



Energy Security Board's Capacity Payment: Burden on Households

Capacity Payment Primarily to Fossil Fuel Generators Could Be More Than Double the Cost of the Carbon Price

Summary

With the backing of the Federal Energy Minister Angus Taylor, the Energy Security Board (ESB) has proposed a dramatic change to how the east coast electricity market (the National Electricity Market or NEM) will function. As far as we are aware, this proposal for a capacity payment comes without any economic analysis detailing the cost of this regulatory change, why this extra cost is necessary or why it is preferred compared to alternative options.

The ESB's proposal will require consumers, via their retailer, to provide a large payment primarily to conventional power plants (mainly coal and gas power plants) based on the installed capacity of their generators, irrespective of how often that capacity is needed to generate electricity. By comparison, at present, generators are only paid based on actual electricity generated.

Our analysis, based on experience from the Western Australian electricity market, shows the capacity payment could be in the realm of \$2.9 billion to \$6.9 billion each year. This would result in an average cost of \$182 to \$430 per household per year.

This is a massive additional cost, which could be more than double the impact of the carbon price on a household electricity bill. It will come without any compensating reduction in the energy market price cap or generator bidding controls based on what appears to be recommended in the ESB Post 2025 Market Design Options released in April.¹

According to the ESB and Minister Taylor, consumers need to provide this new capacity payment to generators to ensure sufficient supply to meet demand, otherwise power blackouts will occur.²

¹ Energy Security Board. [Post 2025 Market Design Options – A paper for consultation Part A](#). 30 April 2021. Energy Security Board. [Post 2025 Market Design Options – A paper for consultation Part B](#). 30 April 2021.

² The Hon Angus Taylor MP. [Remarks at the 2021 Australian Energy Week Conference](#). 25 May 2021.

However, quantitative analysis indicates that supply is more than adequate to meet demand even if another major coal generator (beyond Liddell) is closed early.

Meanwhile, as the NEM experiences increasing levels of wind and solar in the generation mix, and increasing numbers of battery installations and demand response, it is increasingly important that price signals adjust very quickly to reflect a supply-demand balance that is changing on a shorter timeframe than seen in the past.

A capacity payment is a backward step that will not allow for the increasing levels of flexibility needed in the power system. It requires a central planner to guess the power system's capacity requirements a year or more in advance, and fails to adequately recognise the large diversity in how quickly technologies can respond to changes in demand. This makes the system more rigid rather than encouraging flexibility. There is a range of reforms that have been or are about to be implemented, which address short time-frame issues around system security and will allow for the increasing flexibility seen in the NEM. The capacity payment is not one of them.

Most stakeholders representing electricity consumers, retailers and renewable energy generators do not support a capacity payment, understanding it is unnecessary. Instead, support is principally from the owners of coal-fired generators.

The reality is that coal-fired power stations are exiting power systems across much of the developed world at a very large scale without harming reliability. This is a necessary outcome for countries to meet the Paris Climate Change Agreement to contain global warming to well below 2 degrees above pre-industrial levels, and preferably to 1.5 degrees.

The problem is not that coal power plants will exit, but rather that they might exit abruptly without providing enough notice for investors to respond by building replacement capacity. However, the likelihood of abrupt exit is contained and manageable, as there is an influx of dispatchable generation coming online to replace coal. Almost 6,500MW of new dispatchable capacity is due to be added to the NEM between 2017 and 2027. This is 1.9 times the aggregated capacity of the coal power stations – Yallourn, Callide B and Vales Point B – scheduled to close soon after 2027. Any residual risk of abrupt closure could be reduced with better regulation, that is more targeted and addresses the uncertainty around coal closure directly, rather than through a generalised payment to all fossil fuel and hydro generators in the NEM.

An additional payment to existing generators in the NEM risks locking the old legacy system in place for longer, which may in fact harm reliability. A financial lifeline to these aging power plants leaves us reliant on supply that will become increasingly unreliable, while exacerbating uncertainty about when they may exit. This uncertainty will deter investment in newer, more flexible and more reliable power plants that make better sense into the future.

Instead of consumers paying extra money to owners of coal generators via capacity payments, the ESB needs to undertake a more thorough evaluation of lower cost

alternatives for managing the risks of supply adequacy as coal power plants exit, of which there are several.

It is important that any reform options, particularly ones involving a substantial new cost to consumers, are evaluated based on a thorough, evidence-driven assessment of the problems the market faces. This includes carbon emissions and proper consideration of all available options. We need to avoid a rushed approach that could be driven by threats of certain commercial interests facing financial difficulties, or short-term political motivations.

The Cost of Capacity Payments Will Be Large

Neither the ESB nor Federal Energy Minister Angus Taylor have provided any quantitative assessment of the likely cost of paying power plants based on their installed capacity, in addition to paying them for their energy.

However, in the Western Australian electricity market, the capacity payment each year is considerable, ranging from a low of \$78,573/MW to a high of \$186,001/MW.³ Such a payment to cover the NEM's forecast 2022/23 1 in 2 year (POE50) peak in demand of 37,161MW⁴ would entail capacity payments of between \$2.9 billion and \$6.9 billion per year.

This would result in an annual average cost per household on their power bill of \$182 to \$430.

To put this into context, the below illustrates how this compares to the extra cost added to household power bills by the carbon price according to the Australian Competition and Consumer Commission (ACCC). In New South Wales' (NSW) households, the capacity payment would exceed the impact of the carbon price by 41% to 234%. For Victoria, it would be 62% to 284% greater, while for Queensland, it would be 21% to 187% greater. Note that unlike the carbon price where revenue went to the government, this change would come without any compensating reductions in income tax.

