those rights
- Developing the rules and guidelines needed to implement locational prices and financial transmission rights, and
- Developing and implementing the monitoring, compliance and enforcement activities.

2.5 Wholesale market governance

In this subsection we describe and briefly critique wholesale market governance. The purpose of covering this here is not to present a fulsome analysis of market governance, but rather to provide a sufficient basis to conclude whether (or not) flaws in existing market governance arrangements help to provide support for our recommendations.

Market governance in the NEM can be described in the terms of its main actors: the jurisdictional governments, the Commonwealth, the Council of Australian Governments Energy Council (COAG EC), the Australian Energy Markets Commission (AEMC), the Energy Security Board (ESB), and the Australian Energy Regulator (AER).

- **Jurisdictional governments** are responsible for electricity supply within their jurisdictions. As signatories to the Australian Energy Law they have however (largely) ceded control of the electricity markets within their jurisdictions, to the multi-party governance established through the law. Jurisdictional governments can (and do) however derogate from the law (and the National Electricity Rules under the Law).
- **The Commonwealth** does not have direct control over the supply of electricity within the jurisdictions. However through its ownership of Snowy Hydro, the Australian government is a major supplier of peaking generation, and through Snowy Hydro's ownership of Red and Lumo, the Australian Government is also one of the largest retailers of electricity in the NEM. In chairing the Council of Australian Government's Energy Council, the Australian Government also a significant, if not leading role to play in national (or regional) coordination of electricity supply.

- The **Council of Australian Governments Energy Council (COAG EC)** is one of 10 COAG councils. Under the COAG council system, decisions are normally made by simple majority, but COAG decisions are not binding on members that did not vote for those decisions. Unlike the other Councils, COAG EC provides a forum for collaboration and decision making on an industry that at least in the south and eastern states is physically interconnected, centrally operated, and whose produce is traded in a single mandatory centrally operated market.
- The **Australian Energy Markets Commission (AEMC)** has two roles: firstly to establish and decide the National Electricity Rules and secondly to advise COAG EC. In its capacity as the entity that both decides the National Electricity Rules and has a (non-exclusive) advisory role to COAG EC, the AEMC is arguably the most important of the various actors that define the governance of the electricity market.
- The **Energy Security Board (ESB)** was ostensibly created to implement the recommendations of the Finkel Review, but in practice its most significant involvement has been to promote the NEG proposed by the Minister for Energy in the Australian Government and, after the Australian Government changed its mind on the NEG, to oversee the development and implantation of the "reliability arm" of the NEG (i.e., the RRO described earlier). Representing the chairs of the AER, AEMC and AER but with an independent chairman and deputy chairman, the ESB now has a role as an advisor to COAG EC and its main role now is to propose market arrangements to apply from 2025.
- The **Australian Energy Regulator (AER)** was created in 2004 as an agency tasked with the economic regulation (as designed by the AEMC) of network monopolies, and with roles in monitoring and enforcing compliance with the Rules. The AER has no meaningful role in the design of wholesale markets and has a limited role in their governance.

2.5.1 Critique

The last major review (in 2015) of the governance of Australia's energy markets declared, in the first sentence of its report, that the governance of the NEM was "amongst best practice internationally"[8]. This view would not now seem to be widely shared. Often quoting industry or regulator representatives Australia's newspapers frequently report on a market that it is described as "a mess"[9], "costly chaos"[10], "a tortured debate"[11], and so on and on.

Having regard to the focus of this critique, the stand-out governance problem seems to be the combination of a body (COAG EC) that represents energy ministers but that has no executive authority and whose decisions are not binding on members that did not vote for them, and the AEMC which combines roles as advisor to COAG EC but also being the decision-maker on the National Electricity Rules.

Even if COAG EC members agree a particular course, they need to make application to the AEMC to implement their decision if this requires changes to the National Electricity Rules, as will usually be the case. The AEMC then decides whether such rules should be enacted, and the AEMC has no accountability to policy makers for its decision.

While jurisdictions can decide to opt-out of rules set by the AEMC (by derogating from them) they have no means of executing their agenda (if this requires rule changes) unless the AEMC agrees to their proposals.

8. http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Review%20of%20Governance%20Arrangements%20for%20Australian%20Energy%20Markets%20-%20Final%20Report%20-%20Oct%202015.pdf
9. https://www.afr.com/companies/energy/australias-energy-policy-is-shipwrecked-on-the-same-reef-again-20181001-h163p5
10. https://reneweconomy.com.au/there-are-no-winners-from-australias-costly-energy-chaos-25789/
11. https://www.theguardian.com/australia-news/2019/oct/13/australias-tortured-energy-debate-what-is-the-state-of-play

We think much of the explanation for the ossification that characterises the governance of the wholesale market can be traced back to the poor accountability associated with the AEMC's role as both policy advisor and also final decision maker. Our assessment is that this governance failure jeopardises the market's ability to evolve efficiently in response to technology changes and new information. Mitigating this failure justifies, in part, policy responses by individual jurisdictional governments to protect the public interest in their jurisdictions, for example in respect of reliable supply, as we recommend in this report.

3 Supply and demand in the NEM over the last five years

This section reviews the change in demand, generator availability and capacity margins, inter-regional trade and prices in the regions of the NEM with a particular focus on Victoria. The charts in this section show profound changes from financial year (FY) 2015–16 to 2018–19 in all NEM regions but particularly in Victoria, over this period.

3.1 Wholesale market demand

Histograms of half-hourly operational demand[12] for the mainland NEM regions is shown in Figure 1. In all states, there is a reduction in the number of half-hourly intervals of higher demands and commensurate increase in the number of intervals of lower demand. This is likely to be explained mainly by the rise of embedded (behind the meter) rooftop PV production on the roofs of homes and businesses.

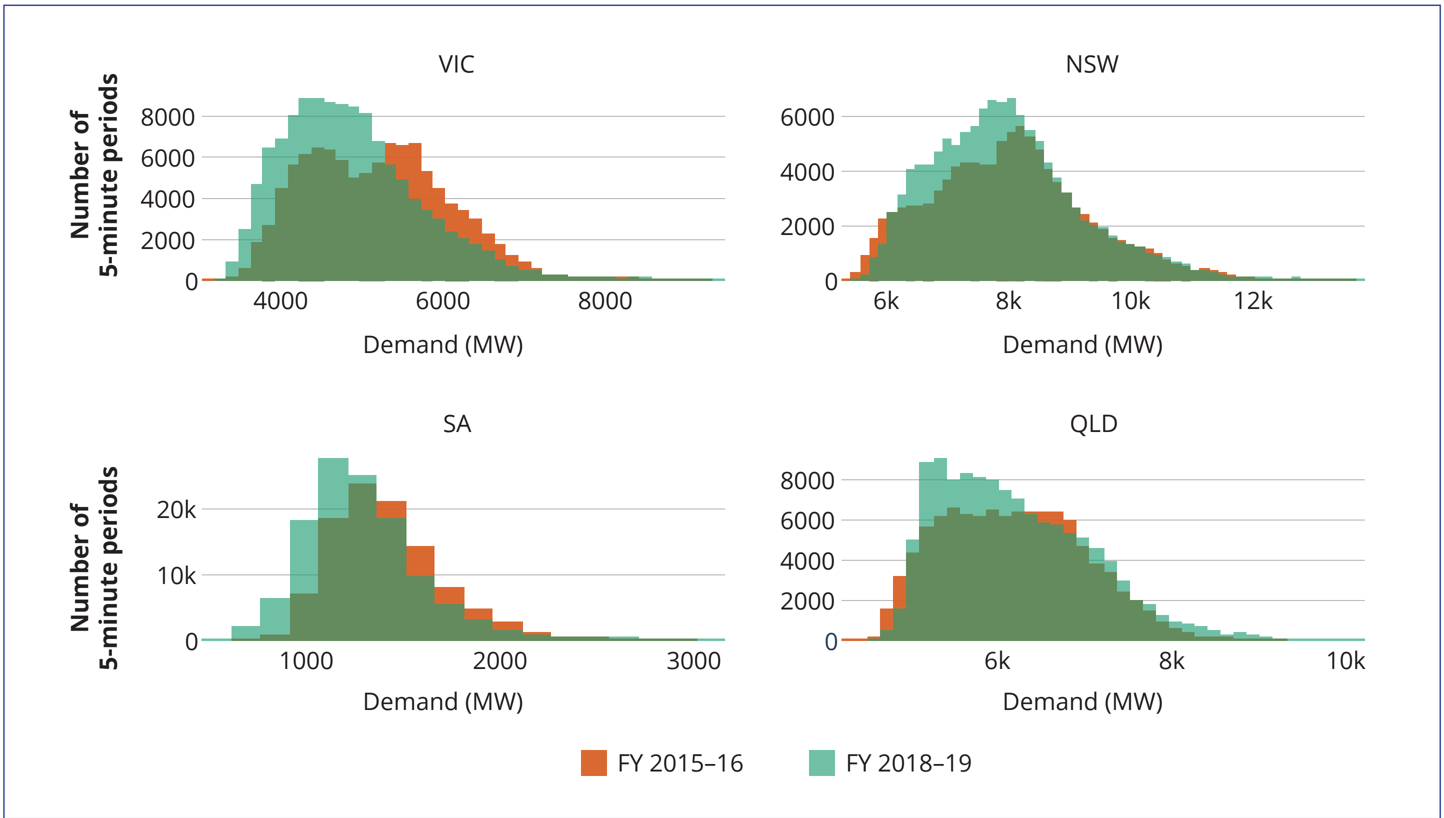

Figure 1 Histogram of half-hourly demand in mainland NEM regions

3.2 Generator availability

Generator availability – as measured by the actual production from variable renewable (wind and solar) capacity and offered capacity from other plant – is a measure of the available supply in the market. The histogram in Figure 2 shows the half-hourly availability in each NEM region in 2015/16 compared to 2018/19. The large reduction in available supply in Victoria is mainly explained by the closure of the Hazelwood Power Station. By comparison there is a large increase in supply in South Australia (explained by much greater renewable generation capacity) and somewhat greater supply in NSW and QLD (also explained by the expansion of renewable generation).

12. Operational demand in a region is demand that is met by scheduled, semi-scheduled or non-scheduled units greater than 30MW. It does not include demand met by behind the meter rooftop PV.

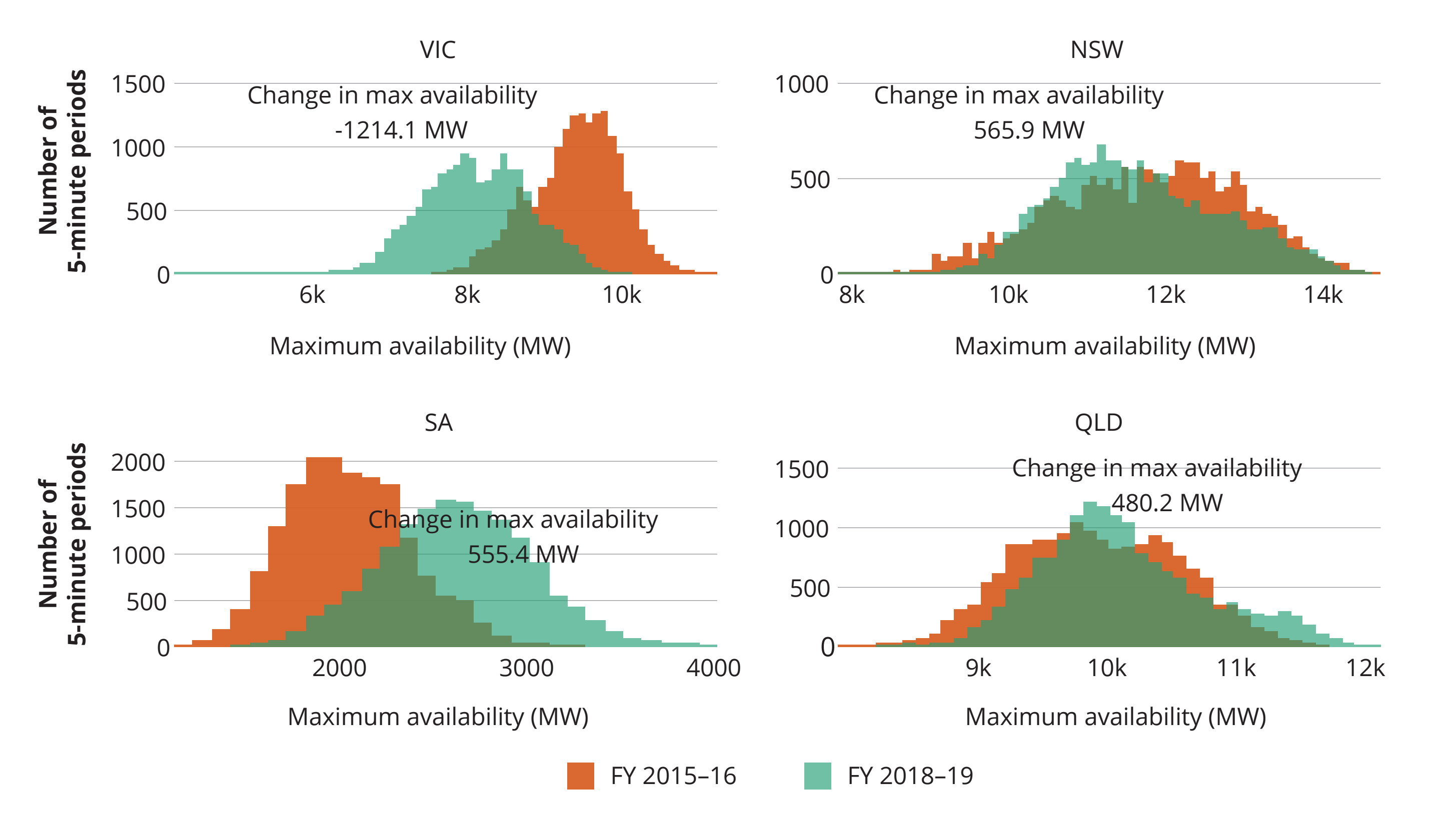

Figure 2 Histogram of half-hourly generation availability in each NEM region in 2015/16 and 2018/19

3.3 Capacity margin

The capacity margin (the difference between the maximum available generation bids into the market less operational demand) provides a measure of the balance between demand and supply. Figure 3 shows the capacity margin in each mainland NEM region. The capacity margin in Victoria has declined significantly following the closure of the Hazelwood Power Station. By comparison, capacity margins increased greatly in SA in response to higher renewable supply and lower operational demand. To a slightly lesser extent, the same trend is visible in QLD.

Figure 4 provides additional insight into the changing capacity margin in Victoria by charting the capacity margin expressed as a percentage of the maximum available capacity over time. This percentage measures the amount of spare capacity that is potentially available to the market. The black line shows the 50% probability of exceedance capacity margin (i.e., the capacity margin that is likely to be exceeded half the time in any one month). The red line shows the actual minimum capacity margin percentage in each month. This shows most clearly the impact of the Hazelwood closure and the event in January 2019 when available supply was less than demand and load had to be shed to bring demand and supply back into balance.

Finally, Figure 5 shows the annual equivalent outage rates of Victoria's three brown coal generators (and Hazelwood up to its closure). The outage rate measures the percentage of the time over a year that the generator is not available. A trend of consistently high outage rates at Yallourn W and Loy Yang A is clear in this chart, and in the year to date Loy Yang B has not joined these stations in demonstrating poor availability. The outage rates are despite extremely high spot prices (described later) which provide very strong incentives for production.

