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There's a Better Way To Manage Coal Closures Than Paying To Delay Them

How the Energy Security Board Made the Right Diagnosis but Recommended the Wrong Treatment

Executive Summary

This report has been produced in response to a recommendation flowing from the Energy Security Board's post-2025 market design review. This review investigated whether the market design for the east coast main electricity grid (known as the National Electricity Market or NEM) was appropriately structured given expected substantial changes in the future electricity supply mix.

This report focuses in on one recommendation strongly backed by the Federal Energy Minister Angus Taylor for the introduction of a capacity market into the NEM, which is currently an energy-only market. Our analysis suggests that this capacity market mechanism should be rejected by state government energy ministers, as there are better options available to address challenges facing the NEM which have been identified in the ESB's review.

Under the current energy-only market design, electricity generators are only compensated by the energy market operator for the megawatt-hours of electricity they deliver to the grid and market customers only pay for the megawatt-hours of electricity they consume. Under the ESB's proposal this would continue, but in addition market customers would need to also pay generators for capacity credits. The credits would be awarded to a generator based not on the electricity they actually produced but rather an assessment of the maximum electricity they could potentially produce during periods of time that energy officials considered to face risks of supply outages (black-outs). By definition these would be periods when wind and solar generation was low so these plants would be largely excluded from qualifying for capacity credits.

The Energy Security Board proposes to develop the detailed design of the capacity mechanism over the next 12-18 months, with the starting point for the design work being what they have entitled a Physical Retailer Reliability Obligation proposal.[1]

In this report, we have chosen to evaluate this proposal for a PRRO capacity market based on an assessment as to how well it helps address a series of problems or

[1] Energy Security Board. Post-2025 Market Design Final Advice to Energy Ministers Part A. 27 July 2021.

ailments that the Energy Security Board themselves have indicated afflict the National Electricity Market. For the most part we believe the ailments identified by the Energy Security Board are valid and act to deter private sector participants on their own initiative and without support from governments from making timely investments that would ensuring the adequate supply of electricity to ensure reliability. In addition to evaluating the ESB's proposed remedy we examine various alternative policy options to deal with each of the ailments.

The ESB has correctly identified key ailments facing the National Electricity Market.

Throughout the post 2025 market design process, the ESB has done a good job of highlighting key challenges facing the National Electricity Market. The ailments they identify as inhibiting timely investment in supply to ensure reliability mainly revolve around: a) high levels of uncertainty around coal exits; b) myopic market contracting behaviour; c) early mover disadvantage in power technologies subject to cost deflation; and d) unpredictable government intervention.

Recent reports IEEFA have written on this topic have come to the following conclusions.

1. The financial viability of several coal generators is under threat, such that there is a risk of abrupt, unexpected closure. It is vital to manage coal exit uncertainty.[2]

2. There is a large amount of dispatchable capacity coming online, which buys energy planners time to manage the exit of coal generators in an effective manner without threatening reliability.[3]

3. The Energy Security Board capacity mechanism proposal has the potential to impose a substantial additional costs on electricity consumers; with experience from Western Australia's capacity market indicative of annual payments between $2.9billion to $6.9 billion a year. This would be allocated primarily to existing conventional generators, and would exacerbate uncertainty rather than reduce it.[4]

4. The Energy Security Board's own capacity market benefit calculation cannot be relied upon to provide a full picture of the costs and benefits of the capacity mechanism.[5]

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[2] IEEFA. Fast Erosion of Coal Plant Profits in the National Electricity Market. February 2021.
[3] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[4] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[5] RenewEconomy. The dubious modelling behind the Energy Security Board's capacity market proposal. 8 September 2021.

From these previous reports, is clear that such a massive change to the National Electricity Market, involving a new, perpetual multi-billion dollar annual payment given to primarily conventional generators is not justified, nor justifiable, on a cost-benefit basis. It is also clear that a capacity mechanism will not address the investment uncertainty challenge that the National Electricity Market currently faces.

The capacity mechanism does not address the ailments facing the National Electricity Market.

In this report, we find that the capacity mechanism does not address the ailments facing the National Electricity Market, as it will increase uncertainty around coal exit, will not increase the duration of contracting, does nothing to combat first mover disadvantage and does not address the underlying reasons for why governments are regularly intervening in the electricity market.

Energy ministers should instead consider a combination of the following measures as a starting point, which could be further developed and evaluated by a genuinely independent panel of energy market and decarbonisation technology experts:

- A strengthened regulatory regime for ensuring owners of large and aged power stations give at least three and half years notice of exit based on providing an upfront bond rather than depending on application of penalties only once a breach occurs (which is the current case). This should be complemented by the use of financial and engineering audits every three years of these large, aged power stations to undertake stress-tests of their ability to maintain reliable operation and their risk of abrupt exit.

- Enact legislation that sets out a schedule for coal generating units to be steadily retired once set amounts of new reliable replacement capacity are built. This will give investors in new capacity enhanced clarity and incentive to build new plant but such investments will be primarily guided by expected returns in the electricity market, and should allow investors wide discretion on the plant technology that best suits market needs. The specific order in which coal units are retired can be determined through an array of different alternative methods which could include: voluntary nomination by owners (likely if plant is loss making and notice period bond is returned); an auction process where units are paid to retire; or regulatory criteria (e.g. evaluation of their relative reliability or unplanned outage risk; emissions intensity, age).

- Provide a floor price underwriting mechanism to encourage new competitors that build new dispatchable capacity. This could be modelled along the lines of the ACCC's 2018 electricity market review recommendation where a new entrant would be expected to first secure a 3 year contract to provide firmed power supply to customers outside of the major government and private sector retailers. The price floor would then cover years four to seven of the plant’s life.

- Implement the emissions obligation component of the National Energy Guarantee or an alternative, long term mandatory obligation for electricity retailers or generators to reduce emissions based on tradeable certificates. The emission target should be based on a steady reduction in annual emissions in line with States’ net zero by 2050 targets with interim targets reducing emissions well below an expected business as usual trajectory.

- Contracts with individual generators to remain open as per the Victorian Government arrangement with Yallourn should be avoided. If such agreements are entered into they should include a schedule (detailed publicly) for faster retirement of generating units than agreed based on when suitable replacement capacity comes online. That replacement capacity should not need to come from the owner of the generator which is party to the support contract.

- If merited based on an evaluation of the risk to reliability from abrupt coal exit in advance of completion of Snowy 2.0, augment the existing energy-only market with enhanced energy reserve mechanisms.

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Introduction: The ESB's Diagnosis

In their post 2025 Market Design paper, the Energy Security Board (ESB) has done a good job of diagnosing a lack of investor confidence in the main east-coast electricity grid – the National Electricity Market or NEM. As we will outline, there are several challenges which have resulted in investor confidence concerns.

Unfortunately, the ESB has prescribed a treatment to this malaise – an obligation on consumers via their power retailer to pay a fee to generators based on their "dispatchable" capacity – which will make things worse rather than better for those that might invest in the new flexible and firm resources that we need. This proposed "solution" looks to have been designed by a group of people concerned predominantly with one thing – taking care of the owners of and investors in existing power plants; not investors that might build new generation or storage.

Before explaining the flaws with the ESB's capacity mechanism proposal, it's first worth examining the diagnosis of ailments facing the NEM which the ESB got right. Exploring the ailments helps us to understand why the ESB's treatment is poorly formulated, and helps guide us as to what Governments should do instead.

The ESB is absolutely correct in identifying that the financial viability of a number of coal-fired power plants are under threat due to an influx of wind and solar. In our report, Fast Erosion of Coal Plant Profits in the NEM[6] released in February this year, we detailed how extra wind and solar capacity expected to join the grid after 2018 and before 2025 will push wholesale power prices down considerably while also substantially reducing sales volumes for coal generators. For up to five of the NEM's existing coal power plants, the diminished wholesale spot market revenue will be insufficient to cover their costs. This makes the exit of at least one plant in its entirety (or several individual generating units from across several of these power plants) by 2025 highly likely.

The exit of at least one coal plant in its entirety is highly likely.

The ESB is also correct that for power reliability to be maintained with the exit of coal power stations, there is a need for solar and wind to be complemented with technologies which can vary their output up and down on command - that are "dispatchable".

We would also agree with the ESB that there are a range of elements affecting the electricity market that create a high degree of uncertainty for investors in trying to evaluate whether or not it's worthwhile to build new dispatchable capacity and

[6] IEEFA. Fast Erosion of Coal Plant Profits in the National Electricity Market. February 2021.

when they should build it. At present, this uncertainty shouldn't present a problem for power system reliability because around 7,000 megawatts (MW) of dispatchable capacity has been committed by investors or promised by politicians (mainly the Federal Government) since 2017 when Hazelwood coal power station exited and is due to be complete by 2027.[7] This is around 12% of the current capacity of the NEM.

However, given almost all this capacity is a result of government commitments and several of these projects appear to have highly questionable economics[8], there remains a legitimate long-term concern regarding how to create an environment more conducive to future private sector investment in dispatchable plant.

The ESB diagnosed the following ailments with the market which make it difficult for investors to determine the medium to long-term electricity market supply-demand balance, and the prices, that are critical to making an informed decision about whether it is financially worthwhile to build new dispatchable capacity:

1. High levels of uncertainty about when coal power plants might exit and therefore when it would be opportune to build replacement capacity
2. Market contracting behaviour is highly myopic, with little to no contracting for firm power products beyond 3 years
3. Technology costs for batteries are declining over time which acts to penalise early movers investing in this technology
4. Government are regularly intervening to build new power supply, although complicating matters is that this often occurs in an ad hoc and unpredictable manner.

This is a very good list which the ESB should be commended for clearly diagnosing.

Following we present why the ESB's proposed capacity payment via a Physical Retailer Reliability Obligation (PRRO) doesn't particularly help with these

[7] Our report, Energy Security Board's Capacity Payment: Burden on Households, published in August 2021, details that reliability is not at risk when taking into account the scheduled closure of Yallourn, Vales Point and Callide B, as there is a very large amount of dispatchable capacity coming online over the period from 2017 to 2027. However, there is a short-term risk to reliability due to the potential for abrupt, earlier than expected coal plant closure by 2025, as identified in our report, Fast Erosion of Coal Plant Profits in the NEM, published in February 2021. Snowy 2.0 is due to be completed in 2026, and there are potential for delays, especially given the Federal Government failed to ensure transmission capacity commitments were co-ordinated in alignment with commitment to the Snowy 2.0 upgrade. Investors are not incentivised to build capacity in advance of Snowy 2.0 coming online, as once it comes online their profits will reduce. Therefore, there may be a short-term reliability issue if abrupt coal exit occurs in advance of Snowy 2.0 becoming operational.