Minister Taylor appears to suggest the capacity payment will simply be overlaid on the existing energy market,⁵ so there will be no change to the NEM's energy market price cap of \$15,000/MWh, the highest in the world, nor other constraints applied to generator's bidding practices. By comparison in WA (and other markets with capacity payments), consumers get compensating benefits, as the price cap is below \$600/MWh, and generators are constrained from bidding above their operating costs.

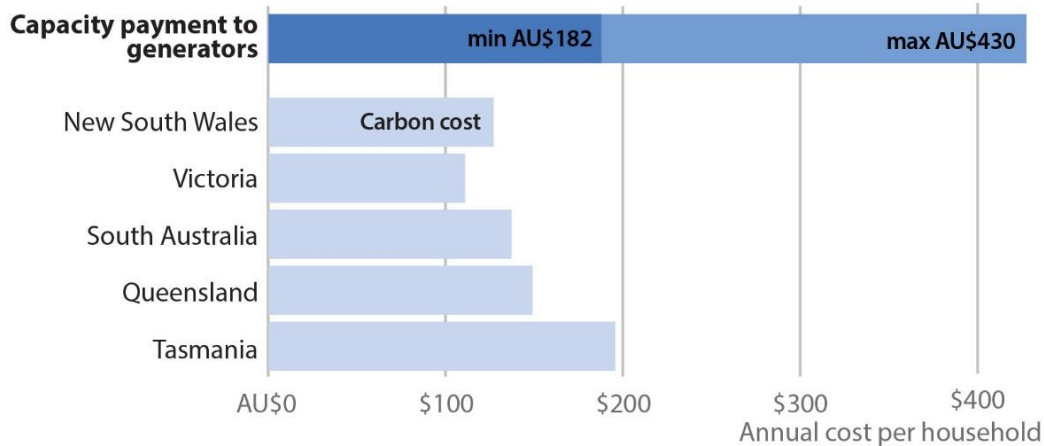
³ AEMO. [Reserve Capacity Price](#). Accessed 11 August 2021.

⁴ AEMO. [ESOO 2020 Electricity Annual Consumption](#). 27 August 2020.

⁵ The Hon Angus Taylor MP. [Remarks at the 2021 Australian Energy Week Conference](#). 25 May 2021.

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Capacity payment primarily to fossil fuel generators could be more than double the impact of the carbon price



Source: IEEFA Analysis based on data from AEMO, AEMC, AER, ACCC

IEEFA

We Should Not Panic About Reliability

While the Federal Government has promoted the idea that we face severe and immediate risks of power outages from insufficient dispatchable generation,⁶ the reality is that peak demand is barely growing, and the NEM is about to experience not just a large influx of variable wind and solar but also dispatchable capacity.

This multi-billion dollar new annual capacity payment to generators from consumers is being justified based on concerns that coal generators in particular “are going broke” and that if they were to close, reliability of the power system would be threatened due to inadequate dispatchable capacity (capacity that can be turned up and down based on fuel supplies independent of short-term weather patterns). The new capacity payment will therefore be expected to improve the financial viability of coal generators, making their withdrawal less likely. On the counter side, it is also being justified as necessary because it encourages investment in new dispatchable capacity that will help replace the coal power plants, even though the payment is also intended to make these coal power plants much less likely to close.

A prior analysis we conducted indicates that several coal generators' financial viability is under threat.⁷ A continued heavy dependence on such large individual power plants when their future reliable operation is subject to severe uncertainty is problematic.

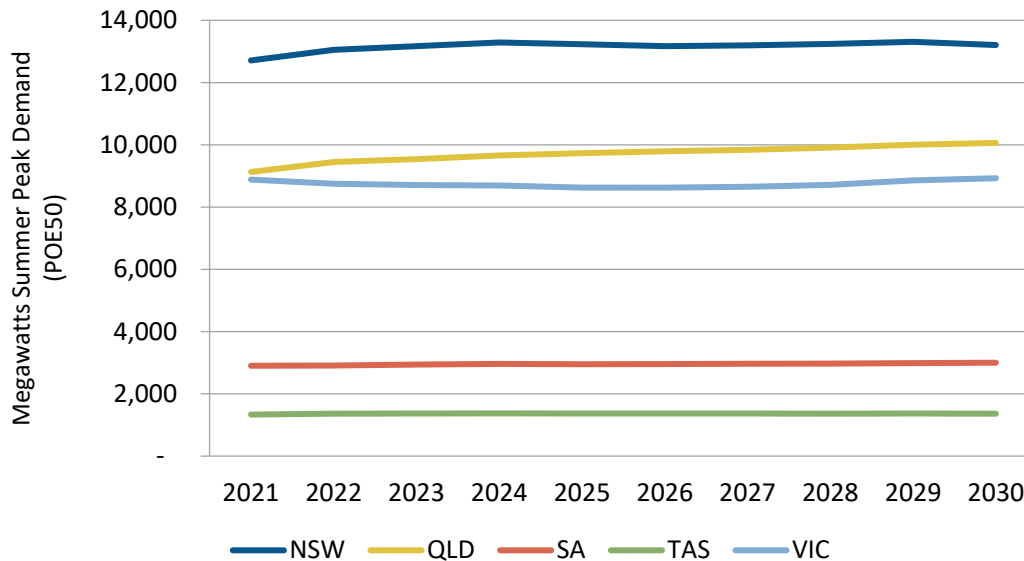
However, dealing with this problem is manageable through effective, low cost, targeted measures, rather than a complete wide-scale change to the market

⁶ Ibid.

⁷ IEEFA. [Fast Erosion of Coal Plant Profits in the National Electricity Market](#). February 2021.

involving a new, perpetual multi-billion dollar annual payment given to primarily conventional generators.

Projected Peak Demand by State 2021-2030



Analysis detailed below shows there is, in fact a substantial amount of dispatchable capacity entering the system, which could cover several coal exits.