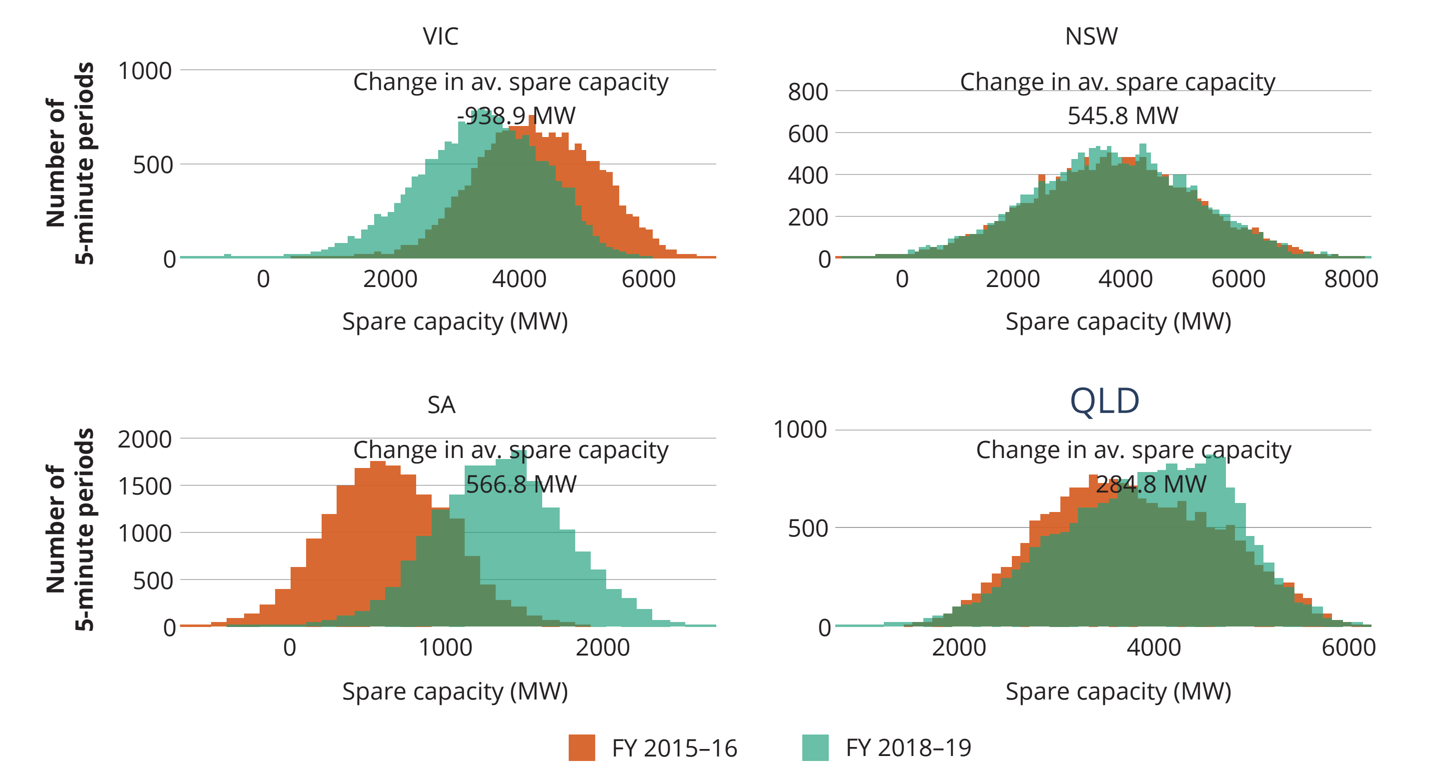

Figure 3 Spare capacity for mainland NEM regions (data source: AEMO, NEMWeb)

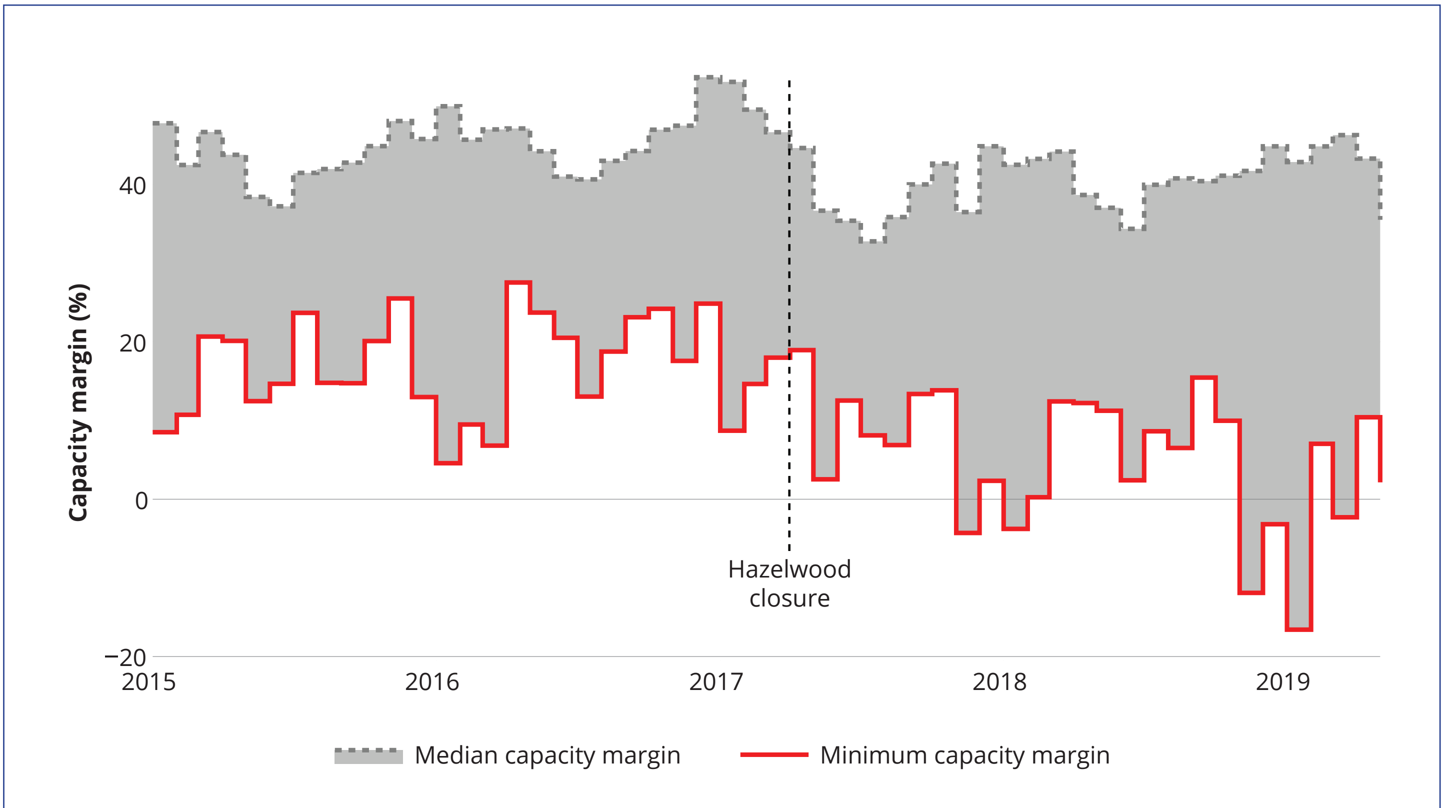

Figure 4 Monthly capacity margin percentage in Victoria (data source: AEMO, NEMWeb)

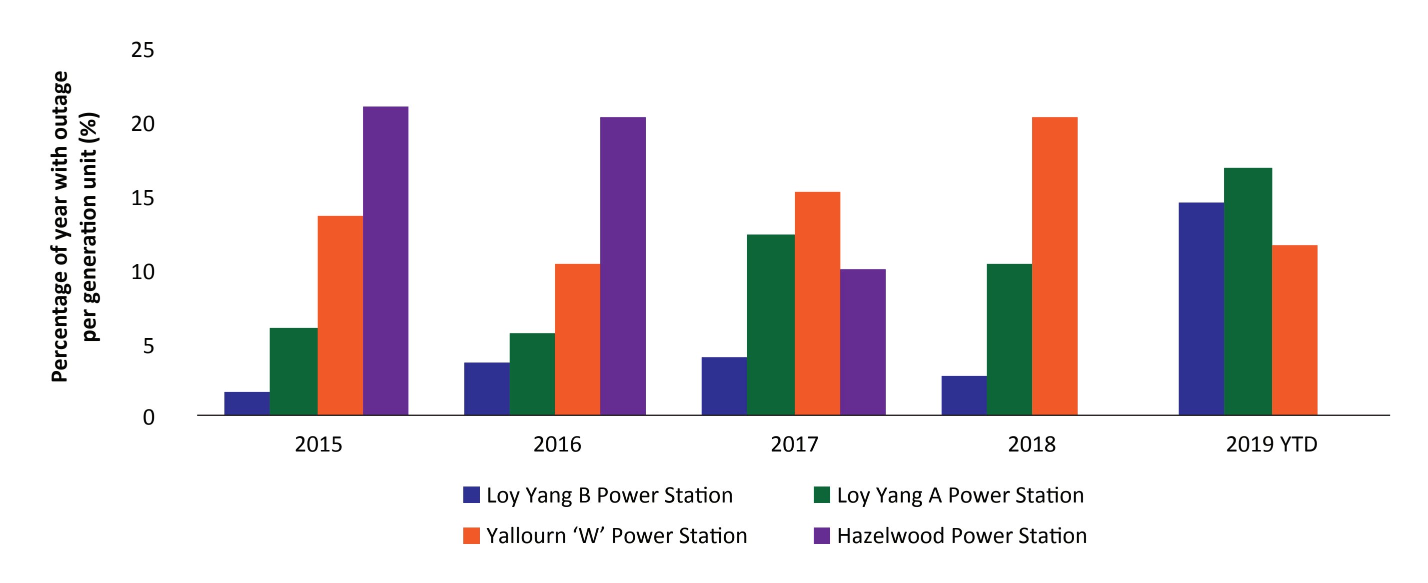

Figure 5 Average annual brown coal generator outage rates (data source: AEMO, NEMWeb)

3.4 Inter-regional trade

The large changes in demand and supply discussed in the previous sub-sections have resulted in large changes in regional power flows, as shown in the histogram in Figure 6. Victoria has shifted from being a significant exporter to having, roughly, a net balance of imports and exports. The opposite is visible in SA. NSW exported and imported more in 2018/19 than 2015/16 while QLD decreased imports and significantly increased exports.

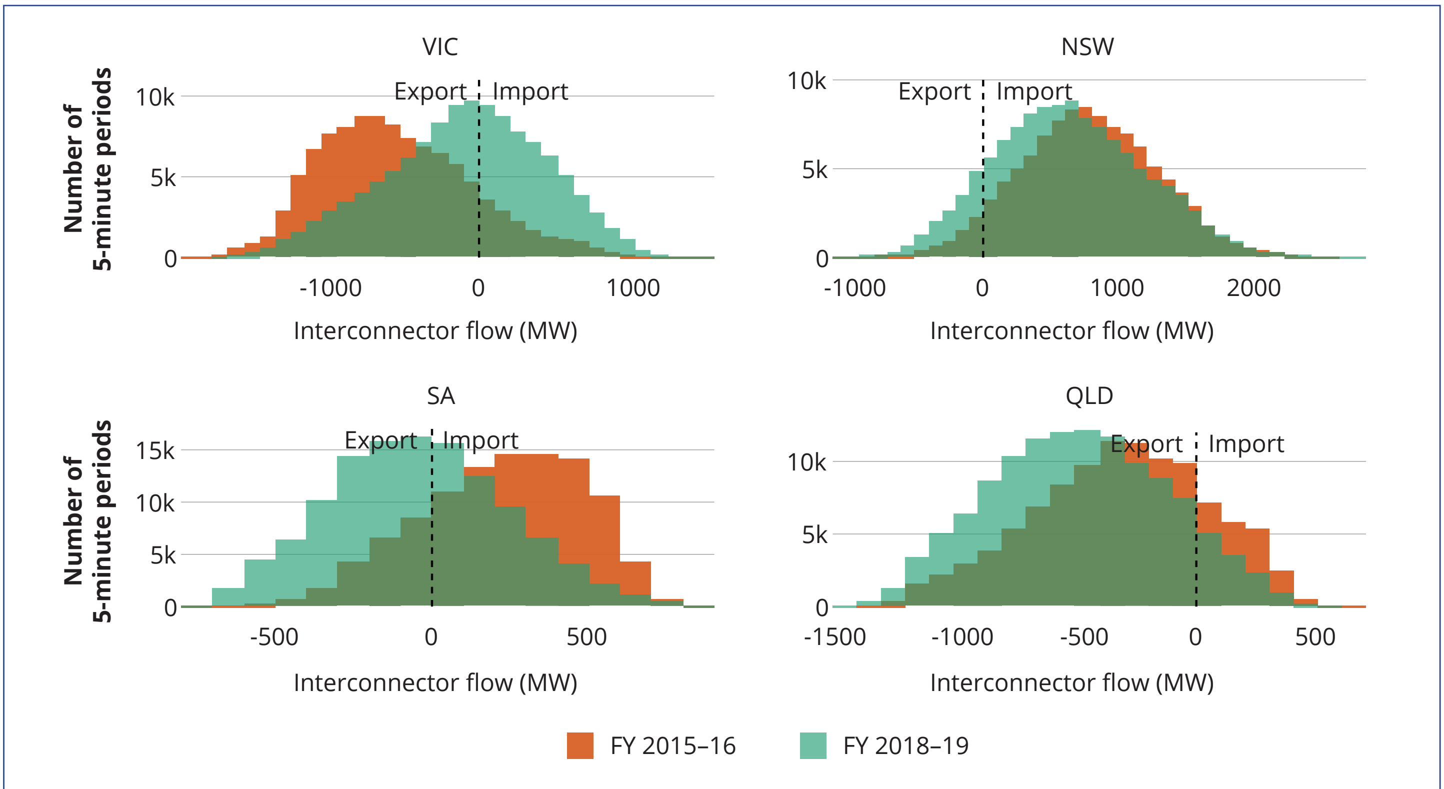

Figure 6 Histograms of half-hourly regional interconnector power flows in 2015/16 and 2018/19 (data source: AEMO, NEMWeb)

Figure 7 narrows the focus to Victoria to show the net cumulative interconnector flows over Victoria's interconnectors to NSW, SA and TAS. In the two financial years before Hazelwood closed[13], the data shows consistent net exports in total of around 4 TWh. In the two financial years since, the data shows aggregate annual interconnector flows that roughly balance demand and supply.

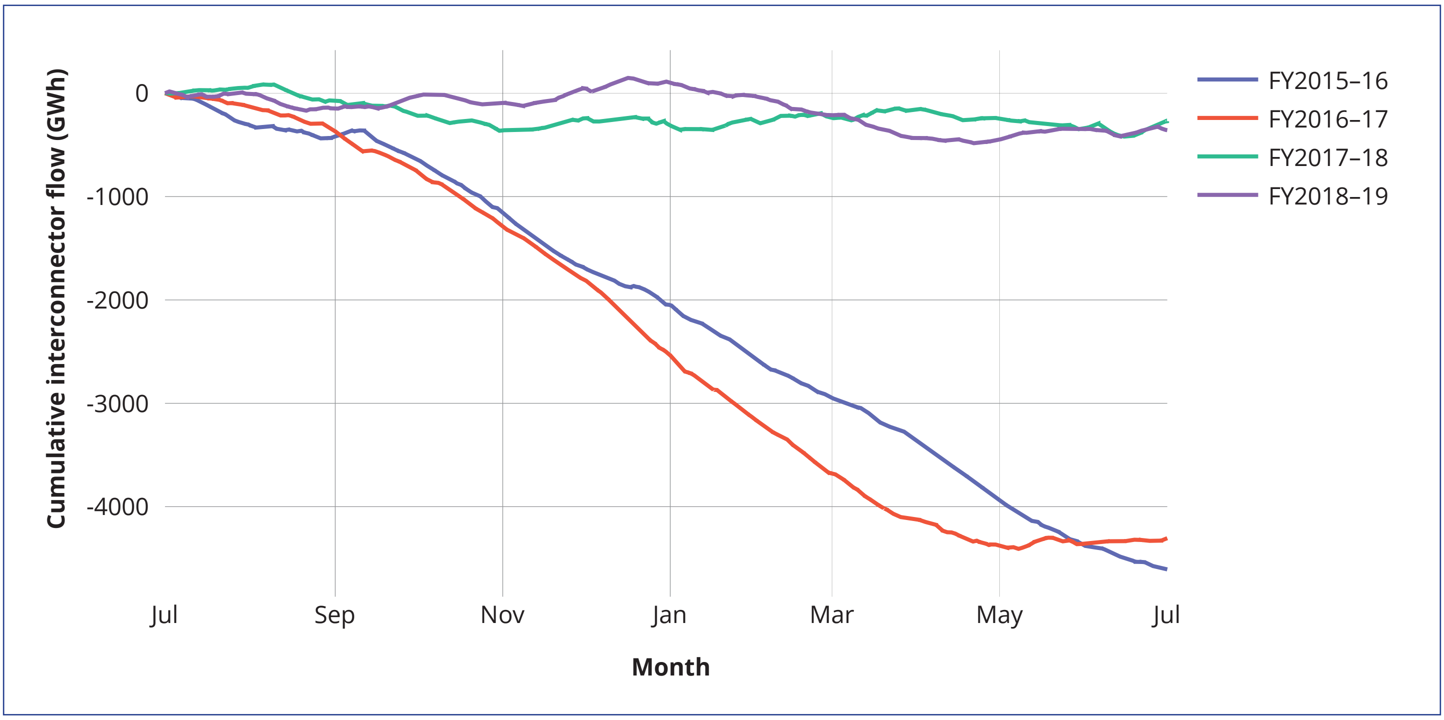

Figure 7 Victoria net cumulative interconnector flow, a negative value indicates export from Victoria (data source: AEMO NEMWeb)

13. To be strictly correct, the 2016/17 financial year has three months (from 1 April) after Hazelwood closed. This is shown in the flat-lining of the red line in the chart from this date.