[8] As some examples of analysis highlighting issues with the economics see: Hyslop (2018) Snowy 2.0 – Is the reward worth the risk; Mountain, Percy and Woodley (2021) The Kurri Kurri Power Station: charging taxpayers for hot air; Mountain and Percy (2020) Wrong way, go back: An analysis of the economics and greenhouse gas impact of Marinus Link and Battery of the Nation

challenges and propose alternative policy or regulation that could be considered by Energy Ministers.

Ailment 1 – High Levels of Uncertainty Around Coal Exits

Uncertainty surrounding when coal power plants might shut or when they might suffer from an irreparable failure is probably the number one inhibitor to timely investment in new dispatchable capacity. The NEM is entering a period of substantial excess supply which will mean for much of the time electricity prices will be depressed to levels that will make returns unattractive for new projects, while also reinforcing conditions that make coal withdrawal likely.[9] Ideally, new dispatchable capacity would be operational before any coal plant withdrawals occur. Unfortunately, it is likely that prices will only rise to levels attractive to new investment once part or all of a coal plant exits. This is the difficulty of the large, lumpy nature of coal generators. The result is that it is rational for an investor to wait until they have a high degree of confidence about any coal plant exits before committing to building a new plant.

The ESB could have strengthened the effectiveness of the legal regime which currently requires the owners of coal generators and other large power plants to give at least three and half years notice of closure. Yet while it conceded the current rules around notice have loopholes that make them ineffective, the ESB did not pursue options to strengthen the regime.[10]

Instead, the ESB has put forward a scheme that will grant coal generators a financial lifeline which, while it will extend their viability, does not resolve the fact that many are very old and beset by high levels of carbon and economic risk that means they are subject to sudden, unexpected withdrawal. At the same time, while these large power plants remain in operation, they will act to deter investment in new dispatchable capacity.

The ESB have put forward a scheme that will grant coal generators a financial lifeline.

While the ESB has tried to suggest a capacity payment proposal isn't a bailout for coal and is about supporting new investment, further scrutiny suggests something different.

- **The proposed capacity mechanism will provide coal generators with a new revenue stream in spite of their lack of flexibility which will**

[9] IEEFA. Fast Erosion of Coal Plant Profits in the National Electricity Market. February 2021.
[10] Energy Security Board. Post-2025 Market Design Final Advice to Energy Ministers Part B. 27 July 2021.

> **extend the uncertainty overhanging the market about the timing of coal plant exits.**

The ESB has been quite anxious to protest the idea that its proposed capacity payment is in reality an attempt to bailout coal generators[11], an initiative that has been nicknamed by some as "The Coal Keeper Tax". According to the ESB, the capacity payment will instead reward a plant for flexibility[12] (and therefore won't help coal due to inflexibility). However, the ESB hasn't explained in any meaningful detail how any capacity mechanism will do this.

Minister Taylor has also made the same argument recently, saying "coal would only benefit to the extent it was able to respond flexibly"[13]. despite having previously said that the capacity mechanism will "incentivise our existing thermal generators to remain in our market," and that, "a capacity mechanism can help keep dispatchable generators from shutting down too early, so that consumers don't face price spikes like we saw when Hazelwood closed in 2017."[14]

Yet based on what we know so far of the design of the capacity mechanism, it appears coal power plants will undoubtedly qualify for capacity payments. Our understanding is that coal qualifies in all other capacity markets where it has been a significant supply of energy, with an exception of Italy. Most importantly, the ESB and Minister Taylor have publicly acknowledged coal will be eligible. The very small number of companies that have expressed strong support for a capacity payment all have one thing in common – they own coal-fired power stations.

Clearly the capacity payment will be provided to coal generators.

What the ESB have failed to acknowledge is that coal power plants have a way of making up for their lack of flexibility such that they can credibly claim they can be there to deliver capacity when the ESB's vaguely defined "at risk" periods occur[15]. With no carbon credit revenue available to renewable energy projects and LGC prices soon to collapse, coal power plants will only need to bid slightly negative prices for a few hours prior to the typical 3pm-9pm post solar demand peak, in order to push wind and solar power plants offline. That will then leave coal power

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[11] RenewEconomy. "Missing markets": Why energy storage projects are being sidelined in Australia. 16 September 2021.
[12] h RenewEconomy. "Missing markets": Why energy storage projects are being sidelined in Australia. 16 September 2021.
[13] The Australian. Power shake-up can drive emissions down says Angus Taylor. 26 August 2021.
[14] The Hon Angus Taylor MP. A market design to deliver for consumers. 26 August 2021.
[15] Unfortunately, in spite of a 2 year long process to develop its recommendations, the ESB has provided an incredibly vague level of detail around the type of capacity mechanism it would like to implement, while still asking for Ministers to give sign-off to proceed with its implementation. In essence they are asking stakeholder and Ministers to "trust us". Yet as explained in this paper there is good reason to believe that the capacity model they have in mind will favour existing incumbent generators while doing little to support new investment on a timely basis.

plants, in spite of their inflexibility, online and therefore ready to cash in on both capacity credits and also high energy market prices over the late afternoon and evening peak period. The value of the capacity credit and high energy prices (usually above $100/MWh during these periods), should readily make up for the negative prices sustained in the prior hours.

Based on the value of capacity payments we commonly see in other markets, coal power plants financial position will be significantly improved, helping to make up for poor returns during periods that might not meet the ESB's definition of "at risk".

- **The capacity mechanism also appears likely to cut-out batteries and demand response via a dubious emphasis on "long duration" resources.**

The second reason that the capacity payment is structured to favour incumbent coal while working against new entrants – that are most likely to favour batteries and demand response as firming technologies – is obscured within the ESB papers but has been brought to light in statements by Minister Taylor.

In The Australian newspaper, in response to criticism that the capacity payment will delay the exit of coal generation, Minister Taylor responded,

> *"Well it's wrong… If you read page 40 of the report, it says gas, hydro and long duration storage are likely to benefit from the capacity mechanism.*[16]

What is of particular interest here is that Minister Taylor didn't simply say that "storage" would benefit from the capacity payment, instead he included the additional words, "long duration".

Batteries and demand response technologies are not mentioned at all.

At various points throughout the ESB papers it repeatedly suggests that the capacity mechanism could support batteries and demand response. But page 40 of the ESB's Part B final advice does not mention batteries or demand response at all. It instead states,

> *"Beyond 2025 the types of resources that are expected to be best incentivised by a certificate scheme are those resources that are flexible, reliable and economically competitive when operating at low-capacity factors. Peaking gas plants such as Open Cycle Gas Turbines (OCGTs) and hydro units are most likely to be suited to such schemes in the short-term, while longer duration storage will become well suited to covering such shortfalls – and therefore should be facilitated by a certificate scheme – as the technology develops."*

[16] The Australian. Power shake-up can drive emissions down, says Angus Taylor. 26 August 2021.

A capacity payment which is skewed to heavily favour generators that can deliver capacity over a long duration will have significant implications in which type of plants are supported by the mechanism.

So, what exactly is 'long duration'?

Unfortunately, this pivotal term is not properly defined by the ESB anywhere in the final advice. However in the Australian Energy Market Operator's (AEMO) 2020 Integrated System Plan, three categories of storage are defined:

- short (less than 2 hours)
- medium (between 4 to 12 hours)
- deep storage (24 hours or longer).

From AEMO's definitions, long duration would imply a battery or demand response would need to deliver a megawatt of capacity for 12 continuous hours or longer in order to qualify for a capacity credit.

A capacity payment that only went to capacity that could deliver over 12 hours would work exceptionally well at excluding both batteries and demand response while favouring the incumbent coal, gas and hydro generators.

The east coast U.S. capacity market (the PJM) provides a precedent for this kind of approach as battery systems only qualify for a capacity credit if they deliver the capacity for 10 or more continuous hours and precisely nothing if they deliver the power for any period less than that (although they are now looking to reform this highly questionable regulatory requirement).

Batteries and demand response technologies can deliver a megawatt of capacity at quite a competitive cost.

Batteries and demand response technologies tend to be good at delivering a megawatt of capacity extremely rapidly, far faster than coal and gas plants. In addition, they can deliver a megawatt of capacity at a competitive cost relative to building a new gas plant and with low ongoing fixed operating costs. However, this cost competitiveness tends to be constrained depending on how long it is provided. If you need a megawatt of capacity for 2 hours or less, then batteries and demand response are hard to beat. In addition, battery costs are declining such that they will soon be the superior choice over 4 hours. This will steadily extend in duration as they decline in costs such that by 2030, one could expect batteries will be the best choice for applications requiring 6 hours of service. But it seems unlikely that batteries could manage to reach cost competitiveness over a 12-hour duration for some time to come.

While the longer a plant can deliver capacity the better, modelling using historical weather patterns suggests that short duration storage can fill the vast bulk of the gaps left by exiting coal.

The main challenge the NEM faces for reliability over the next decade and a half if coal exits is managing a narrow window of time between when solar output drops away at around 3pm until 9pm over which demand for power remains high.[17] This is a six-hour window, not 12 hours plus.

This relatively short (less than 6 hour window) is verified by modelling data published by AEMO. In its 2018 Integrated System Plan (ISP), AEMO included a sensitivity analysis examining how the inclusion of pumped hydro projects Snowy 2.0 and Tasmania's Battery of the Nation might alter outcomes relative to its least cost pathway. This analysis reveals that these projects would add vastly more energy storage duration or gigawatt-hours (but not short-term instantaneous megawatts) than required to ensure reliability. In addition, under this modelled scenario where renewables rose to represent 75% of supply and 14,000MW of coal was shut, the average duration of energy stored per megawatt of capacity was 5 hours.

Unfortunately, AEMO's more recent 2020 Integrated System Plan only provides quite broad breakdowns on the nature of the storage that is installed under each of its scenarios with no quantification on the precise gigawatt-hour (GWh) of energy storage required. Nonetheless, the data which is published for the 2020 ISP Step Change Scenario also strongly suggests substantial coal closures can be accommodated predominately through an expansion in batteries providing around 6 hours duration or less, with not much long duration storage required for the next decade and half beyond that already provided by Snowy 2.0.

There is limited need for long-duration resources.

Further, analysis by the Victorian Energy Policy Centre of the economics surrounding the proposed New South Wales Kurri Kurri gas/diesel generator[18] and Tasmania's Battery of the Nation Pumped Hydro[19] initiative have also found that there is limited need for long-duration resources.