Once this problem is put in its proper perspective, the available evidence suggests that the withdrawal of these coal power plants can be successfully managed while maintaining high levels of reliability at a much lower cost than introducing a capacity payment.

The Likelihood of Abrupt Coal Exit Is Contained and Manageable

The prior analysis we released in February found that an influx of renewable energy will mean five coal generators would lose money by 2025 if there were no further withdrawals of generator capacity beyond Liddell.⁸

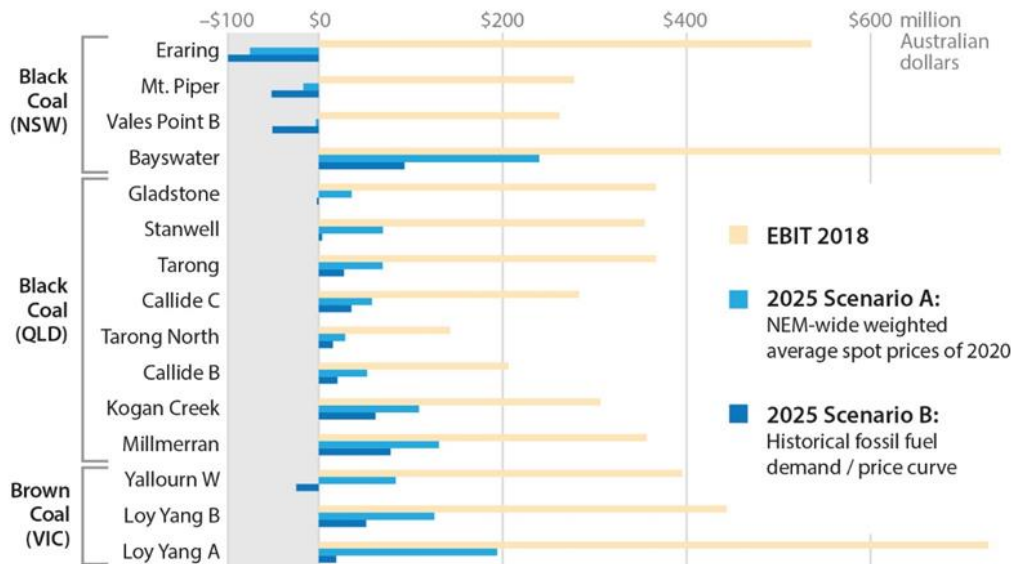
While this makes the exit of one of the coal power plants highly likely (or sub-units of several coal power plants), the withdrawal of this capacity would reflate prices and increase sales volumes for the remaining plants. This would then substantially reduce the likelihood of further exits. Therefore, while we face heightened risks of coal capacity exits that should be taken seriously, an unmanageable, mass exodus of capacity within a short period of time is not credible.

⁸ IEEFA and GEM. *Fast Erosion of Coal Plant Profits in the National Electricity Market*. February 2021.

Furthermore, it is important to note that owners of these plants are legally obliged to provide regulators with at least 42 months' notice of closure of capacity. If this amount of notice is provided, then it should give sufficient lead time for other businesses to build replacement capacity if it is required.

Coal Plant Profitability is Declining

All coal plants are projected to have substantially lower 2025 EBIT. Under Scenario A, three plants will have negative 2025 EBIT while Scenario B indicates five plants would have negative EBIT.



Source: IEEFA analysis based off AEMO data and Green Energy Markets forecast

IEEFA

The problem is not so much that coal power plant capacity is likely to be withdrawn; if Federal and State Governments are to honour their climate change commitments this is inevitable. Rather, the problem is that this withdrawal may occur with inadequate warning and therefore insufficient time to replace the exiting plant with new plant necessary to maintain reliability and affordability.

Unfortunately, the obligation to provide 42 months' notice as currently structured is unlikely to be effective in ensuring all operators provide plenty of notice before withdrawing capacity.⁹ There are loopholes in the rules and financial penalties are unlikely to deter non-compliance in an event where a company is losing money anyway.

However, this doesn't mean we should give up on requiring owners to operate such critical assets responsibly. Nor does it mean we must instead pay them extra money to restore their profitability so they no longer wish to close the plant.

It is important to recognise that not all operators of at-risk coal power plants are likely to completely disregard their obligations to provide 42 months' notice of capacity withdrawal. This narrows down the extent of risk for abrupt withdrawals

⁹ IEEFA. [Fast Erosion of Coal Plant Profits in the National Electricity Market](#). February 2021.

among the five coal power plants identified as vulnerable in our 2025 EBIT forecasts: Eraring, Mt Piper, Vales Point B, Gladstone and Yallourn.¹⁰

Of the five at-risk power plants, the most significant risk of insufficient notice of withdrawal probably lies with Vales Point B. Vales Point B is close to retirement (scheduled for 2029), so the owner has limited ability to recoup any investments aimed at maintaining its reliable operating life. This was evidenced in the decision of the owner to *not* go ahead with upgrades (in spite of these being granted government funding) stating ““Given that the ongoing operation of the Vales Point power station remains subject to market forces, and noting the current forecast closure date of 2029 may come forward or be deferred on the strength of these market forces, the benefits arising from the remaining life of Vales Point power station and the proposed project have been diminished by the passage of time.””¹¹

Also, the owner of Vales Point B is essentially a single asset corporate entity, so if the power station becomes financially unviable, financial penalties for insufficient notice of closure are impotent.

Lastly, the NSW Government capped the site remediation costs¹² faced by the owner at a relatively modest amount (just \$10m), with the remainder to be paid by NSW State (likely hundreds of millions), reducing the disincentive to exit.