3.5 Wholesale market gas prices

Gas prices have a significant impact on the wholesale electricity price since they place an upper bound on the prices of fossil fuel production and hence impact not only when gas is used to produce electricity but also when coal is generating. The histogram of hourly gas prices in each NEM region in Figure 8 shows the large step change increase (roughly doubling) in gas prices between 2015/16 and 2018/19.

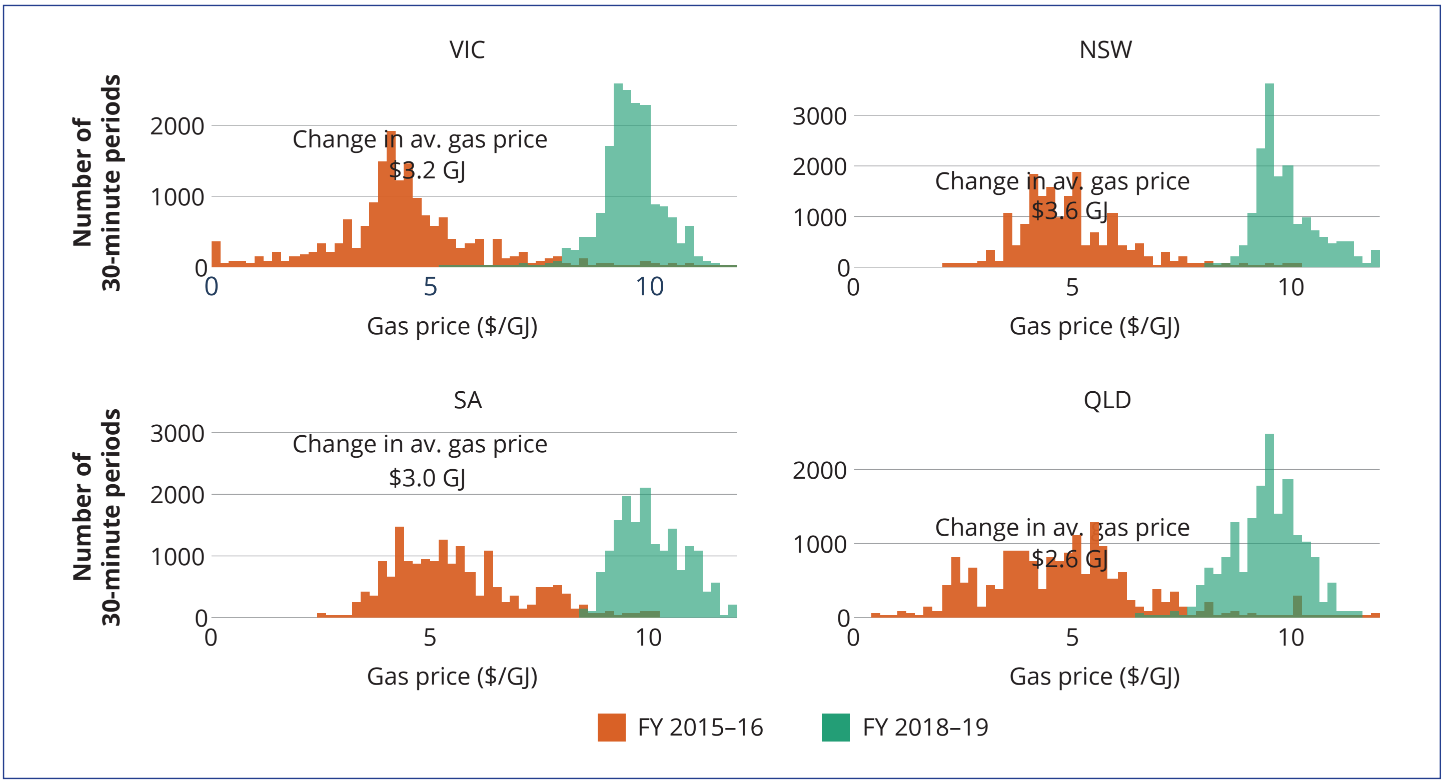

Figure 8 Histogram of hourly wholesale gas prices in 2015/16 and 2018/19 (data source: AEMO NEMWeb)

3.6 Wholesale market electricity prices

Annual volume weighted average electricity prices more than doubled in all mainland NEM regions over the four years from 2014 to 2018, as shown in Figure 9.

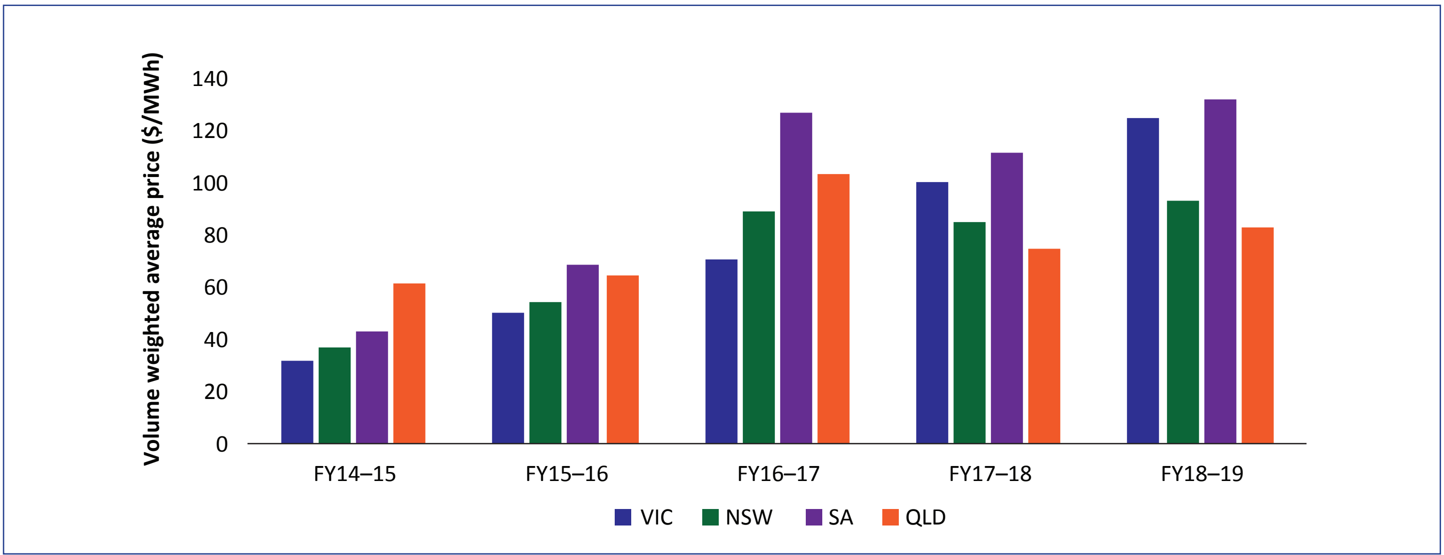

Figure 9 Volume weighted annual average prices by NEM region (data source: AEMO, NEMWeb)

Histograms of the half-hourly spot market prices in Figure 10 show an extraordinary shift in the spread of prices. It can be seen that 2015/16, prices were most frequently around $36/MWh for all NEM regions. In 2018/19 prices were most frequently between $50/MWh and $120/MWh. This is most influenced by Hazelwood leaving the market and the increase in gas price.

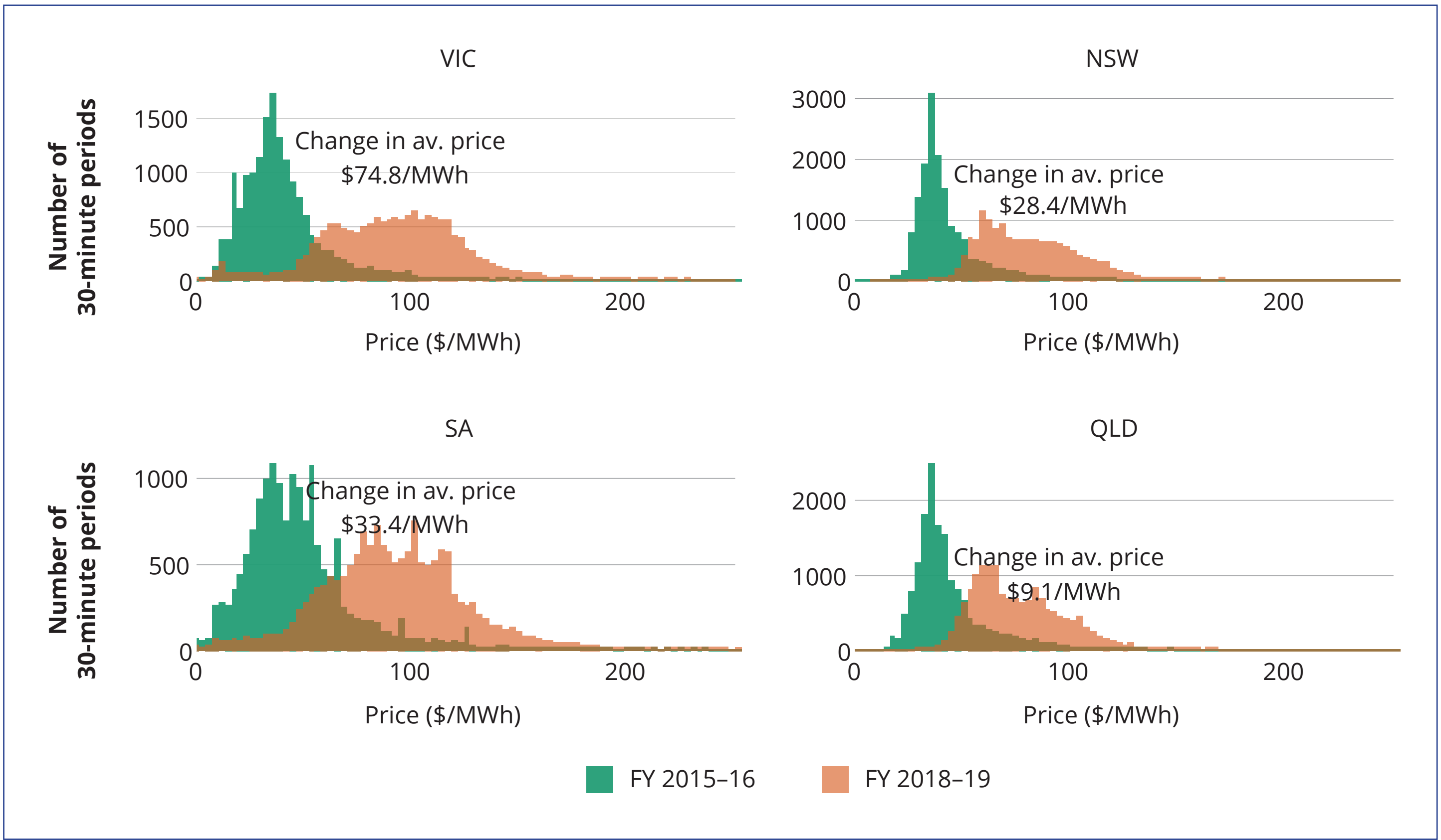

Figure 10 Histogram of half-hourly spot prices in 2015/16 and 2018/19 (data source: AEMO, NEMWeb)

4 Recent and near-future generation expansion and closure

4.1 Generation expansion

The Clean Energy Council's renewable generator register (Clean Energy Council, no date) shows that there are currently 80 wind and solar projects under construction in the NEM. In total, these will add 14GW of capacity. The breakdown of this capacity, as well as the wind and solar capacity operational at July 2019, is shown in Figure 11. Most notable in this chart is the additional wind generation in Victoria and the additional solar generation in SA and QLD.

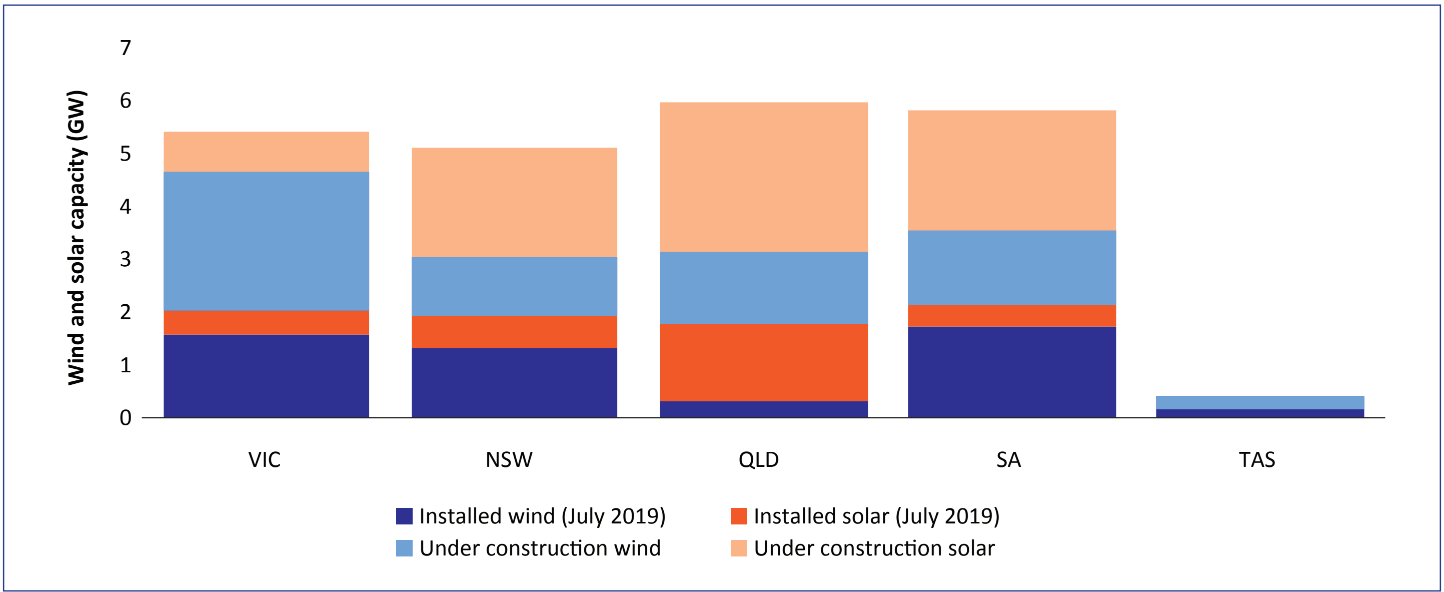

Figure 11 Installed and under-construction wind and solar capacity (data source: Clean Energy Council, no date, and Australian Energy Market Operator, 2019)

Figure 12 shows the projected trajectory of wind and solar additions in the period from July 2019 to July 2022. While Victoria has significant renewable development of this period, per capita or per unit of electricity consumed, renewable capacity is projected to be significantly higher in SA and higher in QLD by the end of this period.