Given these facts, this preference for the capacity payment to heavily favour long duration resources suggests it will not do much to support the new investment we actually need, instead just helping the existing incumbent conventional power plants. This becomes especially apparent once one considers the fact that the

[17] IEEFA. Fast Erosion of Coal Plant Profits in the NEM. February 2021.
[18] Victorian Energy Policy Centre and Victoria University. The Kurri Kurri Power Station: charging taxpayers for hot air. 2021.
[19] Victorian Energy Policy Centre and Victoria University. An analysis of the economics and greenhouse gas impact of Marinus Link and Battery of the Nation. 2020.

proposed favoured model for the capacity mechanism does not support long-term contracting, which we examine later in this paper.

For those interested in further detail about this issue there is an appendix that goes into more detail about what the AEMO ISP data shows in terms of short versus long-term duration storage needs.

ESB Is Recommending Temporary Relief From Symptoms but not a Long-Term Cure to Ageing Coal Plants

The introduction of a capacity payment could certainly help to bolster the financial viability of coal-fired power stations and therefore slow the rate of capacity closures. However, it won't remove the climate change cloud that hangs over these highly polluting and in many cases very old assets. Owners of these plants can be expected to continue to treat them as assets with little long-term future for which capital should be severely rationed to investments delivering short paybacks. Financial markets are also likely to remain reluctant to lend or invest in them. In this respect, capacity payments will essentially work a bit like a drug that temporarily alleviates pain but does nothing to cure the underlying ailment.

If capacity payments are investigated further or introduced, electricity system reliability will remain hostage to very large and old power plants that owners operate with an eye to the short-term. This is likely to mean steadily deteriorating levels of plant reliability. As these power plants are so large, unplanned outages where such plants break-down with little or no warning can leave the market operator scrambling to bring on other resources to make up for the shortfall, even where there is plenty of capacity in place because of lags in ramping up this output.

The disruptive results of such catastrophic failures were evident earlier this year when Callide Power Station in Queensland suffered an explosion and Victoria's Yallourn Power Station's output was curtailed due to the risk of a mine collapse and flooding as a result of severe rains. These events occurred during periods that wouldn't typically be considered periods that posed risks to supply adequacy, yet were still highly disruptive.

It's worth noting that the Hazelwood coal plant showed all the critical signs of skimped maintenance that ultimately led to a rapid and disruptive closure. A large mine fire lasted several weeks due to inadequate remediation and fire suppression and a Work Safe inspection revealed a range of serious problems with plant safety.[20]

[20] ABC Gippsland. Worksafe notices detail extent of repairs needed at Hazelwood power station. 1 December 2016.

At the same time, a new revenue stream given to coal generators means investors face even greater doubts as to when the coal plant might exit and therefore whether they should proceed with something that might replace it. Also, if governments chose to introduce such a payment it sends the signal that investors should be wary of pre-emptively committing to new plants in advance of certainty about coal exits because Australian Governments are prone to take rash actions to prevent coal exits.

Investors face even greater doubts as to when the coal plant might exit.

Given all of these negative impacts of any capacity mechanism, in what follows we outline some alternative options to create greater certain around coal generator exits.

Alternative Options To Reduce Uncertainty Around Coal Exits

- **Strengthen notice period regulations via a financial bond mechanism (improve clarity)**

The first option is to ensure owners of large power plants adhere to their obligation to give adequate notice of withdrawal. At present, any financial penalties for breach of notice of closure rules are applied after the breach has occurred. This is problematic because the financial penalty at that point may be of little consequence if the entity is insolvent, and withdrawal of operating licences may be of little consequence if the entity is not operational.

Instead, the regulatory regime should require operators of large power plants greater than 20 years of age, whose withdrawal poses risks to the reliability of supply (500MW in aggregate capacity or greater), to put up a financial surety or bond covering the next 42 months of operation in advance. This means the bond would be required only at plants that pose a significant risk of abrupt withdrawal.

As explored in our previous report[21], operators of these plants would be required to provide bonds calibrated to the amount of megawatts of each of their generating units that they intended to run in each month of the next 42-month period. This bond would be a one-off cost that would be rolled over as each month passed or refunded if the operator chose to withdraw a plant from service with 42 months or more notice.

To provide for a reasonable level of flexibility, if the operator wished to withdraw their plant without providing 42 months' notice, they could still reclaim their bond covering the period the plant was closed in advance of 42 months' notice, if an assessment by AEMO deemed this did not put reliability at risk. However, once an operator elects to withdraw a plant, they could not revise that decision later without incurring a much larger payment to the regulator than the initial bond cost. Without

[21] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.

this penalty in place, at-risk generators could use mothballing as a loophole to avoid incurring the bond until the last minute.

The financial value of the monthly bond should be set at a level that would provide a strong incentive for the generator to adhere to the notice period. This would ideally be tied to a proportion of the generating unit's past monthly revenue.

Such a regime is not a perfect remedy to the risk posed by an abrupt large power plant withdrawal. However, it would force the owners of these plants to be much more considered, cautious and transparent about how much longer they wish to operate their power plants. It would replace the current situation where owners face a one-sided option with limited cost and large potential upside from a wait-and-see strategy where they might seek to keep a plant hobbling along and obscure its durability in the hope another plant shuts down first, increasing wholesale prices and therefore plant revenue.

- **Commission an audit review of generators to assess their future viability every three years**

Rather than depending solely on plant operator's own statements to AEMO about when they believe their plant will operate, governments could commission a financial and engineering audit of all power stations greater than 20 years of age and over 500MW capacity.

Such an audit would assess both the financial and physical durability of these power plants and effectively stress test their ability to withstand likely future market conditions. In this respect, it would be not unlike the regulatory scrutiny applied to banks in light of the severe economic consequences that flow from the financial collapse of a bank. Such an audit could be undertaken by AEMO and the Australian Competition and Consumer Commission (ACCC) or the Australian Energy Regulator (AER) and the results would be provided to AEMO and the Australian Energy Market Commission (AEMC) to inform policy makers.

At the end of the audit process, Directors of coal-fired power plants would be asked to sign a public declaration that they believed their plant had a high probability of being able to continue to operate safely and reliably for the next three and half years given:

- A base set of market and regulatory conditions nominated by the ACCC/AER

- In addition if the directors felt these were not realistic they could also detail an alternative set of market and regulatory conditions that they believed were more likely to unfold which guided their belief that the plant could continue to operate safely and reliably for the next three and half years.

If directors did not believe the plant could operate safely and reliably, they would then be required to publicly nominate a new closure date.

- **Lock in nominated closure dates**

Another way to provide improved certainty around the timing of coal exits is for state governments to each legislate to lock in the coal-fired power plants existing nominated closure dates (provided to AEMO) and not allow operation beyond then. For example, as Eraring Power Station in NSW has a nominated closure date of 2032, it would not be allowed to operate beyond that date.

This should be treated a bare minimum, low regrets improvement over the current situation. Unfortunately, it doesn't address the risk that some coal-fired power plants are likely to close noticeably earlier than their current nominated closure date. However, it would provide a modest level of improvement in the investment environment for a new plant by putting some constraints around a potential worst-case scenario for such a plant which financiers can treat as backed by law.

It would also provide a clear signal that there will be a very large market opening up for projects that can firm-up supply from solar and wind – even if that market may be several years away. This has a good chance of spurring project development activity in the immediate term as these preparatory development costs are reasonably modest and the rewards from being a first mover in securing good sites can be high.

- **Introduce a regulated market mechanism for closure**

A more advanced and ambitious approach to simply locking in the current nominated closure dates would involve implementing a mechanism which regulates a structured coal capacity closure in line with state and federal governments' commitments to work towards a global effort to contain global warming ideally to 1.5 degrees and well below 2 degrees. Such a mechanism won't just help to achieve climate change goals, it can also help improve reliability by providing a means to inform market participants several years in advance about the timing of coal exist so that they have time to respond by building replacement capacity.

Various regulated market mechanisms have been suggested in Australia which attempt to provide a structure whereby a competitive process determines several years in advance which coal generating capacity will close. In some cases, this involves payments going to the generator which shuts, or generators being whittled out based on their willingness to pay for limited emission allowances or licences to generate a quantity of power. The key principles of such processes is that the power stations which are the most cost effective to close are encouraged to close earliest through the mechanism. This policy could be tied in with emission reductions targets or emission performance standards.

Examples of this mechanism which have been recommended in the Australian context include:

- **Jotzo and Mazouz model**: Payments are made by the industry as a whole to shut down the power stations which are most cost effective to close. [22] "Plants bid competitively over the payment they require for closure, the regulator chooses the most cost-effective bid, and payment for closure is

[22] Parliament of Australia. Final report: Retirement of coal fired power stations. 29 March 2017.

made by the remaining power stations in proportion to their carbon dioxide emissions."[23]

- **Blueprint Institute model**: "Announce sectoral emissions targets for 2026, 2028, and beyond 2030. Offer contracts across the three timeframes for emissions summing to the targets. Implement a sealed-bid auction system for allocating the contracts. Impose mutual obligations to affected workers upon expiry of the contracts. Accommodate a government funding allocation (positive, zero, or negative)."[24]

Learnings from Germany's auctions for closure can inform decisions around any regulated market mechanism for closure. In Germany, for anthracite (hard coal), the Coal Phase-Out Act proposed auctions for plant operators to remove capacity from the grid according to the government's schedule. In the auctions, coal generator operators tender capacity volumes to be taken offline, and how much money they require for the closure. There are maximum renumeration volumes per MW set for each round of auctions, which are set to decrease with each auction round (encouraging early participation in the scheme). After 2027, forced shutdowns will occur. [25,26]

The first auction of hard coal plants was oversubscribed. The total amount of compensation was 317 million euros. The scheme has been criticised for paying too much compensation to loss-making hard coal plants that are generating little electricity. Analysis by Ember found that nearly all the German hard coal fleet has been running at a loss since the end of 2018, collectively losing over 1 billion euros. Furthermore, the scheme aims for a 2038 final closure, however it should be aiming for 2030 to align with the Paris Agreement.[27]

A regulated market mechanism for closure would offer a clear closure schedule and path to zero carbon emissions. With coal exit dates publicly known and certain, private sector investors could then make investment decisions about building new supply with greater confidence. However, the payments could keep uneconomic, high emission assets in the system longer than expected as they are receiving payments which help them maintain profitability – as seen in Germany. Therefore, great care needs to be taken in its design.