In terms of the other power stations, the risk of insufficient notice is lower. This is more an issue of either:

- the ability to operate the plant safely, rather than one of pure financial viability; or
- one of simply tightening up obligations around notice obligations to remove potential loopholes that owners may be tempted to exploit (including sudden withdrawal defined as “mothballing”, which does not breach obligations).

The owner of Yallourn has already entered into an agreement with the Victorian Government to keep their plant operating until an agreed closure in 2028.

While the secrecy surrounding the terms of this Yallourn agreement is highly problematic and acts to deter competitors from investing in new replacement dispatchable capacity, it presumably provides some assurance that EnergyAustralia will not withdraw Yallourn's capacity without 42 months' notice.

The other three at-risk power stations are ultimately owned or operated by corporate entities (Origin Energy/Rio Tinto-CS Energy/EnergyAustralia) that have a range of other highly valuable assets and reputations to protect that will extend well beyond the life of the coal power plants at risk. If they were to operate these coal

¹⁰ IEEFA. [Fast Erosion of Coal Plant Profits in the National Electricity Market](#). February 2021.

¹¹ RenewEconomy. [Delta flagged early closure of Vales Point coal plant when it rejected federal grant](#). 19 April 2021.

¹² Renew Economy. [NSW Exposed to 'Unquantifiable Liabilities' for Vales Point Decommissioning, Documents Show](#). 12 July 2019.

generators in a capricious manner, there is scope for governments to penalise these companies either in a direct financial manner or indirectly, possibly through damage to their reputation or withholding of licences important to operating their other assets.

This does not mean the risk of abrupt withdrawal is completely solved for these entities, because poor profitability and limited future life create strong incentives to curtail maintenance expenditure. Over time, this will lead to greater difficulty operating the plant safely and reliably, and it can reach a point where continuing to operate the plant poses an unacceptable risk to human safety. At such a point, the owner can't be forced to keep the plant operating until repairs are made, which can involve long periods out of service. It can also lead to a greater probability of sudden mechanical failures or accidents.

Nevertheless, it is crucial to recognise that the risk of owners failing to give adequate notice of withdrawal, while real, is not a fatal flaw to our energy-only market.

The Likelihood of Abrupt Withdrawal Can Be Reduced With Better Regulation

In addition to the fact that the risk of abrupt withdrawal is constrained to a limited set of plants, greater efforts can be made to ensure that owners of large power plants adhere to their obligation to give adequate notice of withdrawal and to run plants reliably.

Applying penalties only after a breach occurs is highly problematic because the breach will tend to occur due to the generator falling into financial difficulty or physical failure. At this point, a financial penalty may be of little consequence because the entity is insolvent. Withdrawal of any operating licences may also be of no consequence because the business is unable to operate anyway.

Rather than applying penalties only after a breach occurs, 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 targeted only at plants that pose a significant risk of abrupt withdrawal.

Operators of these plants would be required to provide bonds calibrated to the amount of megawatts of each of their generating units which 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 level of reasonable 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, provided

that an assessment by the Australian Energy Market Operator (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 this penalty in place, at-risk generators can use mothballing as a loophole to avoid incurring the bond until the last minute. For this bond regime to work effectively in encouraging investors to build new plant to replace aging power plants they need to have confidence that once a power plant is announced as withdrawn, this doesn't suddenly change with little notice, reducing available demand and revenue for this new plant.

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 remove 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 someone else shuts down first, reviving its fortunes.

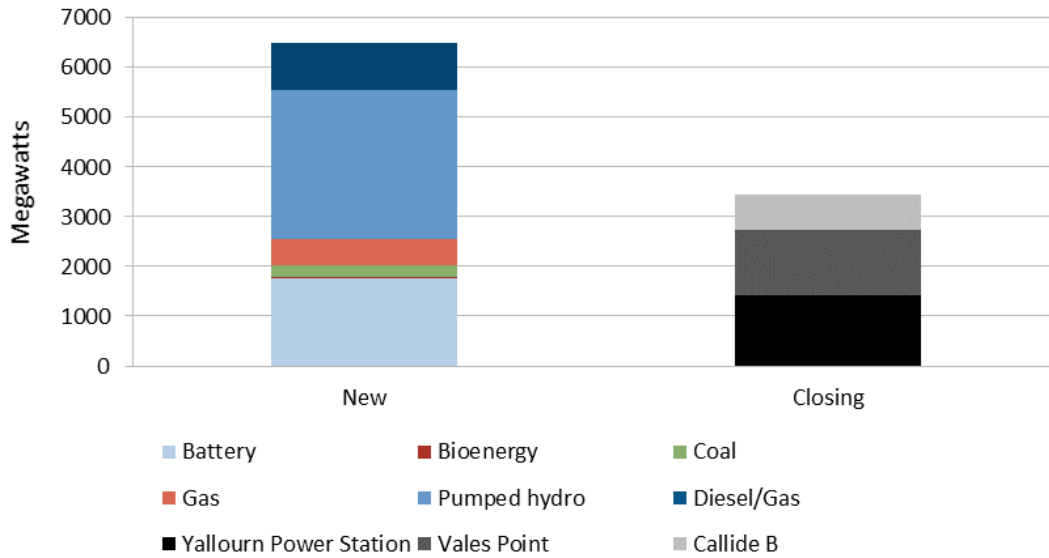
Other measures to manage the risk of abrupt withdrawal are also worth considering outside of a capacity market, which we will touch on in a subsequent report. This strengthening of the notice obligation is the first and most obvious step that avoids the far more costly and radical change of introducing a capacity market.

There Is an Influx of Dispatchable Capacity To Replace Coal

A reason we should be sceptical about claims that coal generators need to be rescued to keep the lights on is that there is a large influx of not just bulk energy from wind and solar, but also new dispatchable capacity entering the NEM since the Hazelwood Power Station closed.