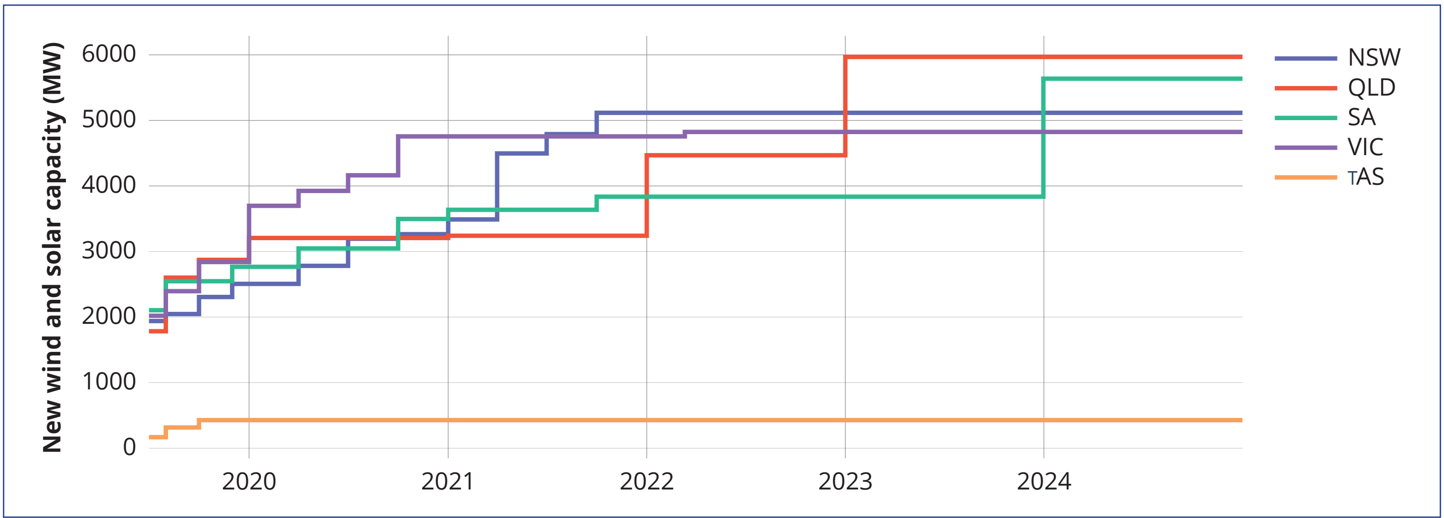

Figure 12 New wind and solar commissioning trajectory. Source: https://www.cleanenergycouncil.org.au/resources/project-tracker[14]

14. The project completion dates came from the renewable project websites and were collected for all 'under construction' projects contained in the Clean Energy Council renewable project tracker. For projects that have no published completion date, it was estimated by adding two years to the project start date.

Figure 13 shows that vast bulk of new wind and solar capacity is not being developed by the NEM's large incumbent generators (AGL Energy, EnergyAustralia and Origin Energy). Depending on eventual ownership and control, this new renewable capacity has the potential to significantly reduce supply-side concentration and stimulate the competitiveness of the market.

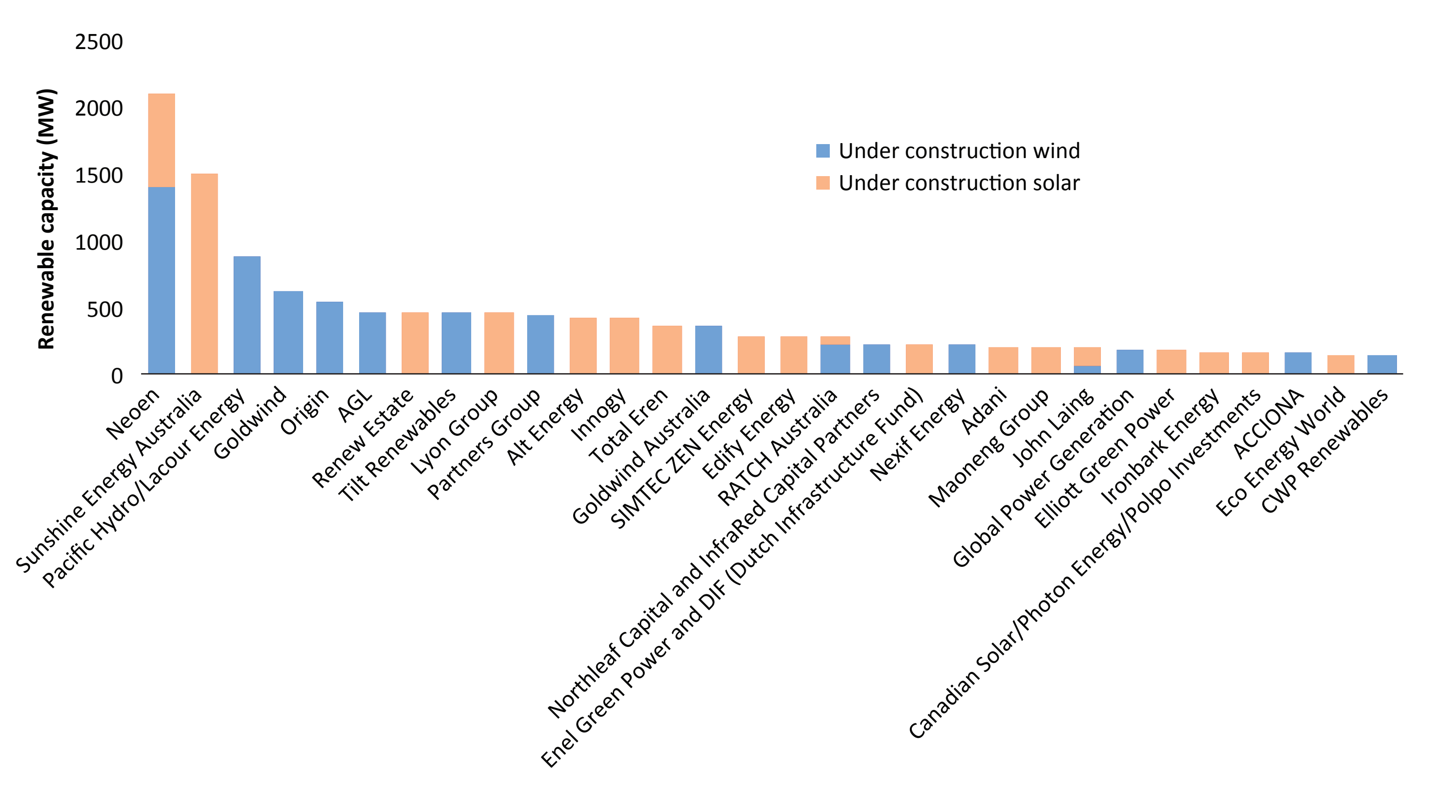

Figure 13 Renewable capacity under construction ranked by developer (data source: Clean Energy Council, no date)

4.2 Generation closure

Figure 14 shows the projected closure schedule of gas and coal generators in AEMO's Integrated System Plan (ISP). Between now and 2035, 13GW of capacity will close, of which 2GW is in Victoria and 8.8GW in NSW, 1.7GW in QLD and 0.5GW in SA.

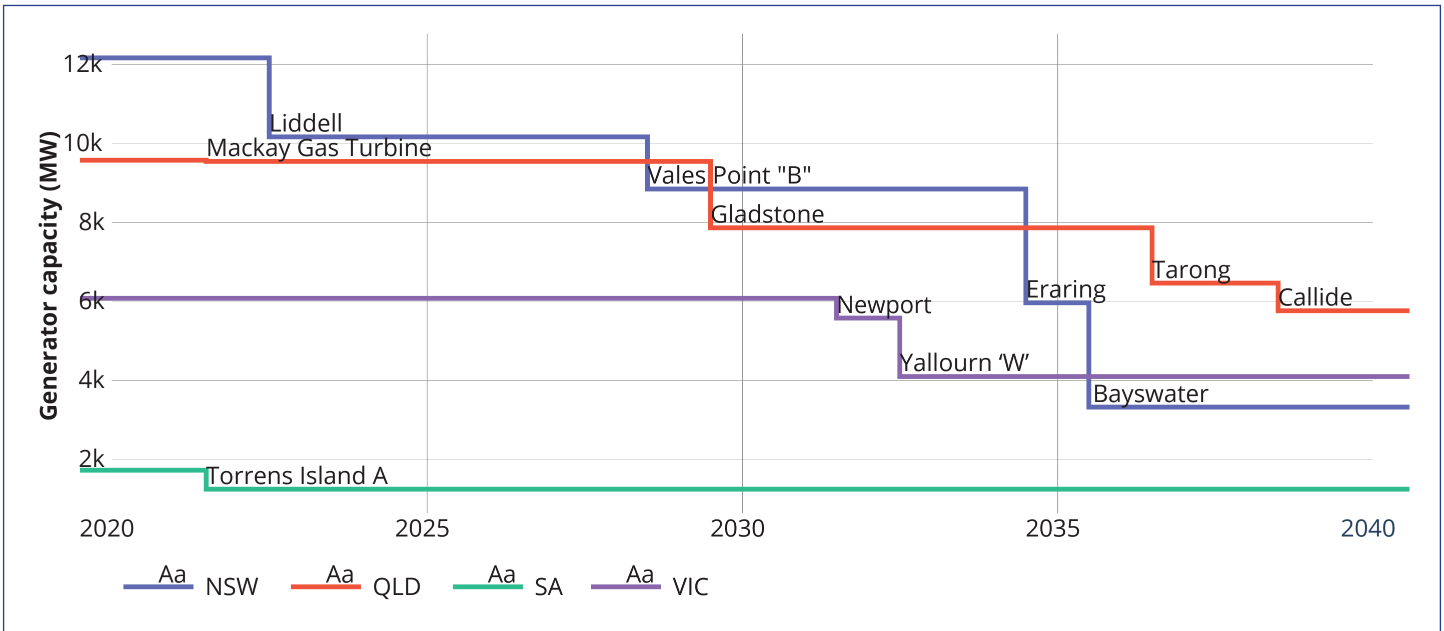

Figure 14 Projected closure trajectory for coal and gas generation (data source: 2019 AEMO ISP Input assumtions)

5 Supply and demand projections to 2028

To develop analytical insights into the energy transition in the NEM, VEPC developed the National Energy Market, Capacity Expansion and Energy Dispatch (NEM-CEED) model. This is a linear optimisation model of the NEM that builds on the AEMO Integrated System Plan (ISP) (AEMO, 2019a) and the Electricity Statement of Opportunities (AEMO, 2018a) and the model in (Xenophon and Hill, 2018) to simulate capacity expansion and energy dispatch optimisation. The model has allowed us to simulate the impact of coal generation closure, renewable generation entry and demand side changes. The Appendix provides a detailed specification of the model.

The focus of our analysis is to understand how the supply side of Victoria's wholesale market is likely to develop over the coming decade. Significant developments that we seek to understand include:

1. The impact of the Victorian Government's legislated 50% renewable electricity by 2030 policy
2. The impact of a more rapid expansion of renewable generation than contemplated in the Government's policy
3. The possible impact of Portland's Alcoa aluminium smelter closure
4. The impact of possible policy to protect black coal generators in NSW or QLD, and
5. The impact of a more rapid expansion of renewable generation than contemplated in the Victorian Government's policy.

The focus of our study is the likely production from coal and renewable sources, and the level of exports.

The base case in our modelling uses AEMO's base case predictions of demand and distributed generation, their assumptions on generation closure (which are based on the information provided by the owners of the generators) and renewable generator entry, and AEMO's characterisation of the transmission network and the technical parameters affecting fossil fuel generation (including the rate at which generators can increase or production and the minimum production levels they are required to operate at). All simulations assume completion of the three high priority transmission upgrades on page 9 of the 2018 ISP.

The Appendix A to this report provides a detailed description of NEM-CEED including all relevant equations and data sources. The appendix also includes back casting results for 2018 to demonstrate the model's ability to correctly predict market outcomes based on the input assumption.

We consider that our model provides plausible estimates of the likely outcomes assuming that AEMO's demand forecasts and capacity expansion assumptions are realistic, that AEMO's characterisation of the power system is realistic and that its estimates of variable production costs and generation entry are reasonable. We have no reason to doubt any of these.

The next sub-section presents the main results and the final sub-section draws out the main implications of those results.

5.1 Results

Figure 15 shows actual outcomes in 2018 and projections for 2023, 2025 and 2028 of net electricity exports from Victoria, generation by grid-scale renewables in Victoria, the production from Victoria's brown coal generators and the residual demand in Victoria (i.e., the operational demand less the variable renewable production in Victoria).

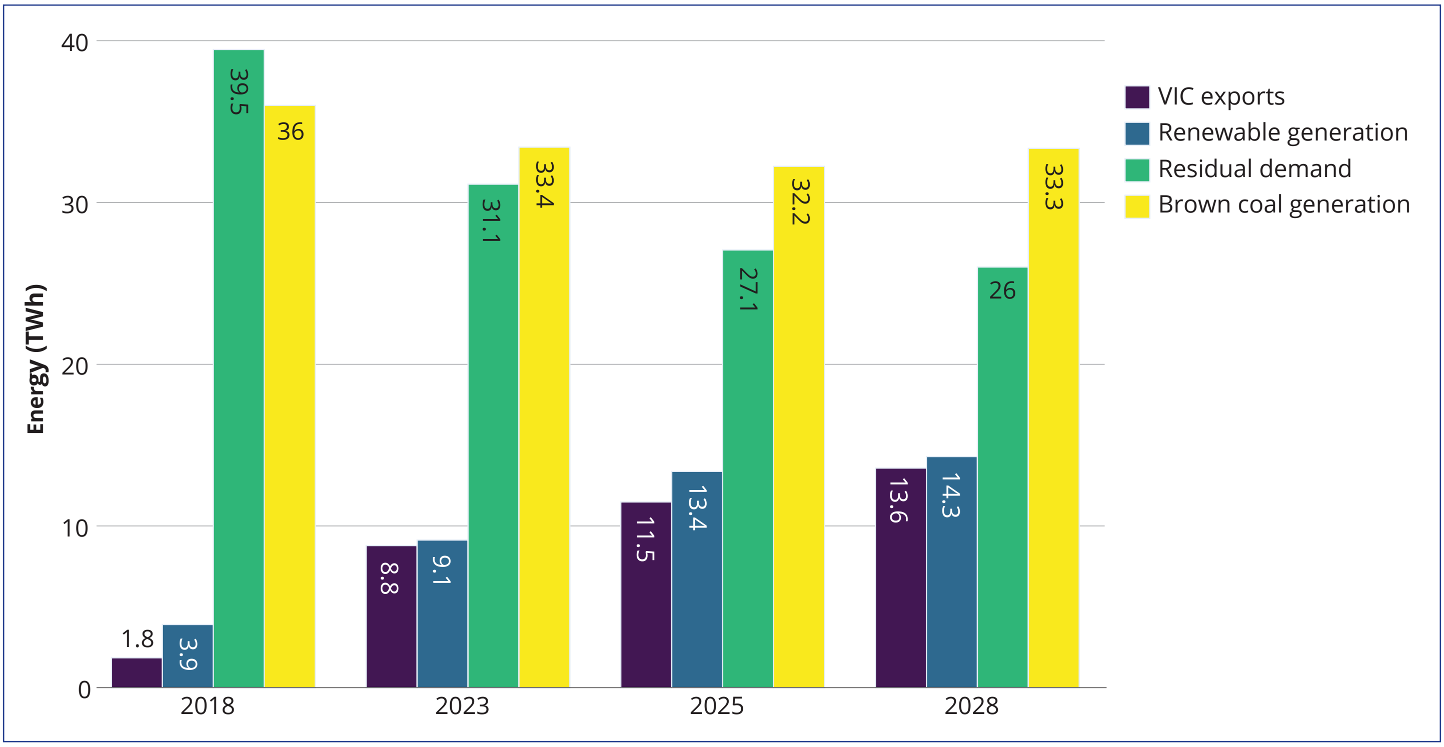

Figure 15 Victorian wholesale demand, production and exports from 2018 to 2028

In 2018, Victoria's brown coal generators produced about ten times as much electricity as Victoria's renewables, and net exports were small (1.8 TWh). By 2028, using the central case assumptions and the Governments' 50% by 2030 renewable electricity target, we project that renewable generation will have expanded roughly four-fold compared to 2018 to be around 40% of Victoria's expected brown coal generation. Residual demand will have declined in response to lower demand and much higher renewable production. Most notably in this chart, the rise of renewable production in Victoria does not significantly impact brown coal production. The underlying dynamic here is that renewable generation in Victoria displaces brown coal production but brown coal production in turn displaces black coal production in NSW and QLD and the transmission system is found to be able to accommodate that dynamic through exports that rise roughly eight-fold over the decade to 2028.

The results in Figure 15 reflect AEMO's central case demand estimates and 2018 ISP capacity expansion levels. Figure 16 presents the results of our study of the impact of different assumptions and measured by the consequent production by coal generators in the NEM in 2028. These different scenario assumptions include:

1. **Scenario 1:** No new large-scale renewable entry in the NEM after the current crop of renewable generators under development are commissioned.
2. **Scenario 2:** The Victorian Government's currently legislated 50% RE by 2030 target
3. **Scenario 3:** Alcoa closed and the Victorian Government's currently legislated 50% RE by 2030 target
4. **Scenario 4:** Twice as much renewable generation entry in Victoria between 2023 and 2030 than is assumed will occur to meet the Government's current 50% by 2030 policy.
5. **Scenario 5:** subsidising black coal generation in NSW and QLD to be cheaper than brown coal.