- **Race to replace**

Another option is to link up the closure of ageing coal generators with the entry of new replacement capacity such that, for example, if replacement capacity is built then the ageing high emission generators are guaranteed to retire. For example, the government could specify that once 1000MW of dispatchable capacity (satisfying

[23] Frank Jotzo and Salim Mazouz, ANU. Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations. November 2015.
[24] Blueprint Institute. Phasing down gracefully. 2021.
[25] Clean Energy Wire. Spelling out the coal exit – Germany's phase-out plan. 3 July 2020.
[26] Library of Congress. Germany: Law on Phasing-Out Coal-Powered Energy by 2038 Enters into Force. 31 August 2020.
[27] Ember Climate. German State Awards €317 Million To Loss-Making Coal Plants. 8 December 2020.

specified criteria to ensure it was reliable) was built in a given location, then 1000MW of coal will be retired.

This would substantially improve investment certainty for entering generators but at the same time, new generators' remuneration would rely on outcomes in the electricity market rather than a government scheme or contract. This would mean the investors in these plants would carry most of the ongoing risks associated with the plant, thereby incentivising them to make well considered decisions about how to meet the market's long-term needs. Also, under such a regime, investors would have substantial freedom to decide which technology they felt was best to satisfy market needs in the absence of retiring coal (with a wide array of technologies likely to be able to meet criteria for being dispatchable and reliable).

The date of capacity withdrawal could be tied to entry of new capacity.

The "race to replace" concept could also be incorporated into a number of different policy mechanisms. For example, determining which coal generators would retire first might be determined through an auction along the lines of the Jotzo model, but the timing of retirement would be set by the speed at which new capacity was built rather than being set by government. It could also be integrated into contracts with individual coal plants controlling their exit such as the Victorian Government's contract with Yallourn (see section immediately following). In this particular instance, instead of the date of exit being specified as 2028 and no sooner, the date of capacity withdrawal could be tied to entry of new capacity.

If governments decided they did want to proceed with some kind of widespread support payment to prevent abrupt coal closure, as the ESB has proposed with their capacity payment, then the Race to Replace concept could minimise its negative distortionary effects in deterring new entry. This could be done by stipulating that if a generator wanted to opt into receiving a capacity support payment, they would have to agree to the condition that they could be randomly selected as the capacity to be withdrawn once new dispatchable capacity was built. This would have the added side benefit of ensuring that only generators which were genuinely at risk of withdrawing suddenly would receive availability support payments, thereby containing the cost to consumers.

- **Contract individually with generators**

Another mechanism which has been proposed and implemented by the Victorian Government with the Yallourn Power Station is a direct contract with an individual generator to close on a specified date. Such deals are highly problematic and should be seen as an absolute last resort only to be used in emergencies.

The ESB thankfully agreed with this view but proposed in its April Options paper to develop principles that states can follow when entering contracts with generators through an "orderly exit management contract."[28]

In the final recommendations to ministers, the ESB provided guidelines around how these contracts should be developed which include:

- "Where possible, jurisdictions should share with the market information about: … subject to confidentiality constraints, the nature of any arrangements reached in an Orderly Exit Management Contract that are relevant to the exiting generator's behaviour in the market"[29]

- "If jurisdictions are considering an Orderly Exit Management Contract in relation to a retiring generator:

  a) recovery of the costs of these arrangements should be funded by state governments, rather than the market, and should be kept separate to cost recovery arrangements in place for the RERT.

  b) the contract itself should include obligations on generators to:

     i. bid into the market and make the specified capacity / services available at the required times.

     ii. ii. ensure sufficient fuel is available and maintenance undertaken to meet output requirements until the end of the agreed term."[30]

While largely agreeing with these guidelines, we would suggest a range of additional requirements to minimise the distortionary effects of such agreements. In particular we note that the ESB's requirement under point "b (i)" above should not act to require the plant to generate any more than is absolutely necessary to ensure the reliable supply of electricity.

Further additional requirements detailed below are informed by the inadequacies and problems evident from the Victorian Government contract with EnergyAustralia for the closure of Yallourn. Under this contract, it was announced the power station would remain open until mid-2028 (several years earlier than the previously nominated date of a staged withdrawal from 2029 until 2032) and that EnergyAustralia would construct a 350MW battery with four hours duration by 2026.

It is important to be aware that signing this kind of deal is likely to encourage more deals of this type to be signed. As stated in ANU research, "Payments-for-closure

[28] Energy Security Board. Post-2025 Market Design Options A Paper for Consultation Part A. 30 April 2021.
[29] Energy Security Board. Post-2025 Market Design Final Advice to Energy Ministers Part B. 27 July 2021.
[30] Energy Security Board. Post-2025 Market Design Final Advice to Energy Ministers Part B. 27 July 2021.

schemes can lead to unhealthy expectations of future industry subsidies from government and therefore a deferral of plant closure decisions with associated emissions."[31] Under this agreement, up until the Yallourn closure, other coal plants will be at a financial disadvantage compared to Yallourn because they do not have a similar government mechanism to help them. In response, other coal plants may seek out the assistance of state or federal governments to ask for support like that which is provided in the Yallourn agreement, or they may close earlier than expected because they cannot compete with government-supported Yallourn or low cost renewables. The deal therefore could simply push the problem of premature exit onto another coal generator rather than actually resolve the risk.

Furthermore, ANU researchers noted, "The politics of paying significant sums of taxpayers' money to the owners of old, highly emissions intensive power stations would be highly problematic."[32] Alinta Energy, which closed its Flinders Coal Power Station and coal mine in South Australia in May 2016, argued that no government payments or incentives to close are required. It stated that the market 'understand[s] and price[s] the cost of closure into the long term planning', and ultimately the public purse should not pay for private closure."[33]

Thus, any kind of state government contract should only be adopted as an emergency measure if no more cost effective arrangements are available to achieve the reliability standard (0.002% or more unserved energy). It should only last until such a point in time where there are no longer any risks to reliability/price. If it is adopted, it should have strict conditions placed on it as outlined below. These need to have as an over-riding concern the need to not discourage the necessary investments in new replacement capacity as quickly as possible:

1. **The deal should only be entered into if there is no cheaper way to meet the reliability standard.**

   A contract with generators should only be entered into if it is the cheapest option to ensure that the reliability standard of 99.998% is met. Other options including the Reliability and Emergency Reserve Trader (RERT) and building distributed energy resources (DER) onsite should be examined and costed, and the cheapest option chosen.

2. **Deal should only be entered into if the generator cannot recoup costs through existing market and contractual arrangements.**

   Prior to entering into any exit contract, government should conduct a thorough financial and engineering audit (at the expense of the owner of the generator) to assess whether the asset is genuinely unviable. Such an audit, published publicly, should help to ensure that power stations are only assisted where absolutely necessary and give the public confidence about

[31] Frank Jotzo and Salim Mazouz, ANU. Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations. November 2015.
[32] Frank Jotzo and Salim Mazouz, ANU. Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations. November 2015.
[33] Parliament of Australia. Final report: Retirement of coal fired power stations. 29 March 2017.

the probity of these deals.[34] It will also help to inform government as to what level of payment is required in order to ensure required levels of availability from the plant, and would also potentially reveal severe physical faults with the plant. These would suggest that even with a support payment, the plant can no longer be relied upon for reliability purposes and government would be better off seeking alternative physical options for covering the power plant’s exit.

3. **Provision of the support payment should be delivered in such a way that the plant does not generate any more electricity than is absolutely necessary to ensure reliable supply.**

   It is vitally important that any managed exit support payment is not delivered as a production subsidy tied to the amount of electricity produced. The generator should instead be incentivised to not produce any more power than required to be able to respond to high demand periods. In the case of inflexible generators like Yallourn, this unfortunately means it will need to continue to generate power even during low demand periods like late at night or over sunny periods, otherwise it will be unable to ramp-up output during the late afternoon to satisfy the evening peak. However, the incentive should be provided in such a way that the operator is free to reduce output or even switch off completely during low demand periods or seasons (Autumn and Spring tend to be characterised by low demand) if this doesn’t undermine the plant’s ability to be able to ramp up output in high demand periods.

4. **Deal should act to increase investment certainty for replacement capacity, rather than reduce it.**

   The information that is currently known about the Yallourn contract is likely to deter the private sector from building replacement capacity to fill coal closure gaps earlier than 2028.

   a) If the agreement had a provision in place that allowed for earlier withdrawal of capacity if replacement capacity was in place (as detailed in the Race to Replace measure described above), this would encourage investment into replacement capacity. If the agreement does not have this provision, then the agreement in essence acts to deter rather than encourage new capacity. This is problematic because new capacity is likely to be lower emitting, and is also likely to be more reliable than an almost 50 year-old coal power plant on the verge of retirement that is highly inflexible.

[34] Typical claims that such audit results can not be published publicly due to the “commercial in confidence” issues are ridiculous given that the circumstance for such arrangements are that the owner of the plant has in essence conceded the plant is no longer a commercially viable ongoing entity. Such claims should be seen for what they are – an attempt to avoid scrutiny of expenditure of taxpayers money and hiding potentially embarrassing information.

b) Future contracts of this type should enable the coal generator to close earlier than expected if there is enough replacement capacity built such that reliability is likely to be maintained within the standard of 0.002% unserved energy ("USE"). For example, if there was enough supply coming online by 2026 such that Yallourn (or a number of Yallourn units) would be able to close with no risk to the 99.998% reliability standard in Victoria, then Yallourn (or a number of Yallourn units) should close in 2026. This would provide investment certainty for replacement capacity.

Based on reported comments by prior EnergyAustralia CEO Catherine Tanna, it appears is if the Yallourn contract is structured completely contrary to these characteristics. The *Australian Financial Review* reported on 15th March that, "Ms Tanna said a gradual shutdown didn't make commercial sense. EnergyAustralia has said the units will all operate until 2028 and close successively in the lead-up to June 30, 2028."[35] This is incredibly counter-productive to ensuring a smooth transition as Yallourn exits because any investor in a new plant has a very strong incentive to time their entry as close as possible to the 2028 exit date and no sooner. This is a potentially risky proposition for consumers given the new plant might suffer construction delays. It is also contrary to the condition we set out in point 3 and so while the risk of abrupt closure from Yallourn may have been contained, it has just shifted vulnerability and abrupt closure risk to another coal generator.

5. **The deal should be completely transparent to the wider market, consumers and taxpayers.**

Victoria's Energy Minister Lily D'Ambrosio has refused to disclose details of the Yallourn deal claiming they are *"commercial in confidence."*[36] Given the deal is premised on the very fact that Yallourn is no longer a commercially viable ongoing entity, such a claim is highly questionable.[37] Even if such a claim was justifiable, there is no reason why a range of important details about this contract couldn't be made public without revealing information that had commercial importance to EnergyAustralia beyond the operation of Yallourn.