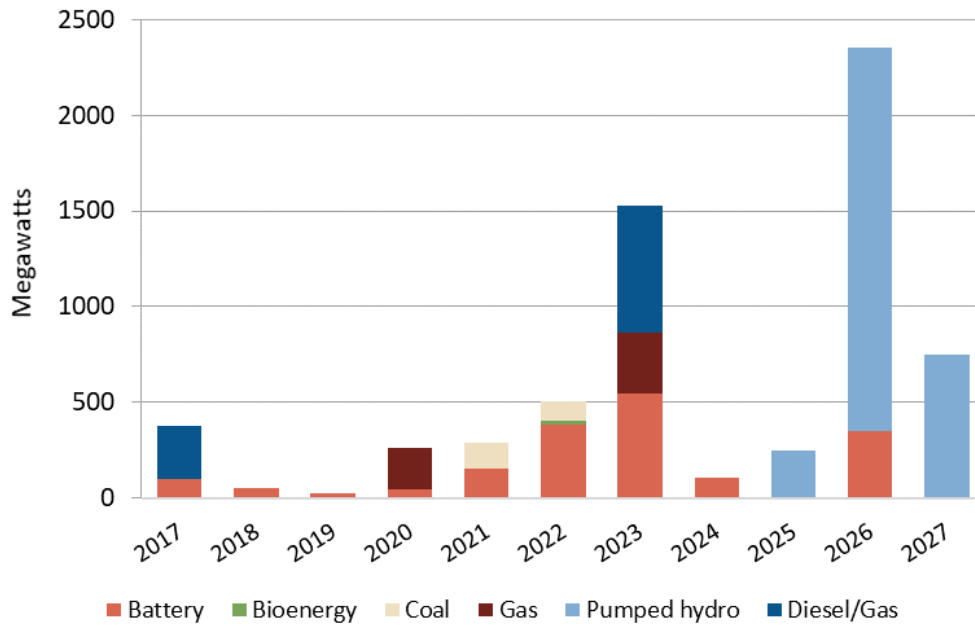
The chart below details the extra dispatchable capacity that will be added to the NEM in the decade since Hazelwood shut down in 2017 based on specific projects either committed, contracted, or underpinned by Federal Government commitment. All up, almost 6,500MW of new dispatchable capacity is due to be added to the NEM between 2017 and 2027. This is 1.9 times the capacity of the coal power stations – Yallourn, Vales Point and Callide B – scheduled to close soon after 2027.

Total Dispatchable Capacity Added to NEM Between 2017 and 2027 Compared to Capacity Lost from Closure of Yallourn, Vales Point B and Callide B



Source: Green Energy Markets Power Projects Database.

New Dispatchable Capacity Additions by Year Online



Source: Green Energy Markets Power Projects Database.

The previous chart illustrates the years that this capacity has or is expected to come online.

While a large amount is tied up in pumped hydro projects that involve long time frames, by 2023 there will still be more dispatchable capacity brought online (3040MW) than that due to be lost by the closure of Yallourn, Vales Point B and Callide B (3440MW).

It is also worth noting that the NSW Government is on the verge of implementing a policy initiative that will target a significant reduction in peak demand.

Also, there are several thousand megawatts of battery projects in development that could potentially proceed in the future and are not included in these figures because they are yet to proceed to being either contracted or under construction.

The Risk to Reliability Is Manageable

In addition, the AEMO 2020 assessment of power demand and supply, as well as their May 2021 update, envisaged levels of supply reliability would be maintained above the required standard (99.998% of all electricity demand met) across the entire outlook period for SA, Queensland (accounting for the closure of Callide B) and Tasmania. While for Victoria and NSW, the standard would be met all the way until FY2029.

After the closure of Yallourn coal power station in 2028, it was envisaged that supply would fall slightly short of the standard in Victoria (99.973% of demand satisfied). Although in reality, AEMO noted that provided EnergyAustralia built the 350MW battery they have publicly committed to building by 2026; then the reliability standard would be met. Therefore, Victoria's reliability standard is not at risk of being breached throughout the next decade.

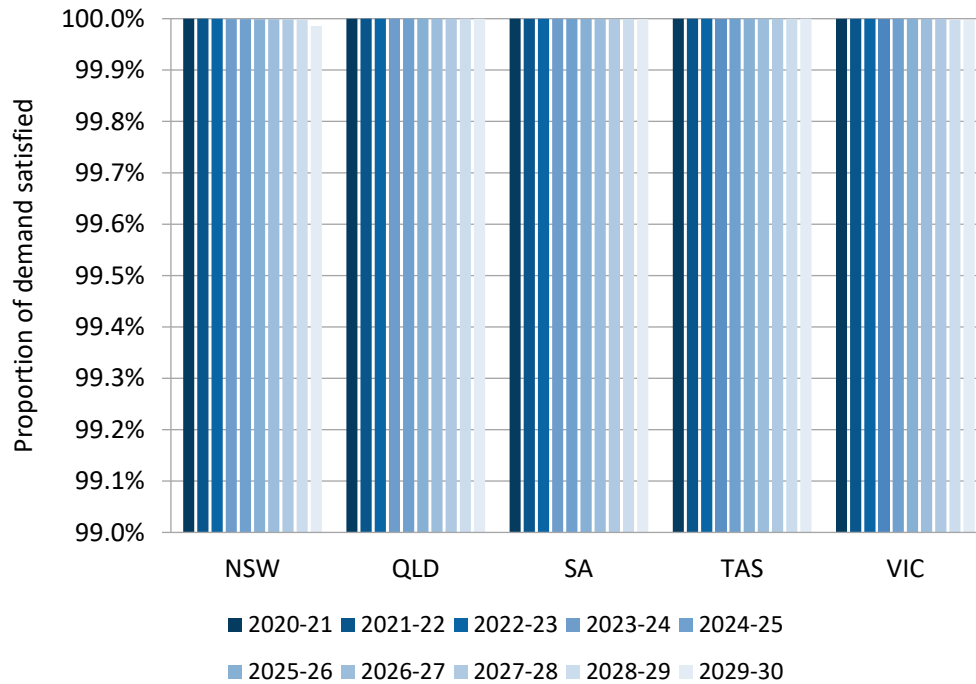
After the closure of Vales Point, it was envisaged that in 2029-30 NSW would also fall short of the standard, with 99.986% of demand satisfied (instead of the required standard of 99.998%).