Figure 16 shows that brown coal production is expected to decline by about 10% in 2023 relative to 2018 levels after the renewable electricity projects in the NEM that are currently under construction are commissioned. However brown coal production by 2028 is barely changed from the 2023 level as renewable production expands to meet the Government's 2030 policy, and similarly changes little if no new renewable generation is built after 2023 (Scenario 1), or the Government's renewables target is met (Scenario 2) or double the amount is built than is expected to meet the Government's legislated policy (Scenario 3). This shows that increased exports are able to offset the displacement from new renewable capacity in the decade to 2028.

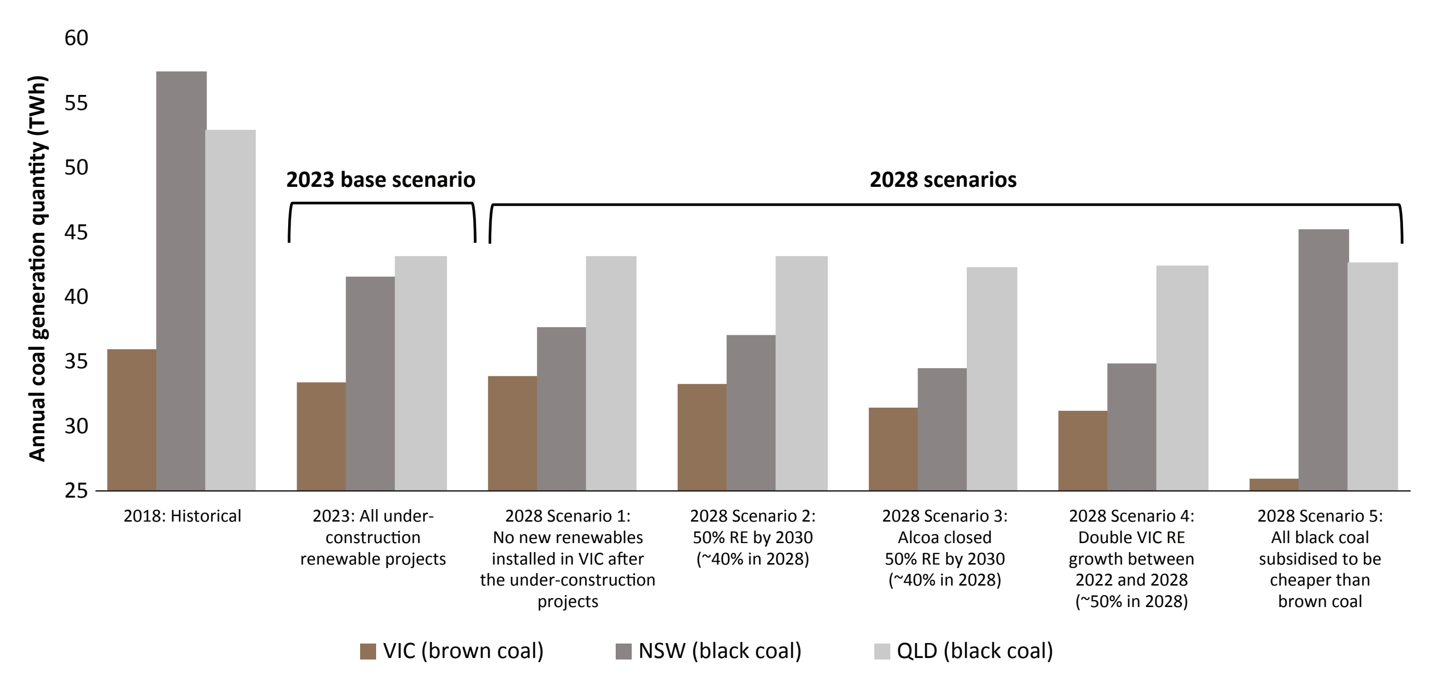

Figure 16 Annual brown coal generation under different assumptions

Alcoa's closure does have an influence on brown coal generation but it is not large (Scenario 4). However our modelling does find that brown coal production is very sensitive to policy to protect black coal generation (Scenario 5).

The (Commonwealth) Minister of Energy has said he intends that existing coal generators should be running "flat out". It is not obvious precisely what is meant by this so we have modelled this as a subsidy that effectively reduces black coal production costs to be just under brown coal costs. This results in black coal generators running as 'flat out' as possible. Brown coal generation reduces significantly in this case since aggregate demand is unchanged and brown coal cannot compete successfully against renewable generation which has no avoidable production cost.[15] We could alternatively have modelled the Minister's policy as sustaining black coal generation in 2028 at the level of 2018. While this might be what he intended, this would be a radical outcome that would almost certainly lead to the closure of two of the three Victoria brown coal generators or alternatively would require that all of the 9,000 MW of renewable generation likely to be commissioned between now and 2023 will be forced to idle.

The aggregate annual production from brown coal in Scenario 5 is just 5 TWh greater than the level that would occur if all brown coal was producing at its minimum stable generation level for the whole year. Effectively under the black coal protection scenario, brown coal generators will only produce above their minimum stable generation levels (the model does not allow closure) when transmission constraints bind import limits to Victoria and brown coal is then needed to meet evening peak demands when aggregate production from renewable generation is not adequate. This result is shown in Figure 17 for summer weekdays which shows narrow 10%/90% probability of exceedance bands for the production of all three generators close to each of their minimum stable generating levels for almost the whole day except for a (mostly) mild increase at the time of the evening peak demands. This mode of operation is commercially unsustainable for brown coal generators. Protecting black coal generation even to the level that still means substantially lower production by 2028 compared to 2018 is likely nonetheless to lead to the closure of at least one brown coal generating unit.

15. The model forces aggregate brown coal production from all three plants down to a level just above minimum stable generation, needed to meet demand in Victoria.

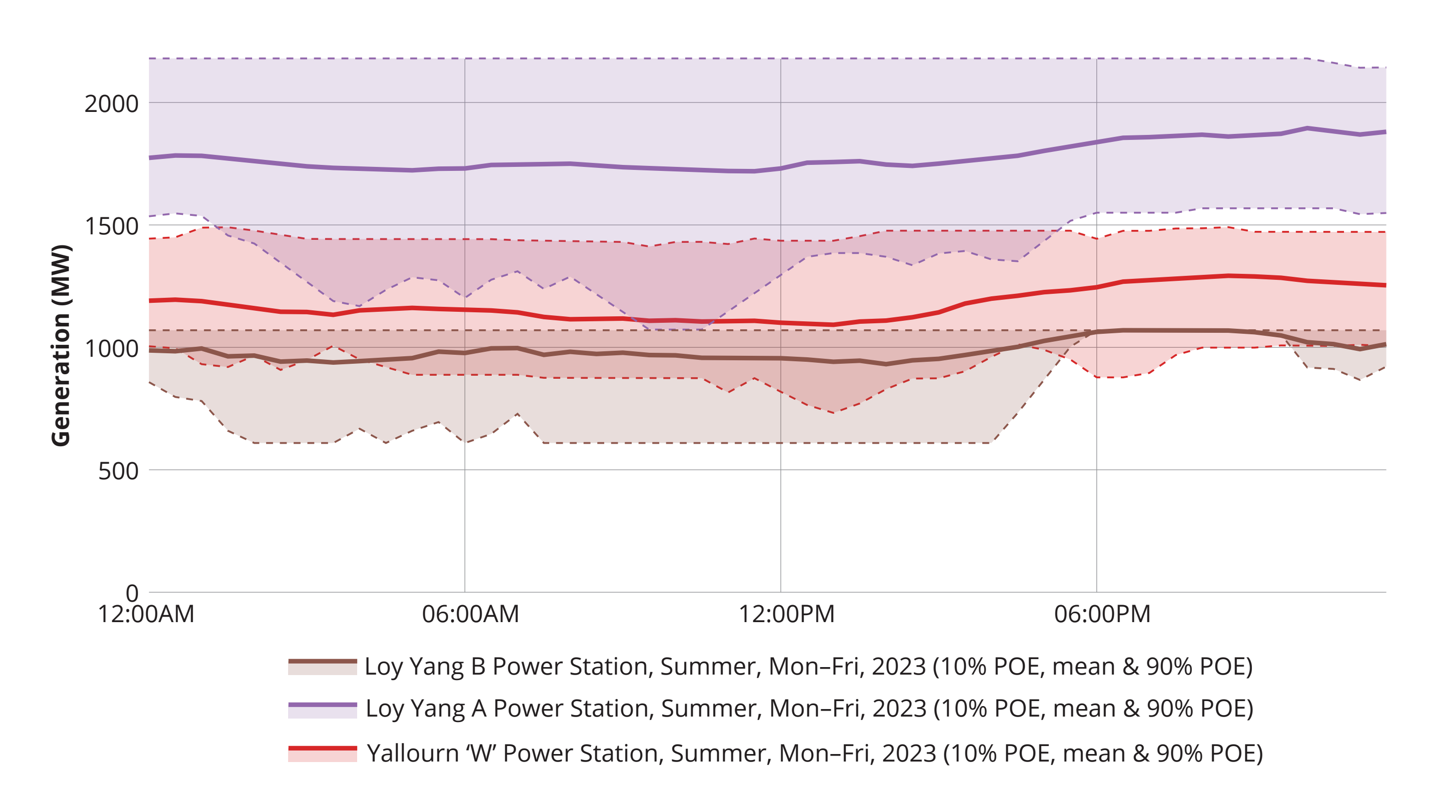

Figure 17 Brown coal generator daily average production under "protect black coal" assumptions for summer weekdays

To understand further an important dynamic revealed in Figure 17, Figure 18 shows the operational demand and residual demand for 2018 (actual) and the forecasts for 2023 and 2028 under the ISP base case assumptions. The operational demand is the simultaneous demand on the transmission system while the residual demand is the operational demand less the production from the large-scale renewables (i.e. the demand left for fossil fuel generators and non-variable renewables). The figure shows that the load shape remains largely unchanged despite the large expansion of renewable production. This reflects the expectation that a large amount of the renewable production will be wind rather than solar.

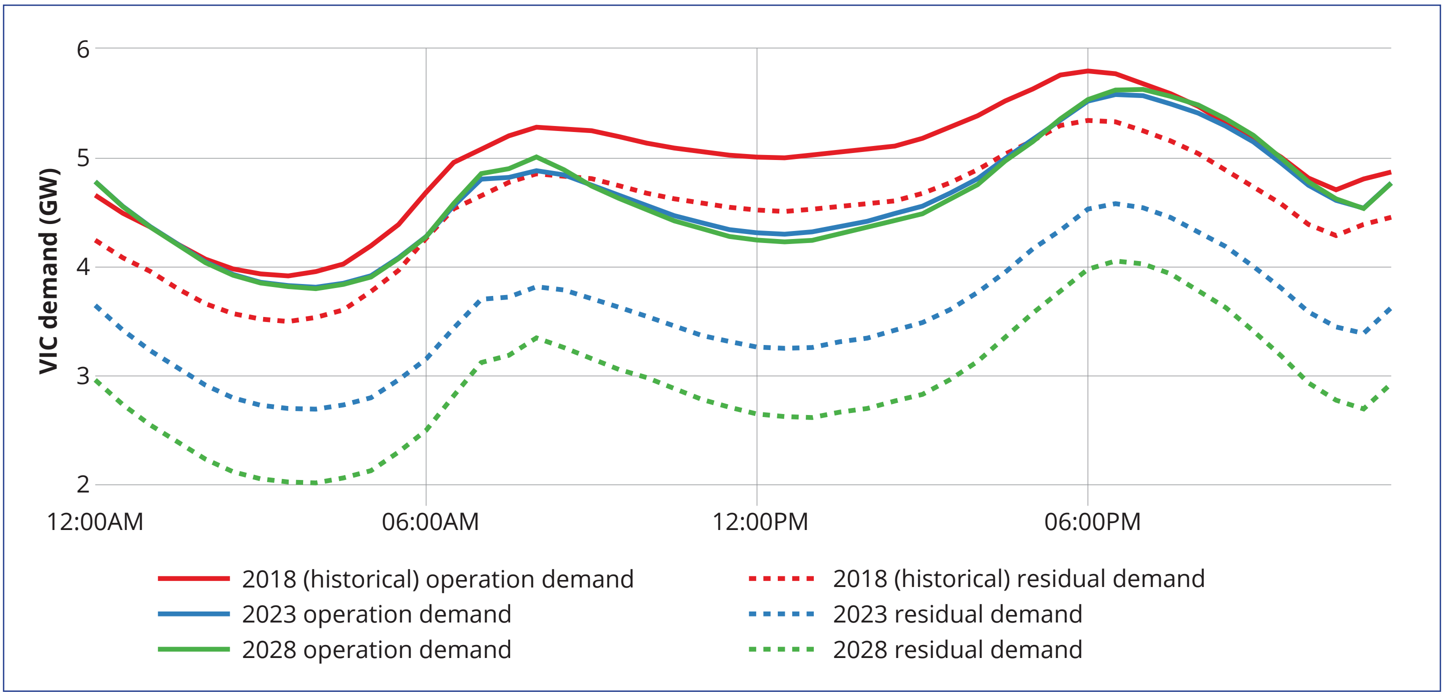

Figure 18 Average operational and residual demand in Victoria in 2018, 2023 and 2028

By comparison, for interest we show in Figure 19 the same batch of curves for Queensland. This shows the familiar "duck curve" associated with the forecast of a proportionately far greater expansion of solar generation expansion in Queensland relative to Victoria.

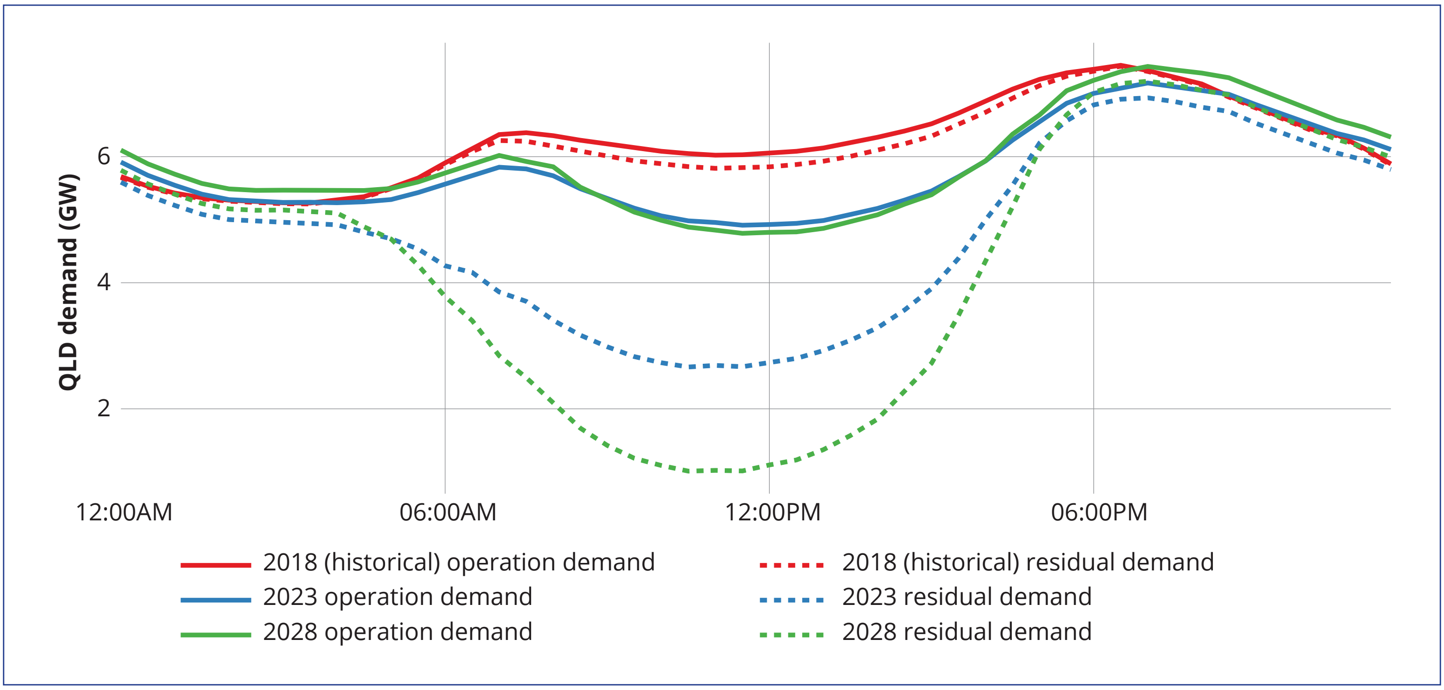

Figure 19 Average operational and residual demand in Queensland in 2018, 2023 and 2028

Finally we present four charts – Figure 20 to Figure 23 – that provide additional insight into the main results of our analysis. Figure 20 and Figure 21 present the percentage of the year that our model predicts coal generators will be dispatched at the "minimum stable generation" levels. Figure 22 and Figure 23 show the percentage changes in annual production relative to 2018, that our model predicts.