The confidentiality of this deal is problematic for a range of reasons but of particular concern is that it leaves other market participants in the dark about how Yallourn is likely to operate over the period before its closure in 2028. For example, in spite of the comments made by former CEO Tanna (above), it may be the case that the contract does allow for and possibly even encourages the earlier withdrawal or mothballing of generating units if

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[35] AFR. Yallourn deal threatens other generators. 15 March 2021.
[36] Renew Economy. Victoria slammed for refusing to release details of secret Yallourn closure deal. 16 March 2021.
[37] Also, if a company wants government assistance, they must be prepared to accept they need to reveal commercially sensitive information necessary for effective public scrutiny to provide confidence that government is operating in society's best interests.

competing supply were plentiful. However, given no one really knows, it creates a level of unnecessary uncertainty that discourages both existing and new generators from making investments to fill the place of Yallourn. Even worse, it might precipitate another generator to exit the market abruptly if they expect Yallourn will continue to seek to maximise output.

If other deals of this type are agreed, in which state governments pay coal generators to continue operating up until a point in time, it is key that details of the deal be transparent to taxpayers and electricity market participants. This would include:

a. the operating conditions the plant must satisfy to qualify for payments

b. the structure and amount of the payments, and

c. the duration of payments

Ideally these should be all be publicly announced in advance of any contract being signed to allow for public scrutiny and feedback.

- **Regulate closures through emissions performance standards or other means**

Regulatory measures could be introduced that specify the emissions performance of power stations, or mandate the retirement of power stations based on specific emissions criteria. The Australian Parliamentary inquiry into the closure of coal generators suggested various ways this could be done.

"Direct regulatory responses could include:

1. introducing standards for the emissions performance of new or existing power stations, creating industry-wide standards;

2. facility-level absolute emissions baselines for high-emission generators (i.e. where each plant has a baseline for their total emissions that they must not exceed); and

3. mandated closure of power stations over time, on the basis of age or emissions intensity."[38]

In the UK emissions performance standards (EPS) were implemented in 2013. The standards set a limit on the emissions of new power plants at 450g CO2 -e per kW – similar to the emissions intensity of gas-fired generation, and approximately half the emissions intensity of a coal plant. The cost to comply with these regulations, and competition from renewables and gas, made new coal investments unviable. In 2015, the government announced that EPS would be extended to existing coal generators in 2025. This resulted in owners bringing forward planned coal plant

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[38] Parliament of Australia. Final report: Retirement of coal fired power stations. 29 March 2017.

closure dates, as the ageing coal generators were struggling to compete against renewables and gas, and had a clear date by which they needed to exit.[39]

Canada also implemented an emissions standard for new and existing coal-fired generators which meant that no new coal-fired power plants could be built without carbon capture and storage (CCS).[40]

Similarly, the U.S. adopted emissions standards for new coal generators which also effectively meant that no new coal generators could be built without CCS.[41]

The U.S. has also had substantial closures of coal capacity in the prior decade – 88,700MW between 2011 and 2021. While multiple factors have driven these retirements, the introduction of upgraded noxious EPS have played an important part in the timing of these decisions due to the necessity to often incur significant capital expenditure to comply. Because the application of these standards are flagged several years in advance and there is a widespread understanding of the emissions profile of coal generators (due to public disclosure of pollution levels), this has helped to provide market participants with advance notice of likely plant withdrawal.

This mechanism is likely to provide a clear schedule of closure for high emissions generation assets, enabling emissions reductions. This would increase confidence for investment in new replacement capacity.

It should be noted, however, that the Australian Energy Council has warned that "Regulatory closure, or even the requirement to give an extended closure notice, may prejudice both financing arrangements and supply contracts of power plants. This may then precipitate a disorderly closure if loans are called in early or suppliers terminate contracts. However, all of this depends on the type of regulatory closure."[42]

- **Market-based mechanism to reduce carbon emissions**

Emissions trading schemes don't directly act to regulate the timing of coal closure. Nonetheless, having such a scheme in place should give investors greater confidence to invest in new dispatchable plants knowing that even though they don't know the exact time that coal capacity will withdraw, the emissions constraint provides an enhanced degree of clarity that such coal withdrawals (or at least increases in bid prices) are likely and an approximate guide as to the scale and timing of those withdrawals.

This could provide a more orderly transition depending on the design of the market-based mechanism, and how it integrates with other electricity market policies.

[39] Blueprint Institute. Phasing down gracefully. 2021.
[40] Parliament of Australia. Final report: Retirement of coal fired power stations. 29 March 2017.
[41] Parliament of Australia. Final report: Retirement of coal fired power stations. 29 March 2017.
[42] Parliament of Australia. Final report: Retirement of coal fired power stations. 29 March 2017.

Ailment 2 – Market Contracting Behaviour Is Myopic

In the perfect world of an economic textbook, market participants would not encounter a sudden surprise exit of a coal generator creating a supply shortfall because they would contract for power many years into the future. In such a world, if the operator of a coal power plant came to the view that their power plant was unlikely to be viable a few years down the track, then this would be signalled to other participants through a rise in the price customers faced for power contracts in the years after the coal plant owner withdrew making offers to sell power. The price for purchasing power in forward markets could be expected to step up to a level that would make it profitable to build a brand-new plant. Prospective investors in a new plant would find plenty of customers willing to enter into a long-term contract at this price which would then enable them to finance and build the plant just as the old coal power plant was about to exit.

The ESB correctly points out that unlike our idealised textbook world, contracting by both customers and suppliers is heavily constrained in time ahead. This means there is limited pricing information available to investors to evaluate whether or not it makes sense to build a new plant or keep an existing plant going:

> *"Many of these large commercial and industrial customers – and an increasing number of retailers for residential customers – do not contract forward (which would drive investment in generation) but instead lower their costs by managing their energy price risk in the real time market because energy prices are low."*[43]

They later on emphasise this problem:

> *"a one-to-three-year focus by market participants on customer contracting behaviour, incentivises participants to manage their risk over the short rather than longer-term. It suggests an insufficient market incentive to manage long-term capacity risk. This leads to a disconnect between the risks faced by the market and those faced by governments on behalf of consumers. Consumers are therefore left bearing the risk of resource inadequacy due to a failure by the market to invest for the long term."*[44]

Compliance Under the ESB's Proposed Capacity Payment Mechanism Doesn't Encourage Longer Term Contracting

The ESB's proposed model for a capacity payment doesn't do anything to fix the issue around the market's short-term, myopic contracting behaviour. This is because their scheme will only involve assessing whether a retailer has purchased enough capacity credits after a shortfall in supply (or activation of the RERT) occurs. This means power retailers and large power consumers can continue to purchase on a short-term basis, it's just they'll be doing this for both energy and capacity credits.

[43] ESB. Post-2025 Market Design Final advice to Energy Ministers Part B. 27 July 2021.
[44] ESB. Post-2025 Market Design Final advice to Energy Ministers Part A. 27 July 2021.

This might work quite well for existing power plants if the supply of credits were to become tight or a power generator possessed market power in supply of capacity credits, because it will give the existing plants a top-up of additional revenue beyond that provided by energy sales. Given the plant is already built and only needs ongoing maintenance investment, this revenue top-up has the capability to extend an existing plants’ lifetime.

For new entrants however looking to invest substantial capital up-front to build a new plant such as battery, they really need long-term contracts to provide lenders with some assurance they will receive enough revenue to cover the loans. The current default model the ESB advocates will not provide this. The ESB actually concedes this fact (to a limited degree) but then provides no commitment that it will modify the capacity mechanism to ensure retailers offer longer term contracts for new capacity. Instead, it merely points out the problem and leaves this as an optional element for individual state governments to consider.

Alternative Options To Address Myopic Contracting

- **Government underwriting of the back-end of power project offtake agreements (ACCC)**

Government offtake agreements can be utilised to ensure that replacement capacity has certainty around revenue streams further into the future. The ACCC in its 2018 inquiry into the electricity retail market identified a similar problem as the ESB, noting that provision of long-term contracts were pivotal to the entry of new competitors in the electricity generating market, particularly those providing firm capacity, however large electricity consumers and small-scale retailers were unable or unwilling to enter into the length of contracts required to support financing of new generators. The ACCC noted that this represented a significant challenge for effective competition and sustained lower prices for consumers and to address this problem it recommended,

> *“The Australian Government should operate a program under which it will enter into low fixed-price (for example, $45–50/MWh) energy offtake agreements for the later years (say 6–15) of appropriate new generation projects which meet certain criteria. In doing so, project developers will be able to secure debt finance for projects where they do not have sufficient offtake commitments from C&I customers for later years of projects. This will encourage new entry, promote competition and to enable C&I customers to access low-cost new generation. The program should operate for at least a four-year period, with support provided for qualifying projects.”*[45]

Under this regime the ACCC set out several criteria that a project proposal must meet to qualify in order to ensure it was aligned with genuine customer needs and enhanced competition in the provision of firmed power supply:

[45] ACCC. Restoring electricity affordability & Australia's competitive advantage. 11 July 2018.

- have at least three customers who have committed to acquire energy from the project for at least the first five years of operation
- not involve any existing retail or wholesale market participant with a significant market share (say a share of 10% or more in any NEM region)
- be of sufficient capacity to serve the needs of a number of large customers
- be capable of providing a firm product so that it can meet the needs of commercial and industrial (C&I) customers."[46]

The advantage of ACCC's proposal was that rather than government determining what amount and type of new generating plant was required, it would be driven mainly by new entrant power suppliers signing up large electricity customers for electricity supply contracts, providing those customers with a product that insulated them from high prices in the wholesale market.

The disadvantage of such a measure is that in an environment of substantial excess generating capacity that would precede a coal closure, customers may still be relatively uninterested in the complexity of contracts likely to be required to induce new generating capacity. When this recommendation was made in 2018, wholesale power prices were very high which made direct contracting with new entrants or smaller power generators a viable option but interest in such arrangements has waned more recently.

Nonetheless this option is a far more direct and effective means of addressing myopic contracting behaviour than the ESB's capacity payment and is likely to be a useful option in the event that supply becomes tighter. Its' reliance on private sector contracting helps overcome some of the weaknesses with a number of the current government programs for supporting new firm capacity which depend heavily on government judgements about what type of capacity should be supported and how much.

- **Market Liquidity Obligation (MLO)**

The ACCC's 2018 Inquiry also recommended as a measure to make it easier for smaller new entrant generators and electricity retailers to compete that a market-making obligation be introduced (although limited to South Australia due to its particular problems with liquidity) which would require large, vertically integrated retailers to make offers to buy and sell electricity hedge contracts. A derivation of this recommendation was subsequently incorporated into the original Retailer Reliability Obligation (RRO) with the Market Liquidity Obligation (MLO). When the RRO is triggered into effect then large generators and energy users / retailers are required under the MLO to provide offers to buy and sell electricity hedging contracts three years ahead of the time when the RRO falls due.