However, this also fails to consider the range of additional dispatchable supply projects that are well advanced or which the Federal Government has committed to building and the NSW peak demand reduction scheme.

All up 3,200MW of the 6,500MW of dispatchable projects identified are not yet considered in AEMO's reliability assessment chart below.

This means that electricity supply is likely to be more than sufficient to meet the reliability standard across all states across the rest of the decade even after the closure of Yallourn and Vales Point.

Proportion of Electricity Demand Fully Satisfied From FY21 to FY30



Sources: AEMO 2020 Statement of Opportunities and AEMO Update to Statement of Opportunities – May 2021.

The Exit of Coal Is Unfolding Overseas Without Harming Reliability

Australia is not alone in facing a process where coal power plants exit the electricity market.

Many developed nations that Australia views as peers have maintained high levels of power system reliability, while coal generation has fallen dramatically over the past 15 years.

- In the United States, the amount of power generated from coal in 2020 was 62% lower than in 2005.
- In the United Kingdom, it was 96% lower than in 2005.
- Across the entire European Union, it had fallen by 55% relative to 2005 levels.

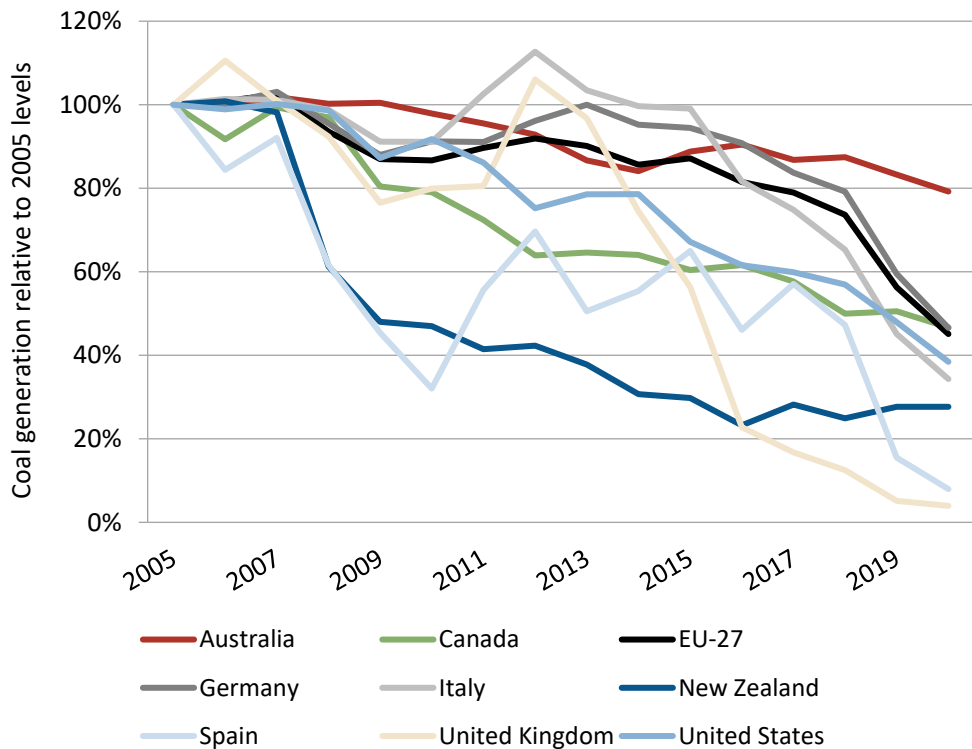
The proposal for consumers to pay generators for their latent capacity (while leaving the energy market price cap at an extremely high level) is clearly intended to help revive Australian coal generators' profits and delay their exit. Minister Taylor stated that the NEM "requires strong market signals that both encourage investment in new dispatchable generation to replace our aging thermal generator fleet, and

incentivise our existing thermal generators to remain in our market for as long as needed.”¹³

Yet this is contradictory to what is required for Australia to comply with international obligations to reduce emissions to net zero by no later than 2050 and contain global warming ideally to 1.5 degrees and well below 2 degrees, per the Paris Agreement.

Not only will this increase costs to electricity consumers, but it will also impose greater costs on taxpayers. This is because the Federal Government will need to make up for greater emissions from coal generators incurred by a capacity payment that keeps them online longer, by funding emissions abatement from other sectors of the economy via the taxpayer-funded Climate Solutions Fund (previously called the Emissions Reduction Fund).

Coal Power Generation Across Australia, Europe and North America – Generation Levels by Year as a Proportion of 2005 Levels



Source: Ember Global Electricity Review 2021 dataset.

¹³ The Hon Angus Taylor MP. Remarks at the 2021 Australian Energy Week Conference. 25 May 2021.

Consumer Groups and Most Other Stakeholders Do Not Support Introduction of a Capacity Payment

There is very little support for the proposal to make consumers pay generators for latent capacity, with support almost entirely isolated to owners of coal generators.

The ESB has publicly acknowledged this fact stating in their summary of stakeholder feedback:¹⁴

“Stakeholders were largely unsupportive of modifications to the RRO [to create a capacity payment] as either the case for change had not been made or the risk of imposing costs on consumers for little benefit was considered to be high.”