These results should not be taken as predictions of the actual dispatch of any particular plant since this will vary for reasons we are not able to capture here (their actual avoidable costs may be different to AEMO's estimate of their marginal costs; demand is likely to be different, generators may bid strategically and so on). However the essential picture is clear: several black coal generators are likely to be pushed out of the market as a result of the renewable generation under construction and competition from brown coal generators.

In fact the charts support a conclusion of far more rapid black coal generator withdrawal from the market than has been publicly announced: operating coal generators at their minimum stable generation for so much of the year will not only be technically infeasible but commercially unsustainable: dispatch to these levels is consistent with a collapse in wholesale prices. It is likely that coal generation will withdraw from the market – either through closure or station/unit mothballing for this reason.

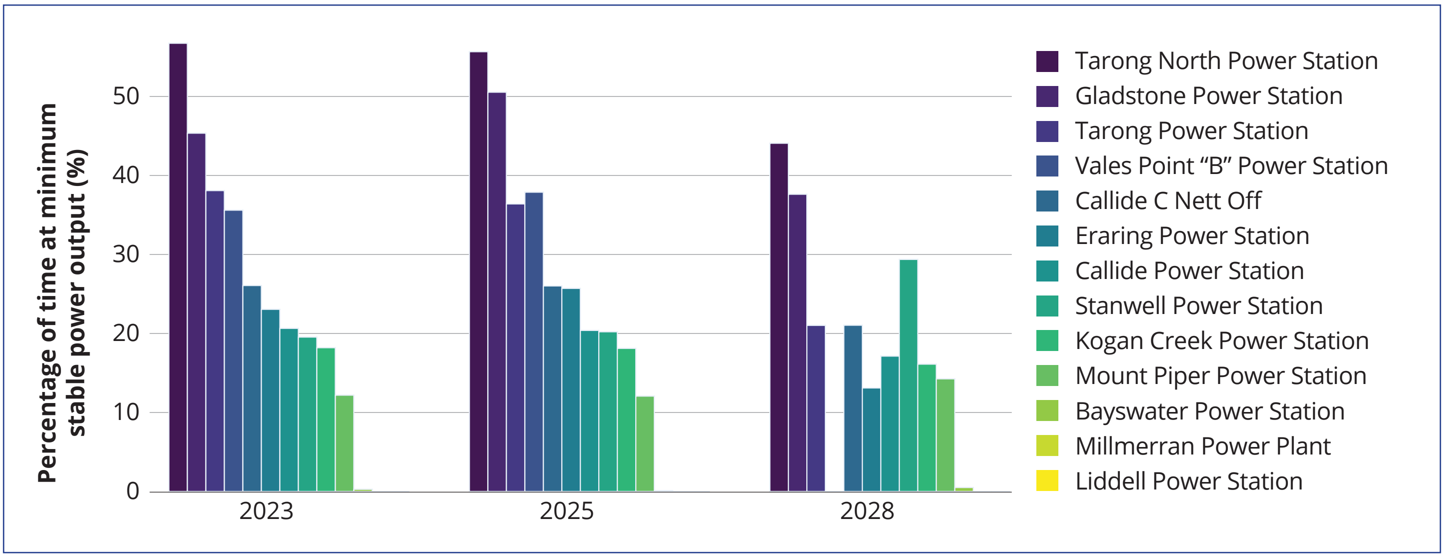

Figure 20 Minimum stable generation: black coal generators

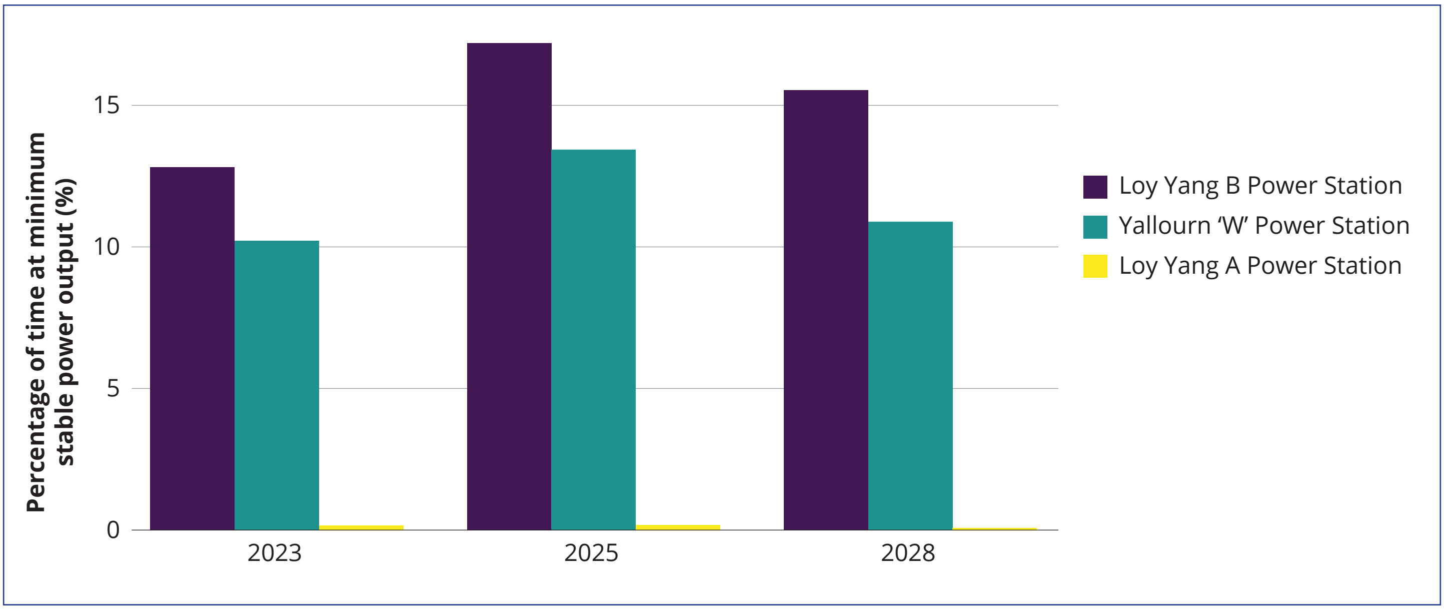

Figure 21 Minimum stable generation: brown coal generators

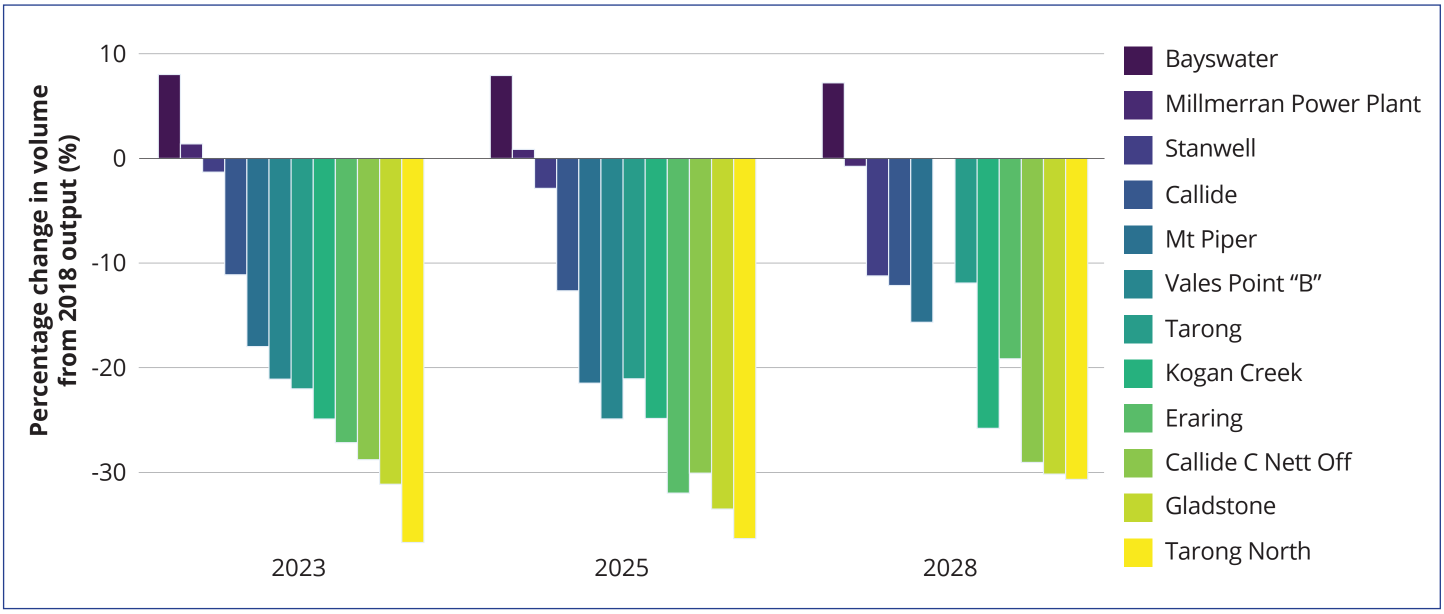

Figure 22 Percentage change in black coal annual output from 2018

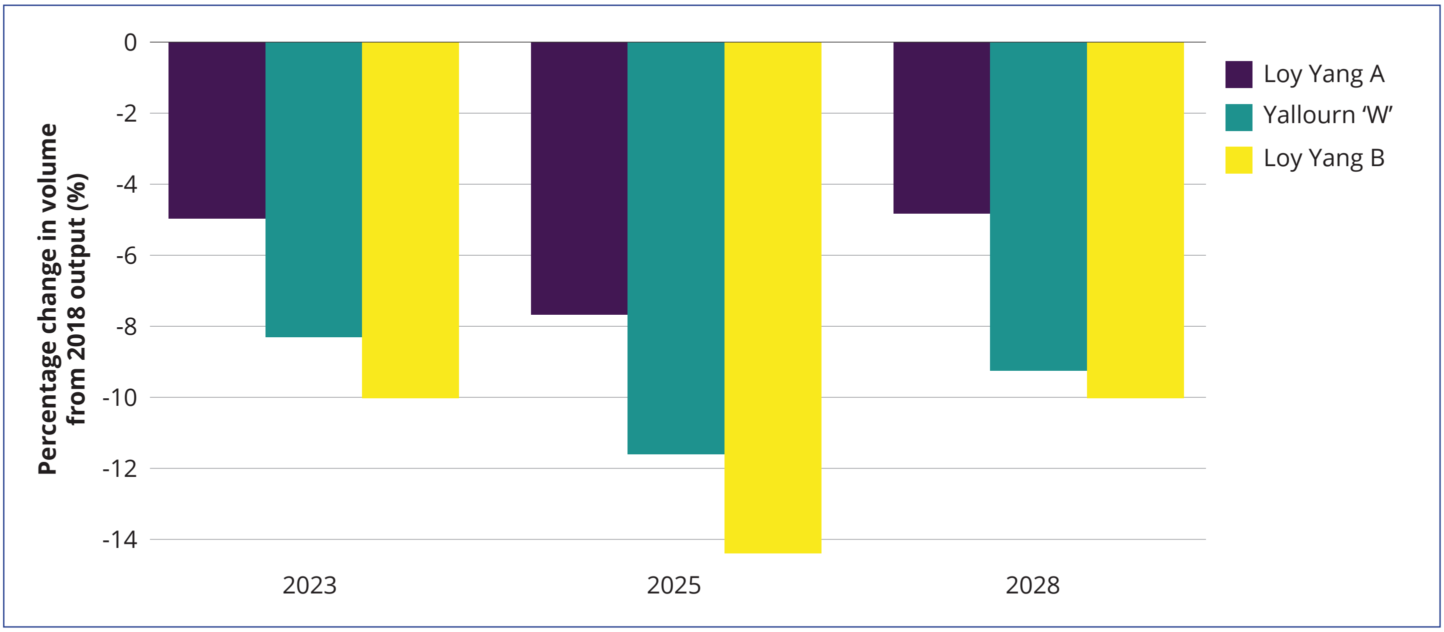

Figure 23 Percentage change in brown coal annual output from 2018

5.2 Discussion

The outcome of the modelling presented in the previous sub-section should not be taken as a prediction of outcomes for any individual generator. While back-casting (see Appendix A) provides confidence that our model correctly represents the actual system, the predictions rely on forecasts of demand, production cost and generation closure. While we do not expect that the results will be sensitive to either production costs or demand, they will be sensitive to generation closure. On this we have used AEMO assumptions which in turn take as given the stated intentions of the generation owners.

Our modelling suggests that the stated coal closure schedules are highly unlikely. Black coal generation will be pushed out of the market through the expansion of renewable generation and increased production from brown coal generators. The (Commonwealth) Energy Minister's desire that coal generators run "flat out" cannot be achieved unless the Minister is willing to curtail renewable generators. If alternatively the objective is to run black coal generators flat out, this will require subsidies so that black coal generators are able to offer their production to the market at a lower price than the brown coal generators. If the Minister pursues this approach, we expect that two of the three brown coal generators will be forced out of the market.

An alternative approach of placing barriers to renewable entry (and spilling the production of renewable generators about to enter service) will entrench incumbent producers at the expense of higher prices, grid defection and less reliable supply. It is implausible that coal generators will respond to protection by investing to sustain capacity in a declining market.

From the perspective of the power system in Victoria, the picture is clear: new entry renewable generation will displace brown coal generation which will in turn displace black coal generation in NSW and QLD. Our modelling concludes that the transmission system will be able to sustain higher exports, conditional on intra-regional expansion in north and central Victoria by 2025. However by 2028 this transmission is likely to be running close to its export capacity limits for much of the time. Brown coal generation volumes in Victoria are insensitive to the rate of renewable production growth, at least until 2028 since export markets are able to provide the demand for the displaced brown coal production.

We also examined the effect of the possible closure of Alcoa's Portland aluminium smelter. Our modelling suggests that closure of this plant will have little impact on brown coal production until transmission export limits bind. At this point the circa 600 MW loss of demand in Victoria will bite into production from brown coal generation and at this point brown coal generation closure will become more likely if Alcoa's closes.

While demand for brown coal generation can be expected to remain robust even with much faster renewable entry than consistent with the Governments 50% by 2030 target, reliable supply in Victoria is still a significant concern taking into account:

- the very poor reliability of all three plants
- their inherent inflexibility (long start times, high minimum stable generation and slow ramp rates)
- the concentration of supply in just three plants with just 10 generation units in total, and
- uncertainty in Commonwealth policy, particularly with respect of the Minister's stated goal of maximising coal generation.

Adequate insurance against unexpected brown coal generation failure will be essential in ensuring reliable supply in Victoria. While it is not the focus of this study, our modelling suggests both NSW and QLD are in a similar if not more challenging situation considering the high likelihood of mothballing or closure much sooner than currently announced.

6 Conclusions

The main conclusions of the two parts of this report are summarised here.

Marketing modelling

1. Our market modelling concludes that the expansion of renewable generation in Victoria will displace brown coal generation, which in turn will displace black coal generation in NSW and QLD. We expect that existing transmission capacity, in addition to intra-regional augmentations in north and central Victoria, will be sufficient to ensure that brown coal production is largely unaffected by the rate of renewable generation expansion in Victoria in the coming decade.
2. Renewable and brown coal generation will increasingly displace black coal generators to the point that several will be operating at their minimum stable generation levels for at least half the year. This is unsustainable and several black coal generators are likely to close sooner than currently announced.
3. A policy to protect coal production will simply bring forward brown coal generator closure. Likewise, clamping down on the rate of renewable expansion will raise prices and accelerate grid defection. It is unlikely incumbents will respond to such protection by investing to prolong their operation in a declining market.
4. If Alcoa's Portland aluminium smelter closed, it would be unlikely to affect brown coal production until export constraints start to bind, which we expect towards the end of the coming decade. From that point, the loss of demand in Victoria will affect the market for brown coal generation and is likely to enhance the prospects of brown coal generator closure.
5. The mix of wind and solar variable renewable generation in Victoria is unlikely to result in the more demanding "duck curve" demand profile that AEMO's demand forecasts predict for Queensland where solar is likely to dominate grid-scale new entry. However, reliable supply in Victoria is likely to be affected particularly by:
    - the supply side concentration of its brown coal fleet (just three stations sharing just 10 production units amongst them);
    - the poor reliability of Victoria's brown coal generators;
    - the prospect of Commonwealth policy to protect black coal generators; and
    - the ever more precarious "social licence to operate" of Victoria's highly polluting coal generators.