To address the lack of longer term contracting, the MLO could become a permanent requirement operating independently of the RRO. In addition, the timeframe the

[46] ACCC. Restoring electricity affordability & Australia's competitive advantage. 11 July 2018.

offers need to be provided could be extended to say five years instead of three. This would result in more transparency around future prices and available supply. It should also help to flush out information that one or more coal generators were only willing to enter into supply agreements at relatively high prices, revealing to others that they didn't expect to be around in future years. This would then help to encourage the entry of new capacity that could offer capacity at lower cost and also provide them with a source of contracting demand for at least the first few years of the projects' operation.

- **Government underwriting mechanism**

Jurisdictional underwriting schemes, exemplified through the NSW Government Electricity Infrastructure Roadmap, are an effective means to make sure there is enough replacement capacity to fill any gap left by exiting coal generators. In the NSW Government scheme, a Consumer Trustee runs competitive tenders to offer Long Term Energy Service Agreements (LTESAs) for firming, long duration storage and generation. The LTESAs are options contracts that give the project access to a minimum price for their energy service.[47]

It is noted that jurisdictional underwriting arrangements like the NSW model may act to further reduce prices in the wholesale market in the medium term but once more coal generator closures occur, prices will likely rise again. A NEM-wide consistent approach to jurisdictional underwriting, which has been recommended by the ESB, could help the whole system align on the best way to build replacement capacity while indicative market pricing suggests ongoing real deflation in wholesale electricity prices (even against current record real lows).

- **Raising the market price cap**

Raising the market price cap is another initiative which could incentivise replacement capacity to be installed. A higher market price cap would also create the need for higher levels of contracting, as it would impose a higher cost on retailers that remain exposed to spot prices.[48] It also avoids the complexity, cost and risk associated with implementing a new, unproven market mechanism like the capacity mechanism. While it is likely to increase the level of contracting in the short term, it may not increase the level of contracting in the long term, as market participants can still contract on a short term basis to manage their exposure to the high market price cap.

Ailment 3 – Early Mover Disadvantage in Power Technologies Subject to Deflation

At present batteries and technology to remotely control electricity demand are characterised by significant ongoing cost reductions that are anticipated to continue for some time to come. Therefore, if someone were to invest in a battery power

[47] NSW Government. Electricity Infrastructure Roadmap. Accessed 18 September 2021.
[48] RenewEconomy. There's a better alternative to support the right mix of capacity and flexibility. 15 September 2021.

plant today, then in around five years' time they will find themselves in competition from a new entrant with a significantly lower cost structure. Given those circumstances, it makes good sense to hold back on such an investment unless they can earn a premium in the first few years to make up for poor returns in the future.

This is a problem in an electricity market with an energy-only structure, but there's no reason why they wouldn't face exactly the same problem with a capacity market (assuming batteries aren't cut out of the market via an unreasonable requirement for "long duration"). In both cases, if new batteries are the marginal supplier, they will set the price that all existing suppliers can earn, whether that be for a capacity credit or a megawatt-hour of electricity.

Alternative Options To Address First Mover Technology Deflation Disadvantage

The first mover deflation disadvantage issue is common not just to batteries but has also been a significant feature of both wind and solar power. To get around this problem, Germany pioneered the use of feed-in tariffs that awarded a fixed and long-term power price at the point a project was built, but with the price offered declining over time for future projects. The concept of experience curve deflation was consciously catered for in the design of the German mechanism. In many other countries, low carbon technology support mechanisms often failed to recognise and deliberately manage and encourage deflation. Yet, they nonetheless often landed on the idea of stepping down support levels over time, often by accident after budget blow-outs or because the schemes had short, legislated lives that were regularly reviewed and revised.

The main Australian support scheme for rooftop solar – the Small-scale Renewable Energy Scheme (SRES) - as an example has a regular and pre-announced annual step-down in the rate of support. South Australia has also catered for first mover deflation issues within its household battery rebate program, where the level of the rebate has been reduced over time.

In the case of the provision of utility-scale dispatchable power projects, the deflation issue could be addressed through two of the options detailed earlier to deal with myopic contracting behaviour. The NSW Government's Long Term Energy Service Agreements and the ACCC's proposal for the underwriting of the backend of offtake agreements would both provide investors with a base level of assured revenue that would not be eroded by deflation of battery and demand response technology, at least for the duration of the underwriting contract. At the same time, by employing rotating rounds of a competitive process such as an annual auction to award contracts, government and consumers can still continue to capture the benefits of deflation where the price paid to projects declines over time.

Ailment 4 – Unpredictable Government Intervention

It is undeniably true that state and federal governments have introduced an array of initiatives and policies that have supported, or will support the addition of substantial amounts of generation supply. Making things difficult for would-be investors in new power plants is that in a number of cases, these initiatives have been ad hoc, coming with little warning and without being tied to any kind of long-term policy frameworks or objectives. While these government initiatives have often been instrumental in supporting investment in generation capacity that are direct beneficiaries of the programs, investment outside these programs undertaken by the private sector on their own initiative and at their own risk is undermined.

The ESB's suggestion that these interventions stem largely from governments' concerns for reliability are highly questionable if not naïve. A capacity mechanism does nothing to address the real underlying reasons for why Australia's electricity market has been beset by ongoing and unpredictable government intervention.

State Government Initiatives a Product of the Lack of a Long-Term National Legal Framework for Emission Reductions, Not Reliability

Most state government interventions to date have been supporting the roll-out of renewable energy, prompted by goals to reduce greenhouse gas emissions associated with climate change. Ideally these would be rolled out under a long-term policy framework built on market principles that was more predictable for investors like the Renewable Energy Target or an emissions trading scheme of some kind. Unfortunately, clauses within the Federal Renewable Energy Act prevent states from implementing a similar measure. Meanwhile the governments of the NEM have failed to press ahead with implementing the emissions reduction component of the National Energy Guarantee. They also, rather strangely, refuse to implement an emission reduction objective within the National Electricity Law, even though they all have public commitments to net zero emission targets.

State Governments have also provided ad hoc grants to energy storage initiatives which do have a reliability or security objective but are in many respects a by-product of a longer-term goal of emission reductions by supporting the development of technologies important to transitioning the grid away from a reliance on fossil fuels.

The NSW Government's Electricity Infrastructure Roadmap is perhaps the first example of a policy framework that has advanced beyond short-term ad hoc interventions to put in place a long-term, more structured program for managing both emission reductions as well as reliability. This should certainly help improve predictability for private sector investors. However, because the Roadmap's scale of capacity roll-out is so large, it has to a large degree supplanted the role of the wholesale market's price signals in directing investment in new capacity.

Federal Government Measures More About Pork Barrelling Than Reliability

In terms of Federal Government initiatives, while they have often been justified publicly on the basis of reliability, they appear in reality targeted measures to improve electoral prospects in political seats considered at-risk. The purpose of this report is not to deliver a detailed inventory and review of all the dispatchable capacity projects that the Federal Government has elected to fund or underwrite, but to evaluate the degree to which they were a sound response to legitimate reliability issues. However, the examples below represent some of the most prominent commitments the government has announced, often with a strong public emphasis on the essential importance of "dispatchable power" which any reasonable assessment of the evidence suggests has very little to do with addressing the immediate needs to keep the lights on.

- **Tasmania's Battery of the Nation**

The Federal Government's commitment to underwrite Tasmania's Battery of the Nation Pumped Hydro initiative came in the months leading into the last Federal Election where two marginal Tasmanian seats (Bass and Braddon) were pivotal to forming government. In announcing the commitment to underwrite the project the government indicated it could be built and operating as soon as the mid 2020's.[49] Yet, analysis within AEMO's 2018 Integrated System Plan suggested the project was either not needed or would only be required around the mid 2030's or possibly even later.[50] AEMO's 2020 edition of the Integrated System Plan came to a similar conclusion.[51] Meanwhile the Marinus Link feasibility study funded by the Federal Government indicated it would not be needed until at least 7000MW of coal capacity had been shut down, which the Federal Government had never indicated it is preparing for.

- **Snowy Hydro's Kurri Kurri Power Plant**

The commitment to fund SnowyHydro's Kurri Kurri Gas-Diesel Power Station was announced just days before a NSW State byelection for the nearby seat of the Upper Hunter. In comments broadcast by ABC Radio, after the Nationals won the seat, Deputy Premier John Barilaro made no secret that this decision was important to their election victory.

Meanwhile, the Chair of the ESB Kerry Schott strongly criticised the decision stating that the project "didn't stack-up".[52] The Grattan Institute's Tony Wood observed that the plant was,

> *"not needed to maintain reliable electricity in NSW after the Liddell coal-fired plant closes in 2023. When the Australian Energy Market Operator published its Electricity Statement of Opportunities in mid-2020, it was clear that there would be no supply gap in NSW or the rest of the National Electricity Market for the remainder of this decade."*[53]

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[49] Prime Minister of Australia. Doorstop – Lake Cethana, Tasmania. 27 February 2019.
[50] AEMO. 2018 Integrated System Plan. 2018.
[51] AEMO. 2020 Integrated System Plan. 2020.
[52] The Guardian. Australian energy board chair says gas-fired power plant in Hunter Valley 'doesn't stack up'. 30 April 2021.
[53] The Grattan Institute. Gas misfire: the Federal Government's $600m intervention in the energy market. 19 May 2021.

- **Feasibility study for northern Queensland coal or pumped hydro power project**

During the 2019 Federal Election where central and north Queensland swinging seats were central to the campaign, the Federal Government announced it would allocate $10 million towards a Supporting Reliable Energy Infrastructure Program that would look to provide support for assessing the feasibility of a power station in the region. At the time the Deputy Prime Minister Barnaby Joyce, Resources Minister Matthew Canavan and Townsville MP George Christensen implied in public comments that this represented a commitment to build a coal-fired power station in northern Queensland.[54]

However, AEMO's Electricity Statement of Opportunities (ESOO) has indicated in both the 2018 ESOO and the 2021 ESOO that Queensland's supply of power is more than adequate to ensure high levels of reliability.[55][56] The AEMO 2018 Integrated System Plans also indicates that the transmission system has inadequate capacity to accommodate the amount of power one would expect from the type of coal-fired power plant they have in mind at its minimum economic scale (ultrasupercritical pressure – also inappropriately branded as HELE) due to constraints in between Townsville and Rockhampton.[57]

Alternative Options To Address Ad Hoc Government Intervention

We sympathise with the ESB's difficult position in this area; they tried to implement an emissions control measure via the National Energy Guarantee which was ultimately fruitless. They also need to constructively work with a Federal Government that has not acknowledged the inarguable need for a binding long-term legal framework for reducing emissions in the electricity sector. On the other side, there are state ministers with ambitious plans for the roll-out of renewable energy and emission reductions who have been reluctant to acknowledge the reality that this also means coal-fired power stations will need to close.