The ESB also recognised that groups representing electricity consumers and low-income households did not support it:

“Majority of large loads [i.e. consumers] did not see the case for change (Australian Aluminium Council) or think the RRO options [to establish a capacity payment] would deliver new investment or achieve the measures of success (Major Energy Users, EUAA and Bluescope). This was echoed by... other consumer groups including the Network of Illawarra Consumers of Energy and ACOSS.”

Nor did many non-integrated electricity retailers, according to the ESB:

“Majority of retailers including Flow Power, Shell Energy, Enova Energy were not supportive of modifications to the RRO, believing the case for change had not been made.”

And new technology energy businesses, including those providing “dispatchable” capacity did not support it either:

“Renewables/storage providers including CEC, Neoen, Enel GP, Enel X and Tesla did not support a physical RRO specifically as the case has not been made as to the benefits, retail competition is likely to be compromised and significant costs will be passed on to consumers.”

While no one likes to be hit with an extra charge, consumer groups are likely to be highly concerned about ensuring an adequate supply of electricity to avoid power blackouts and price spikes. You would expect they would be supportive of a capacity payment if they felt it was necessary to prevent these problems from occurring.

Electricity retailers are also likely to be concerned about inadequate generation supplies yet, the “majority of retailers” were not supportive of modifications to the

¹⁴ ESB summary of stakeholder feedback on the post 2025 options paper, which includes all the above quotes, is available [here](#). June 2021.

Retailer Reliability Obligation (RRO) to convert it to a type of capacity payment.

Lastly, you would expect providers of batteries like Tesla or demand response like Enel X (who would be recipients of capacity payments) to be open to the need for a capacity payment yet they too are opposed.

Where Is the Cost-Benefit Analysis to Justify this Major Change to Increased Centralised Control?

The National Electricity Market has delivered very high levels of reliability with an energy-only market design for over two decades. An energy-market only design was adopted and subsequently maintained not at a whim but after detailed consideration of its merits relative to one that also included a capacity payment. In the end, a capacity payment was rejected.

With increased levels of wind and solar in the mix and the falling cost of batteries, it is more important than ever that price signals faced by power generators are highly flexible to reflect changes in the supply-demand balance over short time periods. This is the very reason that regulatory authorities and Energy Ministers accepted the need to move to paying generators based on prices over five-minute intervals instead of 30 minutes.

A capacity payment reflects a move in the opposite direction towards a central planner attempting to guess at least a year in advance (and possibly greater) how much power supply we need, on what time periods and from what type of power plants. It could not only increase costs to consumers, but also potentially worsen reliability. This is because it could encourage the wrong types of power plants to remain operating while deterring the entry of newer, more reliable and more flexible power plants that are better suited to a grid with high levels of wind and solar.

The Australian Energy Council, the main representative group for electricity generators, including those that own coal generators, warned of this fact in its submission to the ESB¹⁵. It observed that the proposal for a capacity market requires a central planner to determine the power system's capacity requirements based on a highly simplified snapshot of the market's needs. The Council noted that this was, "no longer fit for purpose in many power systems and will soon become universally obsolete."

The Council added that it didn't believe it was clear that the ESB's proposals for ensuring adequate supply via a capacity payment were "capable of engaging with the future power system's true pinch points. Those being considered appear designed to reinforce the reliability of the old power system, rather than the new".

¹⁵ Australian Energy Council. [Australian Energy Council Response to Energy Security Board's Post 2025 Market Design Options Paper](#). 9 June 2021

It seems inconceivable that Energy Ministers could agree to such a major change in how the power market operates without a very thorough and detailed cost-benefit assessment given:

1. It is likely to impose significant new costs on consumers;
2. There is a lack of evidence to suggest a capacity payment is necessary to maintain reliability at its historically high standard;
3. It is contrary to the trend towards a greater diversity of power technologies where the speed of response is increasingly more important;
4. It is likely to increase the cost of emissions reductions, and slow the rate that Australia can reduce its carbon emissions; and
5. The lack of support for the change from consumers and most other electricity market stakeholders.

Appendix: Capacity Cost Calculation

The maximum capacity which needs to be procured through the capacity mechanism can be found using AEMO's forecast of peak demand. The ESB has suggested the PRRO would be based on the 1 in 2 year peak demand forecast (probability of exceedance 50% (POE50)).¹⁶ AEMO forecast a peak demand for operational generation in 2022/2023 combined across all the NEM regions of 37,161MW. (Table 1)¹⁷

Table 1: Annual Capacity Payments Power Bill Cost per Household Compared to Impact of Carbon Price by State

Year	Scenario	Category	Probability	Maximum Demand (MW)
2023	Central	OperationalGen	50	37161

Source: AEMO ESOO 2020.¹⁸

Western Australia (WA) provides a potential benchmark for the introduction of this capacity market. It is worth noting that WA only opted for this because they had inadequate competition. The level of the capacity payment is considerable, varying between a low of \$78,573/MW to a high of \$186,001/MW.¹⁹ Such a payment to cover the NEM's forecast peak in demand of 37,161MW would entail capacity payments of between \$2.9 billion and \$6.9 billion per year (Table 2). Using the most forward-looking capacity price forecast, 2022-23, would give a cost of \$3.2 billion per year.

¹⁶ Energy Security Board. [Post 2025 Market Design Options – A paper for consultation Part A](#). 30 April 2021. Energy Security Board. [Post 2025 Market Design Options – A paper for consultation Part B](#). 30 April 2021.

¹⁷ AEMO. [Electricity Statement of Opportunities 2020 Electricity Annual Consumption](#). 27 August 2020. (Based on 1 in 2 year (POE50) demand basis using the central scenario within their Electricity Statement of Opportunities 2020.)

¹⁸ Ibid.