Regulatory/market analysis

1. Whether or not the mandatory wholesale spot market with its half-hourly prices and market price cap provides appropriate incentives for reliable investment is, and likely always will be, a contested point. However, there seems to be little doubt that policy makers, regulators and the industry do not think it does. There is no evidence that regulators or policy makers have resisted the reliability recommendations of the Finkel Review or the reliability arm of the NEG on the basis that the market is already working well and providing appropriate incentives for reliable supply.
2. The Retailer Reliability Obligation is unlikely to deliver reliable supply. On the demand side of the scheme, using only a one-in-two-year demand it will provide insufficient investment for retailers to contract additional supply. On the supply side of the scheme, the great majority of contracts created pursuant to the RRO will simply be internal contracts between the generating and retail arms of the same generator-retailer. The RRO provides powerful incentives for the appearance but not the reality of compliance and we doubt the regulator will be able to prevent this.

3. The AEMC's rejection of AEMO's RERT proposals is not well founded. AEMO's arguments for a reliability standard that takes account of the value of outages and not just the volume of outages is convincing. Similarly our market modelling (discussed in greater detail below) supports AEMO's proposals for the provision of strategic reserves contracted over long periods.
4. The AEMC's Cogati proposals are not motivated by evidence of a problem and the AEMC has failed to consider the relative merits of its proposal in comparison to the many alternatives. The proposal lacks a solid foundation in theory, will massively increase transaction costs and asymmetrically benefit incumbent producers relative to new entrants. We cannot find any good reason to pursue this.

In summary, we consider that existing regulatory and market arrangements can not be relied on to deliver reliable supply.

7 Recommendations

On the basis of the analysis and findings of this report we suggest the following for consideration by the Government of Victoria:

1. AEMO should be asked to urgently develop the detail of a reliability standard that it considers to be appropriate for Victoria taking account of the risks to reliable supply in Victoria and the value of supply shortfalls. It may well be that other states would be interested in cooperating with Victoria and AEMO in this. While such co-operation would be value, Victoria should proceed nonetheless if cooperation is not possible.
2. AEMO should be asked to develop the detail of the procurement arrangements to establish strategic reserves needed to ensure reliable supply in Victoria.
3. The Government should consider the administrative arrangements (rule change applications or derogations) needed to implement the reliability standard and strategic reserve arrangements without delay, once they have been developed.
4. Changes to the arrangements for the regulatory approval of intra-regional transmission augmentations – specifically the removal of the Regulatory Investment Test – should be considered in order to ensure that the north and central Victoria augmentations needed to ensure supply by new entry renewable generators in those regions are commissioned in time for those generators to transport their produce to market.
5. Building on an important recommendation of the Finkel Review, future Victorian Government policy support for large renewable generators should require that a proportion of production is firmed through the installation of storage, preferably located behind the meter.
6. The Government should consider accelerating the development of renewable generation in Victoria to improve reliability.
7. The Government should consider a suite of policy changes to strengthen supply/reduce demand during weekdays from 6 to 9pm. This might include changes to network tariffs, the implementation of demand-side response schemes and incentives to orient rooftop solar to the west.

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Appendix A: NEM-CEED model description

This appendix gives an overview of the NEM-CEED (National Energy Market, Capacity Expansion and Energy Dispatch) model applied in Chapter 5 of this report. The NEM-CEED model is a linear program optimisation model that considers the technical constraints of the energy market to dispatch the lowest-cost generation to meet demand, and weigh up the cost of new generation capacity, and technical limitations of new supply, to reduce the cost of energy supply to the market.

To provide the most accurate output, the model uses the most up to date demand, renewable energy zone profiles sourced from the 2019 AEMO and technology cost forecasts provided by AEMO (AEMO, 2018a, 2019a). The model uses a simplified formulation of the NEM, shown in Figure 24, classifying the transmission network into a set of transmission zones to match the AEMO National Transmission Network Development Plan (AEMO, 2018b). The model formulation has been created to be flexible to take into consideration the impact of new policy, the unique characteristics of all generators in the market and the role of new technologies such as storage. A one-year optimisation window allows the sizing of renewable resources and storage while considering the yearly seasonality and the short-term coincidence between demand and geospatial renewable resources. Though the model has the functionality to investigate capacity expansion in the NEM, the analysis in Chapter 5 disables this function and instead uses a list of under construction projects sourced from (Clean Energy Council, no date) and 2018 ISP (neutral scenario) capacity expansion forecasts.

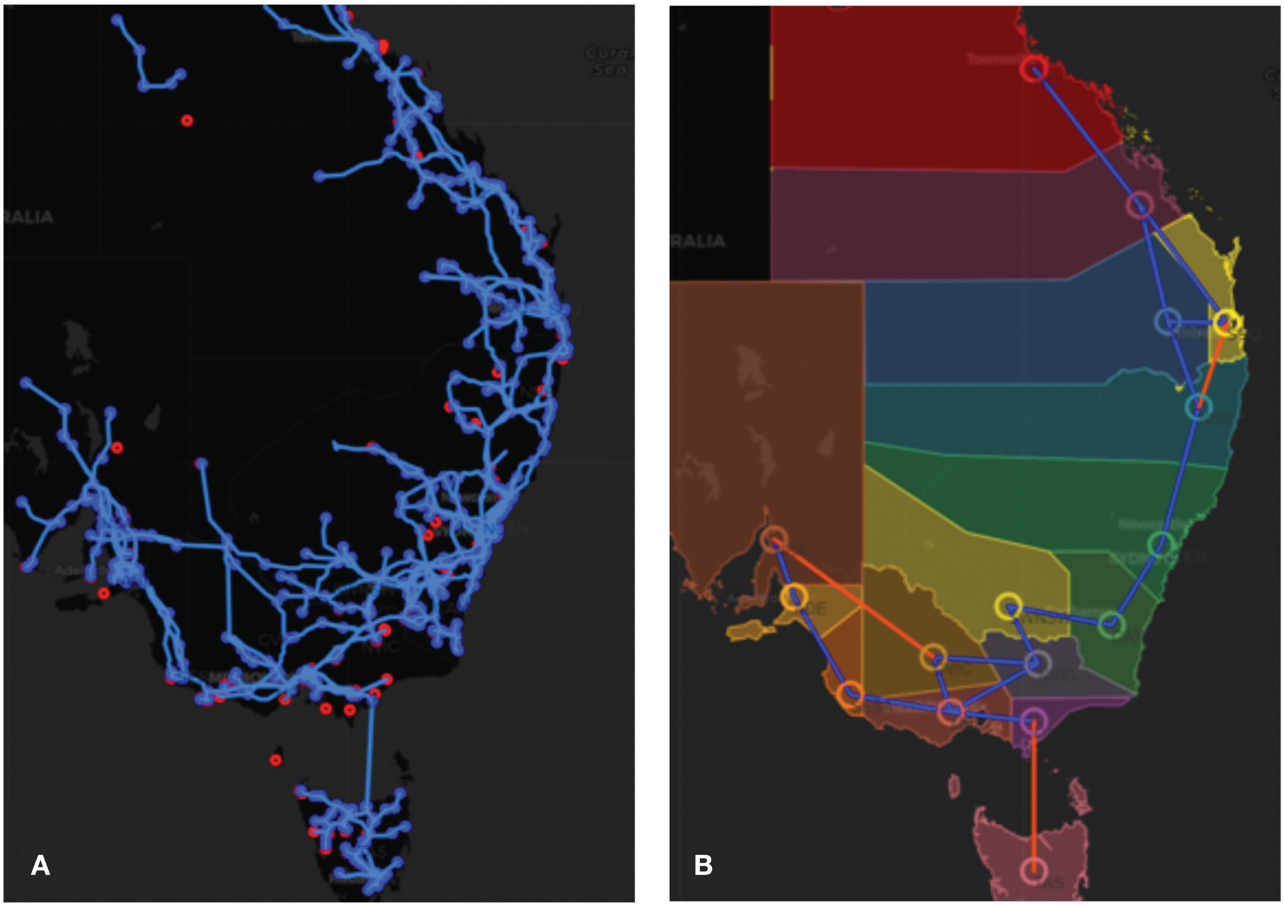

Figure 24 a) National Energy market Transmission lines (Geoscience Australia, 2017), generators and substations, and b) Simplified NEM used in the model

A.1 Past work

The NEM-CEED model was developed by Steven Percy at Victoria University and built on the 'UC_5' folder of the egrimod-nem model under a Creative Commons license. Aleksis Xenophon and David Hill (Xenophon and Hill, 2018) developed the egrimod-nem model in 2018 and made the Python code public on Git-Hub (egrimod-nem – GitHub, 2019). The egrimod-nem model aims to create a simplified configuration of the NEM to simulate the historical dispatch of generation in the National Energy Market to meet demand, though; egrimod-nem does not consider future network states, storage or capacity expansion.

A.2 Model formulation

This section describes the NEM-CEED model.[16] The objective function in (1) is the minimisation of the total cost of providing energy to the market plus the cost of unserved energy in all zones. The model is solved subject to Equations (2) to (24). Table 1 to Table 4 define the indices, variables, parameters and data sources in the model. Equation (2) defines $DS_{Z,t}$ as the zone operational demand plus the demand from charging or discharging battery storage or pumped hydro. Equation (3) is the capacity in the battery in each zone after charging and discharging. Equations (4) and (5) limit the charging and discharging of the zone battery and pumped hydro to be less than the installed power capacity. Equations (6) and (10) define the battery or pumped hydro level based on the number of hours of storage. Equation (7) is the level (in MWh) in the pumped hydro reservoir in each zone after charging or discharging the battery. Equation (11) defines the energy balance in all transmission zones, where the energy generated and imported equals the energy exported. Equation (12) defines the power flow limits of the transmission network. Equation (13) and (14) define the regional generation reserve provided by the regional generators and storage. The numerous equations constraining *BU, BI,PHU, PHI* have been emitted from this description to focus on the most important constraints in the model. These constraints ensure the model selects feasible values considering charging and discharging of storage. Equation (15) limits the total annual hydro generation quantity for each station to be less than the 2018 levels. These constraints function as a proxy for future rainfall; we do not consider rainfall forecasts in the model. Equation (16) defines the generation output as a function of minimum power and power above minimum to ensure coal generator output does not fall below stable levels. $MP_{g,t}$ varies over time to consider unit outages and is defined as the quantity offered by the generator to the market in the same reference year as the AEMO ESSO demand forecast used in the model. Equation (17) defines the change ramp up and ramp down output between time intervals. Equation (18) and (19) limit the generator ramping to be less than the generator ramp rates. Equation (20) and (23) define the upper limit of generator power output based on the NEM regional generation reserve requirements. Equations (22) and (23) limit the generation reserve provided by each generator to be less than the generator ramp-up and ramp-down capabilities. Equation (24) defines the renewable power used in each transmission zone. The difference between $R_{Z,t}$ and $RP_{Z,t}$ equals the renewable curtailment, normally caused by transmission bottlenecks.

The model is formulated in Pyomo (*Pyomo*, no date) and solved using Gurobi (Gurobi, no date). In this study the model is solved for one year of data at 30 minute intervals. To simulate the market in the future, the model takes forecast parameters from Table 3 (sources contained in the table), new transmission augmentation expected by the simulation year, (sourced from *Integrated System Plan For the National Electricity Market*, 2018) and expected dispatchable generation closure dates sourced from (AEMO, 2019a). When solved, the model result set contains all model variables in Table 4 at 30-minute intervals for the simulation year.

16. The model formulation presented here excludes the capacity expansion constraints in NEM-CEED, which were not required to produce the results in Chapter 5.

$$minimise \sum_{t \in T} \sum_{g \in G} C_g * G_{g,t} + \sum_{t \in T} \sum_{z \in Z} CU * U_{z,t} \quad (1)$$

$$(2)$$

$s.t.$

$$DS_{z,t} = D_{z,t} + BC_{z,t} - BD_{z,t} * RTE_B + PHC_{z,t} - PHD_{z,t} * RTE_{PH}$$

$$BL_{z,t} = BL_{z,t-1} + BC_{z,t} - BD_{z,t} \quad (3)$$

$$BC_{z,t} < B_z \quad (4)$$

$$BD_{z,t} < B_z \quad (5)$$

$$BL_{z,t} \leq B_z * BH \quad (6)$$

$$PHL_{z,t} = PHL_{z,t-1} + PHC_{z,t} - PHD_{z,t} \quad (7)$$

$$PHC_{z,t} < PH_z \quad (8)$$

$$PHD_{z,t} < PH_z \quad (9)$$

$$PHL_{z,t} \leq PH_z * PHH \quad (10)$$

$$\sum_{g \in GZ_z} G_{g,t} \ f - DS_{z,t} + R_{z,t} + U_{z,t} = \sum_{l \in L} TX_{l,t} * M_{l,z} \quad (11)$$

$\forall z \ in \ Z$ and $\forall t \ in \ T$

$$TZR_l \leq TX_{l,t} \leq TXL_l \quad (12)$$

$\forall l \ in \ L$ and $\forall t \ in \ T$

$$\sum_{g \in GR_r} GU_{g,t} + \sum_{z \in ZR_z} PHU_{z,t} + \sum_{z \in GZR_z} BU_z \geq \mathrm{RU_r} \quad (13)$$

$\forall r \ in \ R$ and $\forall t \ in \ T$

$$\sum_{g \in GR_r} GD_{g,t} + \sum_{z \in ZR_r} BI_z + \sum_{z \in ZR_r} PHI_z \geq \mathrm{RD_r} \quad (14)$$

$\forall z \ in \ Z$ and $\forall t \ in \ T$

$$\sum_{t \in T} G_{g,t} \leq HL_g \quad (15)$$

$\forall g \ in \ H$

$$G_{g,t} = MP_{g,t} + GMP_{g,t} \quad (16)$$

$\forall g \ in \ G$

$$GMP_{g,t} = GMP_{g,t-1} + GC_{g,t} \quad (17)$$

$\forall g \ in \ G$

$$GC_{g,t} \leq PI_g \tag{18}$$

$$\forall g \; in \; G$$

$$GC_{g,t} \geq -1 * PD_g \tag{19}$$

$$\forall g \; in \; G$$

$$G_{g,t} + GU_{g,t} \leq P_{MAX_{g,t}} \tag{20}$$

$$\forall g \; in \; G \text{ and } \forall t \; in \; T$$

$$GMP_{g,t} + MP_{g,t} + GU_{g,t} \leq PMAX_{g,t} \tag{21}$$

$$\forall g \; in \; G \text{ and } \forall t \; in \; T$$

$$GU_{g,t} \leq PI_g \tag{22}$$

$$\forall g \; in \; G \text{ and } \forall t \; in \; T$$

$$GD_{g,t} \leq PD_g \tag{23}$$

$$\forall g \; in \; G \text{ and } \forall t \; in \; T$$

$$R_{z,t} \leq RP_{z,t} \tag{24}$$

$$\forall z \; in \; Z \text{ and } \forall t \; in \; T$$

Table 1 Sets of model indices

Symbol	Set description
Z	All NEM transmission zones
T	All time index
GZ_z	All generators in zone z
L	All transmission lines linking the transmission zones
GR_r	All generators in a region r
ZR_r	All transmission zones in a region r
H	All hydro generators in the NEM
GEN	All generators in the NEM
R	All NEM regions

Table 2 Model indices

Symbol	Index description
g	Generator index referring to one generator in the NEM.
t	Time index referring to one time index
l	Transmission line index referring to one transmission link in the NEM transmission network.
z	Zone index referring to one transmission zone.
r	Region index refers to one region in the market.