A capacity market however will not cover over the negative side effects of the ongoing political conflict over climate change policy.

The ESB is meant to be an independent advisory body that provides public advice in the best long-term interests of consumers. It should not resile from this role even if the advice it provides is uncomfortable for the Ministers it reports to. Until a long-term, legal framework to drive significant emission reductions is implemented across the NEM, the shadow of climate change will overhang the market creating doubt and uncertainty for investors. Unfortunately overlaying on top of this, the

[54] The Conversation. Morrison kicks decision on Queensland coal plant well down the road. 26 March 2019.
[55] AEMO. Electricity Statement of Opportunities. August 2018.
[56] AEMO. 2021 Electricity Statement of Opportunities. August 2021.
[57] AEMO. 2018 Integrated System Plan. 2018.

prospect of a capacity market just makes the uncertainty for investors in projects that could fill the gap from closing coal even worse.

Instead, the ESB must persist with pointing out the uncomfortable truth to ministers that they must back their promises for net zero emissions with laws to make it a reality over the long-term. These will be more easily and efficiently achieved if done on a NEM-wide basis. In addition, Ministers have to acknowledge the fact that coal power plants will have to close, rather than developing ways to disguise or forestall this potentially tricky political outcome.

Several of the alternative options to a capacity market which are outlined in this report will help with both:

- reducing greenhouse gas emissions; and
- enhancing the likelihood of coal being replaced on a timely basis that should help to maintain reliability and minimise disruptive price spikes.

In that respect they should help to significant degree in countering politicians' temptation to intervene in an unpredictable basis. But some of the more important reforms will also require our political leaders to have more honest and difficult conversations with communities where coal fired power stations are an important source of income. This is unavoidable.

Options To Add a Short-term Buffer for Reliability and Security

In lieu of achieving a long term, sensible integration of both climate change and energy policy, it is fair to say that that energy market participants and government officials face a potentially bumpy and uncertain road. While it would be unwise to institute a market-wide and long-term capacity payment, there may be some merit in putting in place measures that would provide a greater buffer in our electricity system, at least over the short term until the Snowy 2.0 upgrade and associated transmission comes online.

While there is plenty of dispatchable capacity coming online in advance of coal power plant closures as currently scheduled,[58] there is a short-term risk to reliability which flows from the fact that an abrupt *unplanned* coal power plant closure (or significant coal capacity withdrawal across several plants) is reasonably likely by 2025,[59] prior to when the Snowy 2.0 project is scheduled to be complete in 2026. Further risk to reliability could arise if the construction of Snowy 2.0 or associated supporting transmission upgrades were delayed. Something which is reasonably likely given the Federal Government has failed to ensure transmission capacity commitments were co-ordinated in alignment with, and at the same time as, commitment to the Snowy 2.0 upgrade. At present the supporting transmission lines to Sydney and Melbourne are yet to receive Australian Energy Regulator

[58] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[59] IEEFA. Fast Erosion of Coal Plant Profits in the NEM. February 2021.

approval. They could also encounter community opposition and therefore potentially delays in obtaining planning and environmental approvals.

Unfortunately, while the Snowy 2.0 upgrade will certainly play a useful role in the event of coal closures, its huge size has almost undoubtedly acted to crowd out alternative dispatchable plant investments from the private sector. These would have likely involved smaller projects involving technologies and sites that had far lower risks around delivery timing due to:

1. faster and less complex construction than Snowy 2.0's extensive underground tunnelling; and

2. voiding the need for major new transmission lines with their associated multi-year regulatory approval processes.

Snowy's huge size but long lead time has effectively created a temporary no man's land between 2023 to 2026 where coal plant withdrawal is reasonably likely but replacement dispatchable plant is unlikely to be forthcoming outside of direct government inducement (which is what was necessary for Tallawarra B to proceed).

The ESB's capacity payment proposal doesn't really help with this issue because it can't realistically be implemented prior to 2025. This indicates some kind of reliability buffer could be helpful in the short term.

There are multiple options which do not directly address the issues of coal exit uncertainty or short term contracting, but which could provide a type of structured market-based buffer that would allow the electricity system to be more resilient in the event of abrupt coal plant withdrawal or severe breakdown. The ESB has proposed two of these: the operating reserve and the strategic reserve. Both will add a reliability and security buffer, although we would caution that while there is a case at least in the short-term for a buffer, benefits need to be evaluated relative to their extra cost.

- **Operating Reserve (ESB recommendation)**

The ESB proposes to create a market for reserve services, in the form of an operating reserve. This could provide an explicit value for flexible capacity to be available to meet required net demand ramps.

The AEMC has outlined characteristics that would be required by reserves including:

- Ramping capability

- Reserve capacity.[60]

At present, AEMO has "in-market" reserves in the form of capacity which has been offered into the market but not dispatched. However, this is not explicitly valued or

[60] Abi Prakash, UNSW – for Watt Clarity. Let's Talk About (Operating) Reserves. 28 July 2021.

paid. Paying those reserves through an operating reserve service would be a major change to the NEM.

UNSW research has stated that "operating reserves are typically procured from dispatchable generation (i.e. coal, gas, hydro) and storage. However, within the limits of their energy source availability, wind and solar can be operated in a flexible manner and could also provide reserves."[61]

The operating reserve would provide additional revenue for certain generators. UNSW has stated that "valuing reserves (through something like an operating reserve demand curve) can act as a "price-adder.""[62]

The other side of the coin, as UNSW notes, is that consumers will bear the cost of the operating reserve, and the cost benefit analysis has not yet been completed to determine if this is an efficient mechanism. "More analysis is required to justify implementing an operating reserve service, particularly as consumers will likely bear the costs."[63]

- **Strategic Reserve**

The ESB proposes to create a "Jurisdictional Strategic Reserve (JSR)" i.e. a strategic reserve held on state-by-state basis.

In a strategic reserve, additional capacity is contracted (usually by the system operator) and held in reserve outside the market and only operated under specific scarcity conditions.[64] The strategic reserve provides a buffer that can be drawn upon to maintain reliability.

The NEM already has a NEM-wide strategic reserve in the form of the RERT. The ESB JSR proposal will create a similar mechanism but for the states.

> *"A JSR would facilitate the procurement of any required reserves additional beyond the market reliability standard that jurisdictions consider necessary, in a manner which is targeted and least distortionary to current market arrangements. The jurisdiction would be responsible for determining the level of reserve that it considers appropriate and for establishing the reserve. The JSR would then become part of AEMO's RERT portfolio and would be activated as needed. Costs of the reserve, once activated, would be recovered in a manner consistent with the existing cost recovery arrangement for the current RERT."*
> *- ESB[65]*

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[61] Abi Prakash, UNSW – for Watt Clarity. Let's Talk About (Operating) Reserves. 28 July 2021.
[62] Abi Prakash, UNSW – for Watt Clarity. Let's Talk About (Operating) Reserves. 28 July 2021.
[63] Abi Prakash, UNSW – for Watt Clarity. Let's Talk About (Operating) Reserves. 28 July 2021.
[64] AEMC. Profiling the capacity market debate. Accessed 10 September 2021.
[65] Energy Security Board. Post-2025 Market Design Final advice to Energy Ministers Part A. 27 July 2021.

The potential combination of an operating reserve and a strategic reserve would provide two buffers for resource adequacy concerns and the operating reserve will also help manage grid security on a shorter timeframe.

Conclusion

Many options exist to address the NEM's high levels of uncertainty around coal exits, myopic market contracting behaviour, early mover disadvantage in power technologies subject to deflation, and unpredictable government intervention. These options should be assessed as they are likely to be lower cost, more effective in dealing with diagnosed ailments, and more likely to drive the NEM to a low emissions future than the capacity mechanism proposal.

An additional payment to existing generators in the form of a capacity mechanism will not adequate address the ailments facing the NEM.

A financial lifeline to aging thermal power plants leaves the NEM reliant on supply that will become increasingly unreliable, and exacerbates uncertainty about when coal plants may exit. This uncertainty will deter investment in newer, more flexible and more reliable power plants.

A capacity market will not encourage longer term contracting as the scheme will only involve assessing whether a retailer has purchased enough capacity credits after a shortfall in supply (or activation of the RERT) occurs. This means power retailers and large power consumers will continue to purchase on a short-term basis, but for both energy and capacity credits.

The proposed capacity market does nothing to rectify the disadvantage for early movers as the ongoing cost deflation still exists and would impact both the capacity market and energy market, rather than just the energy market. In both cases, if new batteries are the marginal supplier they will set the price that all existing suppliers can earn, whether that be for a capacity credit or a megawatt-hour of electricity.

A capacity market will not fix the underlying issues which are driving government intervention – which is the lack of a national emissions reduction framework and the incentive to pork barrel.

A capacity market will also reduce the ability of the NEM to reduce emissions as it involves a payment mainly to existing fossil fuel generators.

Energy Ministers should *not* agree to a capacity market.

Instead we would suggest that they further investigate other potential options detailed in this paper which could be more effective in dealing with diagnosed challenges, involve less cost to consumers, and also assist in driving the NEM to net-zero emissions, consistent with state government targets.

Such an investigation would be best undertaken by an independent panel of internationally recognised experts in:

- energy market operation and design from both an engineering and economic perspective;

- decarbonisation of energy systems; and

- current and future energy technologies.

Unlike the ESB, these individuals should not be not be dependent on ministers for their ongoing employment. This will ensure recommendations are not distorted by short-term political pressures and do not obscure or pass over uncomfortable but important challenges society must grapple with as we seek an electricity system which delivers reliable, affordable and ultimately zero emission power.

Appendix – Further Detail on the Need for Short Versus Long Duration Resources With the Exit of Fossil Fuel Plant

As touched upon earlier in this report, while the ESB paper suggests that entry of new battery and demand response capacity will be encouraged by their proposed capacity payment, comments made by Minister Angus Taylor and referencing the ESB suggest the capacity mechanism will heavily favour "long duration" resources. This is an extremely significant consequence because it could represent a subtle but very decisive way to design a capacity market that was inappropriately biased against new entrants in favour of the current incumbent coal, gas and hydro generators.

At present the ESB has provided extremely limited detail around how it will treat duration of capacity response in its capacity payment, and no definition of what "long duration" storage happens to be. However, using AEMO's 2020 Integrated System Plan they define three categories of storage:

- short (less than 2 hours)
- medium (between 4 to 12 hours)
- deep storage (24 hours or longer).