¹⁹ AEMO. [WA Reserve Capacity Mechanism](#). 2021.

Table 2: NEM Capacity Market Cost Based on WA Capacity Price

Capacity Year	Reserve Capacity Price (\$ per MW per year) ²⁰	NEM Capacity Market Cost (\$ per year)
2022–23	\$85,294	\$3,169,632,458
2021–22	\$78,573	\$2,919,877,392
2020–21	\$114,134	\$4,241,359,305
2019–20	\$126,683	\$4,707,706,801
2018–19	\$138,760	\$5,156,499,358
2017–18	\$111,753	\$4,152,855,503
2016–17	\$121,889	\$4,529,536,425
2015–16	\$120,199	\$4,466,747,786
2014–15	\$122,428	\$4,549,563,698
2013–14	\$178,477	\$6,632,403,797
2012–13	\$186,001	\$6,912,017,496
2011–12	\$131,805	\$4,898,013,274
2010–11	\$144,235	\$5,359,956,429
2009–10	\$108,459	\$4,030,448,074
2008–09	\$97,835	\$3,635,659,625
2007–08	\$127,500	\$4,738,050,017
2006–07	\$127,500	\$4,738,050,017
2005–06	\$127,500	\$4,738,050,017

Source: Data from AEMO²¹ and IEEFA analysis.

Please note that the calculations of the cost are based on retailers in the NEM only paying for capacity up to the level of probability of exceedance of 50% (POE50) peak demand. In the WA market all capacity qualifying for capacity credits, even if it exceeds peak demand requirements, is paid the capacity price listed above (or even a higher price of no lower than \$114,000 if they are classified as a “transitional facility” which was a generator in place prior to 2018, which is in fact almost all of the generation capacity²²). If this design aspect from WA’s market were replicated in the NEM’s capacity payment scheme, then the cost would be noticeably greater than estimated in the table above. It is worth noting that due to a blow-out in capacity payment costs in the WA market, due in part to overestimates of required capacity²³, the WA Government had to introduce a series of changes to the capacity market which included measures that allowed the price for capacity to adjust downward for oversupply and slashing the price that demand reduction services were able to claim. However pre-existing generators argued that these changes represented an unfair change to the rules after investment had been committed and so they were provided with a more generous capacity payment as “transitional facilities”.

²⁰ AEMO. [WA Reserve Capacity Mechanism](#). 2021.

²¹ Ibid.

²² Ibid.

²³ Government of Western Australia - Department of Finance Public Utilities Office. [Electricity Market Review – Discussion Paper](#). July 2014.

The proportion of the \$2.9-\$6.9 billion capacity payment cost attributed to residential households is 40%, which is the mid-point of the estimated household contribution to peak demand according to the Australian Energy Market Commission 2012 Draft Report - Power of choice - giving consumers options in the way they use electricity, which stated, "various studies have shown that the residential contribution to peak demand can be as high as 35 per cent to 45 per cent on peak demand days".²⁴

The number of residential customers is sourced from the Australian Energy Regulator Annual Retail Markets Report 2019-20 at 6,423,649.²⁵

Dividing the total cost of the residential portion of the capacity market by the number of residential houses results in an annual average cost per household on their power bill in the realm of \$182 to \$430 (Table 3).

Table 3: Annual Capacity Payments Power Bill Cost per Household Compared to Impact of Carbon Price by State

	Reserve Capacity Price (\$ per MW per year)	NEM Capacity Market Cost (\$ per year)	Residential contribution to peak demand	Residential customers	Capacity market cost attributed to residential	Cost per residential customer
Minimum	\$78,573	\$2,919,877,392	40%	6,423,649	\$1,167,950,957	\$182
Maximum	\$186,001	\$6,912,017,496			\$2,764,806,998	\$430

Source: Data from AEMO, AEMC, AER and IEEFA analysis.

The carbon price impact on average household electricity bill was estimated by ACCC in the Australian Competition and Consumer Commission (2015) Information about the ACCC's operations during the June 2015 quarter relating to the carbon tax price reduction obligation.²⁶

In the case of NSW households, the capacity payment would exceed the impact of the carbon price by 41% to 234%. For Victoria it would be 62% to 284% greater, while for Queensland it would be 21% to 187% greater (Table 4). Note that unlike the carbon price where some of the revenue went to the government leading to substantial reductions in income tax (for example the threshold at which income tax became payable on income was lifted from \$6,000 to \$18,200²⁷), this capacity payment will go entirely from electricity consumers to the owners of generators without any compensating reductions in income tax.

²⁴ AEMC. Draft Report. Power of choice - giving consumers options in the way they use electricity

²⁵ AER. Annual Retail Markets Report 2019-20. November 2020.

²⁶ ACCC. Report to the Minister pursuant to s 60J of the Competition and Consumer Act 2010 Information about the ACCC's operations during the June 2015 quarter relating to the carbon tax price reduction obligation. July 2015.

²⁷ The Tax Institute. Government announces details of the proposed carbon tax. 11 July 2011.

Table 4: Comparison of Capacity Cost to Carbon Cost

State	ACCC estimate of Carbon cost ²⁸	Minimum capacity cost	Maximum capacity cost
		\$182	\$430
		Amount carbon cost exceeds min capacity cost	Amount carbon cost exceeds max capacity cost
NSW	\$129	41%	234%
VIC	\$112	62%	284%
SA	\$140	30%	207%
QLD	\$150	21%	187%
TAS	\$198	-8%	117%

Source: Data from ACCC²⁹ and IEEFA analysis.

²⁸ ACCC. Report to the Minister pursuant to s 60J of the Competition and Consumer Act 2010 Information about the ACCC's operations during the June 2015 quarter relating to the carbon tax price reduction obligation. July 2015.

²⁹ Ibid.

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