Table 3 Model parameters

Symbol	Parameter description	Data source
D	The demand at each interval for each transmission zone	2019 ESSO, OPOS demand (*NEM Electricity Statement of Opportunities – Australian Energy Market Operator,* 2019) disaggregated to transmission zones using the disaggregation factors in Table 4.4 from (Roam Consulting, 2013)
M	Matrix representing zone connections	Formed using the transmission network configuration in Figure 4.3 from (Roam Consulting, 2013)
MP	The minimum power output for a generator	Formed using minimum values in (*NTNDP database – Australian Energy Market Operator,* 2018) and the maximum availability sourced from the generator bids available at (AEMO, 2019b)
C	The short run marginal cost for every generator	SRMC was produced using fuel cost and heat rate data sourced from the *2019 ISP Input Assumptions Workbook* (AEMO, 2019a)
PMAX	The maximum power output for a generator	Sourced from the generator unit bids coincident with the AEMO reference year forecast available at (AEMO, 2019b)
RU	Regional generation reserve up	*ISP Input Assumptions Workbook* (AEMO, 2019a)
RD	Regional generation reserve down	*ISP Input Assumptions Workbook* (AEMO, 2019a)
CU	The cost of unserved energy	*ISP Input Assumptions Workbook* (AEMO, 2019a)
RP	The renewable generation for each zone	2019 ESSO, Solar and wind Traces (*NEM Electricity Statement of Opportunities – Australian Energy Market Operator*, 2019) and list of projects from (Clean Energy Council, no date). Capacity growth after 2022 was source from the Neutral scenario in the 2018 ISP (*Integrated System Plan For the National Electricity Market*, 2018)
BH	The hours of battery storage	*ISP Input Assumptions Workbook* (AEMO, 2019a)
PHH	The hours of pumped hydro storage	*ISP Input Assumptions Workbook* (AEMO, 2019a)
TXF	Forward flow limit on each transmission line	*Modelling Transmission Frameworks Review* (Roam Consulting, 2013)
TXR	Reverse flow limit on each transmission line	*Modelling Transmission Frameworks Review* (Roam Consulting, 2013)
RTE_B	Battery storage round trip efficiency	*ISP Input Assumptions Workbook* (AEMO, 2019a)
RTE_{PH}	Pumped hydro storage round trip efficiency	*ISP Input Assumptions Workbook* (AEMO, 2019a)
B	The battery capacity in each transmission zone	The Neutral scenario in the 2018 ISP Database (*Integrated System Plan For the National Electricity Market*, 2018)
PH	The pumped hydro capacity in each transmission zone	The installed capacity in the Neutral scenario in the 2018 ISP Database (*Integrated System Plan For the National Electricity Market,* 2018) installed in the largest generating transmission zone.
HL	The annual hydro output for each hydro station	The installed capacity in the Neutral scenario in the 2018 ISP Database (*Integrated System Plan For the National Electricity Market,* 2018) installed in the largest generating transmission zone.

Table 4 Model variables

Symbol	Variable description
R	Renewable power generation used to provide demand or charge storage in each zone
PI	Generation ramp up quantity in each time interval
PD	Generation ramp down quantity in each time interval
TX	The flow on each transmission line
DS	The zone demand plus the energy used to charge the battery storage
BL	The energy stored in battery storage in each transmission zone
BD	Battery discharge in each zone
BC	Battery charge in each zone
PHL	The energy stored in pumped hydro in each transmission zone
PHC	Pumped hydro charge in each zone
PHD	Pumped hydro discharge in each zone
G	The total power output of each generator
U	The quantity of energy unserved
GU	The upward generation reserve provided by each generator
GD	The downward generation reserve provided by each generator
GMP	The power output above the generator minimum
GC	The change in generator power output between time intervals
TX	Transmission flow on line

A.3 Model limitations

Facilitating the trade and distribution of energy to the south and eastern states is very complex. The NEM-CEED model aims to capture as many realistic characteristics of the NEM as possible by considering the most important complexities of cost, the transmission network and engineering limitations. With computational and data availability restrictions come some model limitations, these include:

- Station-specific dispatch rather than unit-specific dispatch; this ignores unique engineering considerations applied to a particular generation unit within a generation station.
- The model assumes a short run marginal cost based on fuel cost forecasting in the 2019 ISP and fixed generator heat rates. This approach dispatches a generator based on a cost reflective merit order. In reality, contract positions and strategic interaction amongst generators, such as withholding capacity, may influence the dispatch order.
- We constrain the hydro generator annual dispatch to 2018 historical quantities. In future years, the rainfall may vary from 2018 levels, influencing the dispatch of other fuel types. However, this would influence gas generator dispatch instead of baseload black and brown coal.
- The transmission network is simplified into distinct transmission zones as in the (*NTNDP database – Australian Energy Market Operator,* 2018) with limit sourced from (Roam Consulting, 2013). A higher number of transmission zones could provide additional insights into the transition of the NEM, though no data for intra-regional limits over a smaller geographical area exist for the NEM.

A.4 Model back-cast to 2018

Back-casting can provide confidence that a model correctly represents the actual system. Here we have applied the model to back-cast the NEM in 2018 and compared to actual outcomes. Instead of AEMO's ESOO demand forecast in the back-cast, we use actual 2018 historical regional demand and renewable production.

Figure 25 shows the back-cast wholesale demand and production and aggregated exports for Victoria for 2018 compared to the actuals for that year. This shows that our model reproduces export quantities and brown coal production accurately. The variation in export may be attributable to variations in the interconnector ratings used in our model, since the version of the model applied in this report uses the maximum interconnector rating. In reality, interconnector ratings vary vastly from the maximum values. The gap between back-cast and actual is not large but we intend to develop interconnector ratings in further development of the model.

Figure 26 shows the historical dispatch and model back-cast dispatch of black coal generators. Again the model reproduces the dispatch quantities accurately. One difference is the lower Bayswater Power Station and high Eraring Power Station production in the back-cast. This difference might be attributed to AGL, in 2018, bidding Bayswater far above marginal costs, as described in Mountain and Percy (2019). The same situation is likely to explain the difference in dispatch of Stanwell Power Station. The model also achieved a very high level of accuracy for brown coal generators as shown in Figure 27.

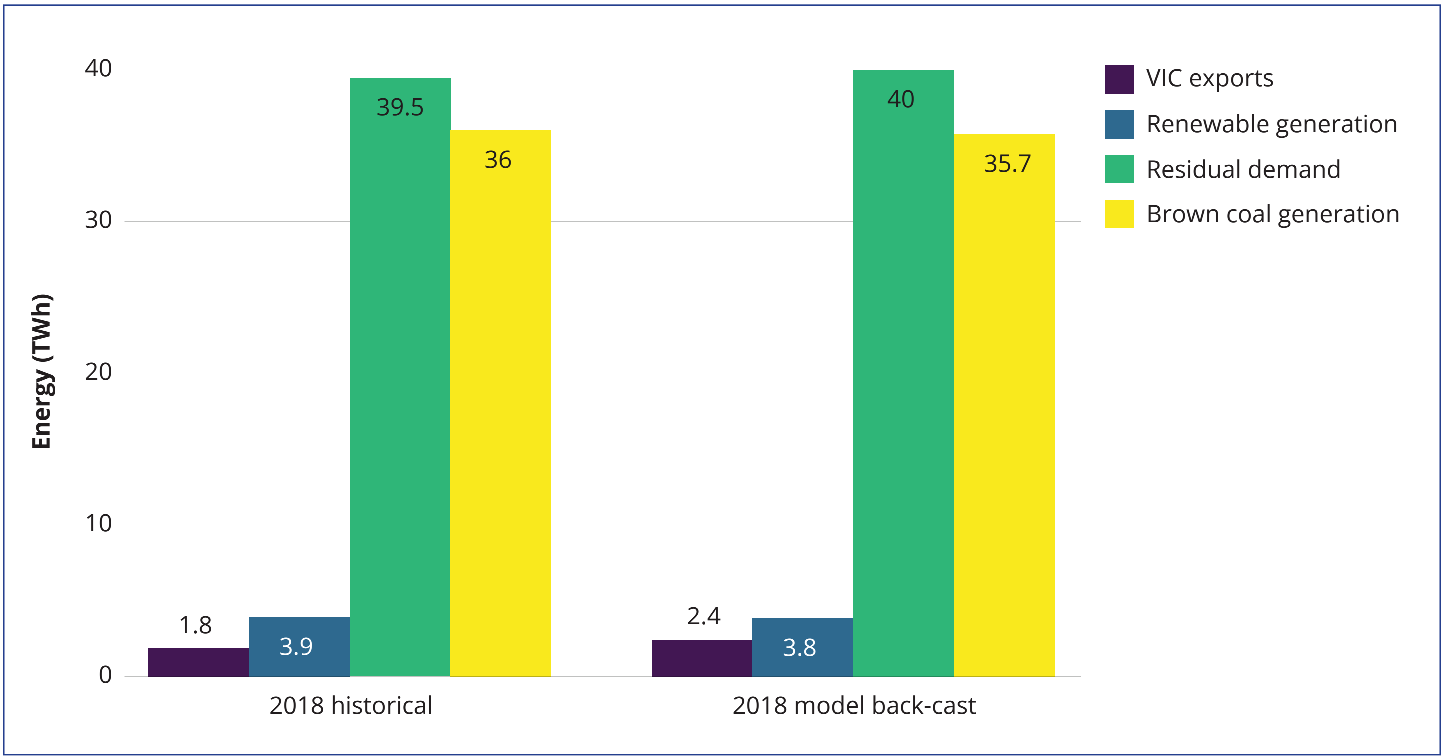

Figure 25 2018 Victorian wholesale demand, production and exports back-cast result compared to 2018 actuals

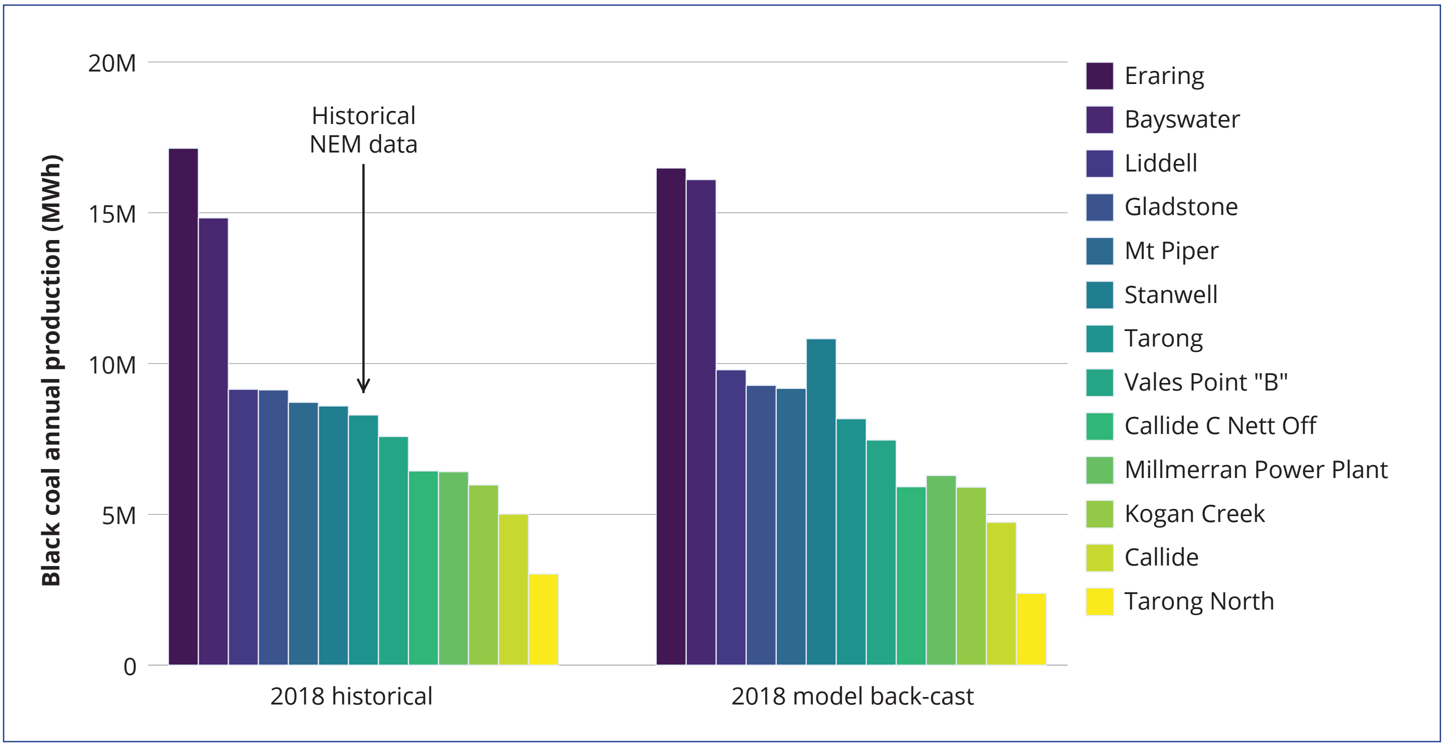

Figure 26 2018 black coal production back-cast result compared to historical data

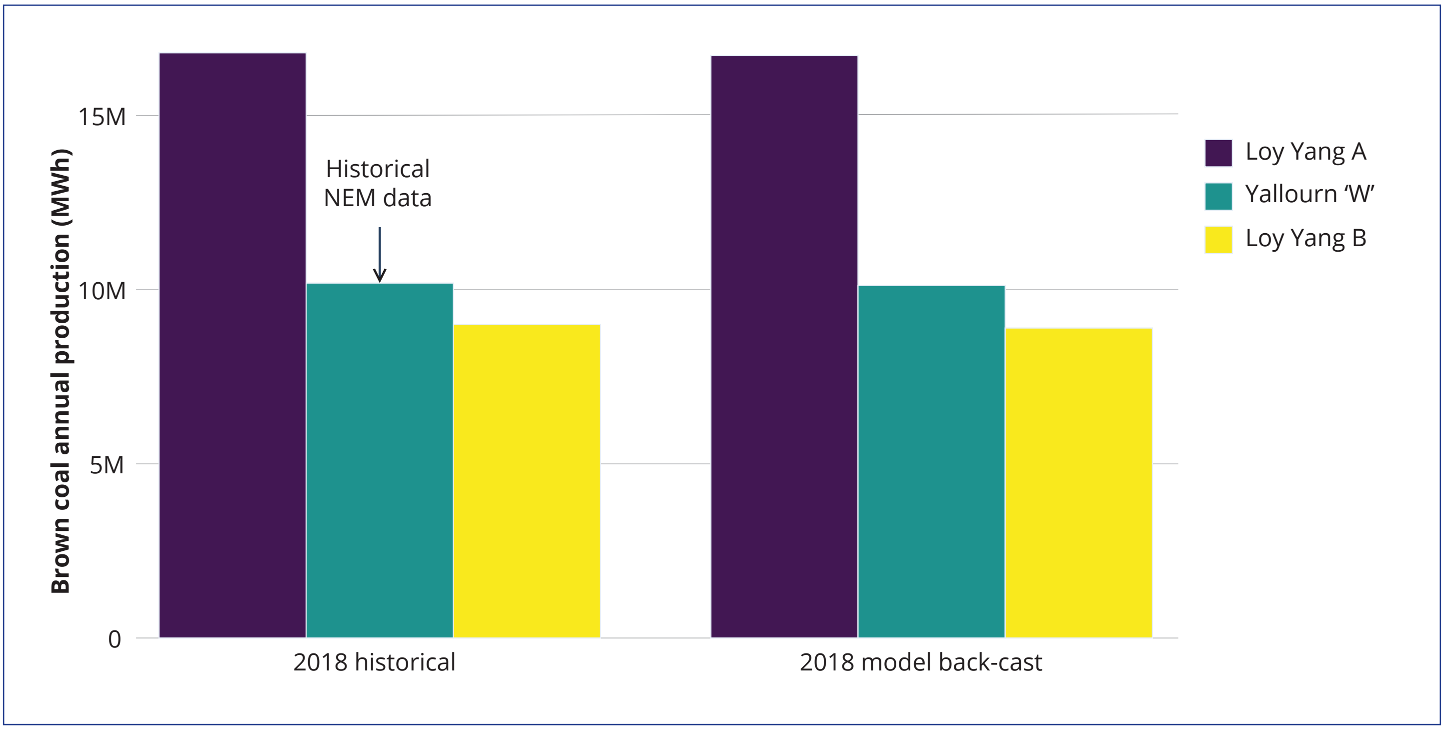

Figure 27 2018 brown coal production back-cast result compared to historical data

Victoria Energy Policy Centre

Victoria University, PO Box 14428
Melbourne Victoria 8001 Australia
City Flinders Campus
Level 13, 300 Flinders St, Melbourne

vepc.org.au

Victoria Energy Policy Centre

VICTORIA UNIVERSITY
MELBOURNE AUSTRALIA