From this we interpret that long duration is likely to mean that a battery or demand response would need to deliver a megawatt of capacity for 12 continuous hours or longer in order to qualify for a capacity credit.

As stated earlier in this paper, batteries and demand response technologies are currently highly competitive at delivering capacity very quickly for relatively short durations of less than 2 hours and soon 4 hours. Given likely cost reductions, batteries in particular should reach the point of being the best choice for applications requiring 6 hours of service. However, it seems unlikely that batteries could manage to reach cost competitiveness over a 12 hour duration for some time to come.

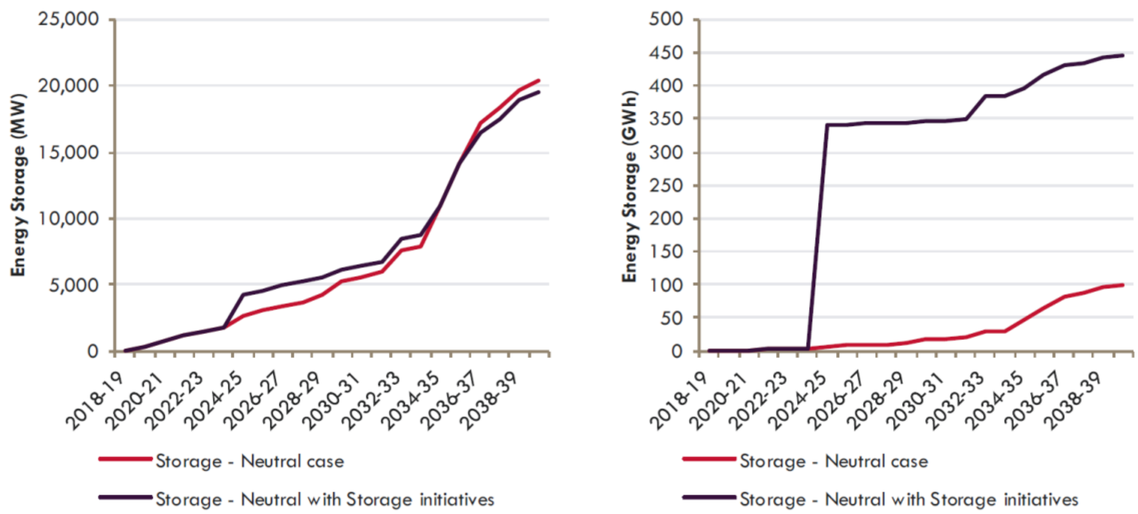
Having said that, batteries and demand response don't need to sustain a megawatt of capacity over such a length of time to make an extremely useful contribution to reliability as coal exits. The main challenge we face for reliability over the next decade and a half as coal exits is managing quite a narrow window of time between when solar output drops away at around 3pm until 9pm, a period over which demand for power remains high.[66] This is a 6-hour window, not 12 hours plus.

A sensitivity analysis AEMO undertook for the 2018 edition of its Integrated System Plan helps to illustrate that while we will need more storage plant megawatts, most of it won't be needed for long periods of time.[67] This sensitivity analysis examined energy storage needs based on the least cost options (the scenario denoted as the neutral case), and then an alternative sensitivity that shoehorned Snowy 2.0 and Tasmania's Battery of the Nation (BoN) pumped hydro plants into the mix, irrespective of system needs and economics. This involved Snowy 2.0 entering in 2024-25 and Tasmania's BoN in 2032-33.

Figure 1 details on the left-hand side the peak instant capacity in megawatts that energy storage would provide under both sensitivities and the result is similar across each of them. This is the maximum amount of power that could be delivered to the grid at a single instant point in time. Where the big difference arises between the two sensitivities is for how long that power could be delivered, with the right hand chart showing the amount of energy capable of being kept in storage. The dark purple line shows a huge spike upwards in energy stored when Snowy 2.0 comes online in 2024-25 and then another, but far smaller, upward spike in 2032-33. By the end of the outlook, the model's least cost path shown in the red line has 100GWh of storage while the one that forces in Snowy 2.0 and BoN has four and half times that amount.

[66] IEEFA. Fast Erosion of Coal Plant Profits in the NEM. February 2021.
[67] AEMO. 2018 Integrated System Plan. 2018.

Figure 1: Energy Storage Peak Delivery Capacity (MW) and Energy Capacity (GWh) Under Economically Optimal Case and Case Including Snowy 2.0 and Tasmania Battery of the Nation



Source: AEMO Integrated System Plan – 2018.

If we look at the model's least cost path it involves 20,000MW of peak capacity with 100GWh of energy storage, which equates to just 5 hours average duration.

Admittedly, this case was for a scenario where emission reductions unfolded relatively gradually, but it still represents a supply mix at the end of the projection with vastly greater renewables than at present (75% of electricity supply compared to about 30% today) and one where 14,000MW of our current coal capacity had been shut. So it illustrates that there isn't any immediate strong case for a capacity market biased to induce long-duration resources

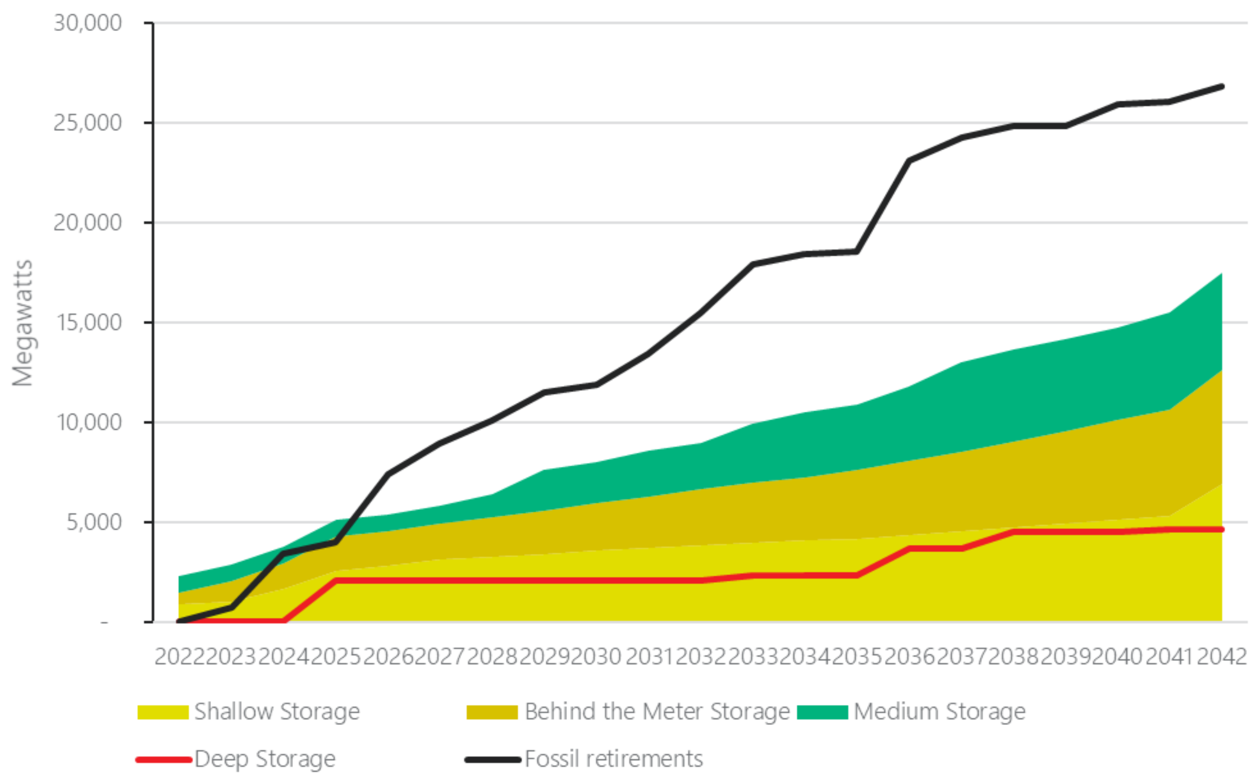
Unfortunately, AEMO's more recent 2020 Integrated System Plan only provides quite broad breakdowns on the nature of the storage that is installed under each of its scenarios with no quantification on the precise GWh of energy storage. Nonetheless, the data which is published also strongly suggests substantial coal closures can be accommodated predominately through an expansion in batteries providing around 6 hours duration or less, with not much long duration storage required for the next decade and half beyond that already provided by Snowy 2.0. In the data AEMO provide they break down energy storage installations by whether they are:

- short duration (2 hours or less),
- deep (24 hours or longer),
- medium duration (anywhere between 4 hours to 12 hours); or

- behind-the-meter (these can effectively be categorised as short duration style batteries although owners may discharge them on average over many hours per day).

Figure 2 illustrates the different types of storage AEMO envisaged would be required over time under its Step Change Scenario – the scenario with the most rapid fossil fuel plant closures. The medium and short duration storage are detailed in the yellow and green stacked area while the deep storage is shown separately in the red line. The figure also shows the cumulative amount of fossil fuel capacity shut in the black line. According to AEMO's analysis there was no need for any significant additional deep storage beyond Snowy 2.0 (represented by lift in the red line that happens in 2025) until 2035. Indeed, the amount of medium duration storage capacity required is also quite modest up until 2032 at less than 2,500MW. Meanwhile a very large amount of fossil fuel capacity is shut over the same timeframe.

Figure 2: Megawatts of Fossil Fuel Plant Retired and Different Duration Storage Installed in AEMO's Step Change Scenario



Source: Generation data for Step Change Scenario in AEMO Integrated System Plan – 2020.

Admittedly the medium duration storage category covers durations that extend beyond what batteries are considered capable of providing on a cost-competitive basis for the next decade or so. However, an examination of the amount of annual generation AEMO expects medium duration storage to provide suggests an average duration of about 4 hours in 2030 which then extends to about 6 hours by 2042[68] - well short of anything that might justify a requirement that capacity credits only be awarded to plants capable of meeting a long duration requirement.

Given the analysis above, if capacity credits are heavily skewed in favour of power plants capable of delivering megawatts over long durations it suggests a market that is not really designed for what is actually needed by consumers. Instead it would seem to be a market designed to support the dominant incumbent generators, while cutting out competition from alternative, new entrant firming from batteries and demand response.

[68] In 2030 the peak megawatt capacity of medium duration storage is 2,015MW which is expected to generate 8,470MWh on average per day. This equates to full output for 4.2 hours. By the end of the projection in 2042 there is 4,880MW of medium duration storage which is expected to generate 25,304MWh on average per day. This equates to full output for 6.2 hours.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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