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Delaying coal power exits: A risk we can't afford

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Key Findings

Operational coal power stations in the National Electricity Market average 38 years old, close to the average historical retirement age of 42 years.

The reliability of coal power plants deteriorates as they near retirement – historical experience for plants that have closed indicates that leading into retirement 34% of their capacity is unavailable on average.

Proposals to extend the life of ageing power plants often fail to plan for poor coal reliability, which could lead to major electricity supply shortfalls. For example, analysis by Frontier Economics of a policy to delay coal closure assumed coal generation levels on average 9,300 gigawatt-hours per year (equivalent to the power consumption of 2 million households) higher than one would expect based on the historical availability of retiring plants.

To cover such a power supply shortfall using gas would strain the domestic supply of gas and lead to spikes in the price of electricity and gas.

Executive Summary

A large proportion of coal power stations in Australia are approaching an age when retirement becomes necessary. There are currently 15 operational coal-fired power stations across the National Electricity Market (NEM), with a total capacity of 21 gigawatts (GW) and an average unit age of 38 years. They are all scheduled to exit the system by 2051 per announced closure dates, or by 2040 per the Australian Energy Market Operator (AEMO)'s Step Change scenario.

In recent years several proposals or measures have been introduced to prop up the financial viability and technical feasibility of coal-fired power plants in the NEM in a bid to delay their closure. These are typically justified on the basis of ensuring power system reliability. Recently, Frontier Economics put forward modelling proposing delayed closure dates for a number of coal generators over the mid-2030s to mid-2040s, when they could be replaced by new nuclear reactors, justifying this pathway on the basis of lower cost. The Queensland government has also developed a new five-year plan with a focus on propping up coal plants, reportedly planning to extend the life of its Callide B plant beyond 2028, and potentially also extending the life of other state-owned plants in Queensland. However, these proposals and modelling exercises often don't adequately consider the risks and costs associated with heavy reliance on coal power stations at an age approaching or exceeding 40 years.

The existing coal fleet in the NEM is ageing, and nearing the age when Australian coal power plants have typically retired. Since 2000, 13 coal-fired power stations have closed in the NEM, totalling 8GW of capacity. Their average age on closure was 42 years. By 2030, almost two thirds of current operating NEM coal capacity will exceed this historical average retirement age.

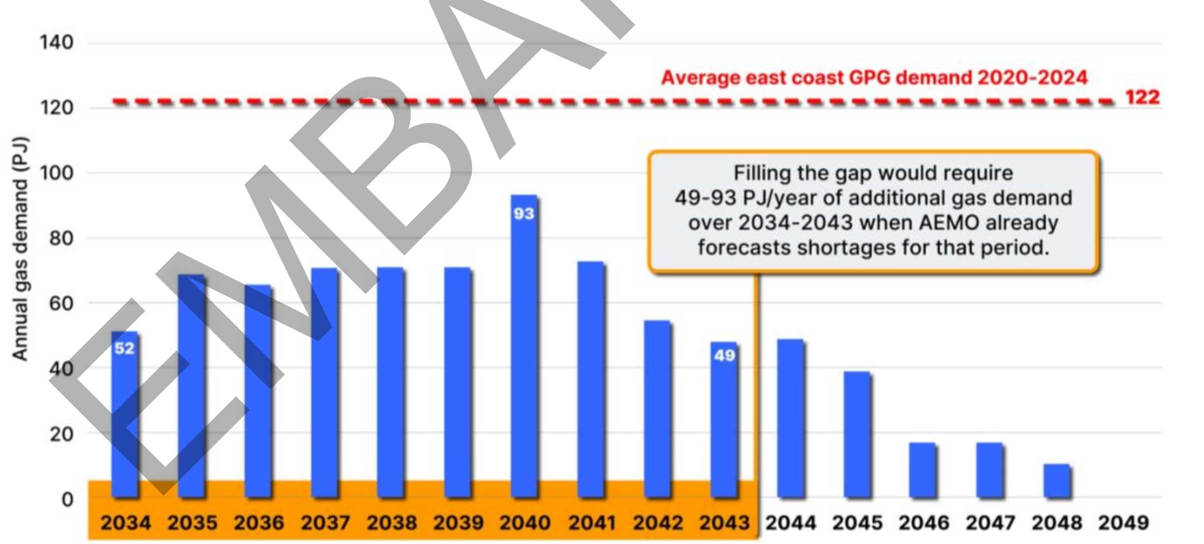
The reliability of coal-fired power stations typically declines as they age, due to the progressive degradation of critical plant components. Age-related wear and tear can increase the frequency of technical issues and outages as the plants need to reduce output or temporarily shut down units to undertake necessary repairs. Furthermore, operators often make strategic decisions to scale back asset management and capital investment in ageing coal plants, opting against major upgrades due to their limited remaining operational life and the shortened window to capture a payback on upgrade investments. Consequently, the overall reliability of coal-fired power plants – measured by their availability (the average proportion of a power plant's maximum generating capacity that is ready to inject power to the grid if requested) – diminishes as they approach retirement. Our analysis of the historical data for the closed power stations in the NEM found that the average availability of the closed coal power stations in the 10 years before they retired was just 66%.

Because of the deteriorating reliability of coal generators older than 40 years, a strategy to rely on coal power plant extension in the mid-2030s to mid-2040s poses a serious risk to electricity reliability. The modelling by Frontier Economics features assumptions about coal plant availability that are inconsistent with the historical experience of Australian coal plant near to or exceeding the typical retirement age. Once we correct for the likely poorer availability of coal power plants in the 2030s and 2040s (by adjusting the utilisation or capacity factor down to 66% instead of the modelled range of 72% to 81%), a substantial electricity supply shortfall is evident. This ranges between 6,800 and 13,000 gigawatt-hours (GWh) per year over the first 10 years of the shortfall (2034-43 inclusive) – or 9,300GWh per year on average over the period. To put this in perspective, that is equivalent to the annual electricity consumption of 1.4 million to 2.8 million typical homes over 2034-2043 – or 2 million homes on average across the period.

To bridge such gaps with additional renewable energy and battery storage would require several years lead time in advance of the expected shortfalls in 2034 due to the time involved in constructing such new plants. In addition, for such investments in new plant to be commercially attractive, there would need to be a consequent scale-back in any proposed government-subsidised nuclear build.

The alternative option of ramping up output from gas-fired power plants would face considerable practical constraints. Existing and new gas plants would need to significantly increase their generation, but there are questions over the source of this additional gas. Filling the gap with gas-powered generation would require between 49 and 93 petajoules (PJ) per year of additional gas over 2034-43 (67PJ per year on average). This represents a substantial increase in east coast gas demand for power generation, equal to between 40% to 76% of the average past five-year annual gas use for electricity generation of 122PJ per year. Such a surge in gas demand would be highly inflationary and challenging for energy security, given that AEMO forecasts significant shortages of gas supply for that period.

Additional unplanned gas demand required to make up for lower coal availability



Source: IEEFA analysis, AEMO data on historical gas demand from GSOO 2025. Note: GPG = gas-powered generation.

Low coal availability also increases the risk of power price rises. Low coal availability levels can drive wholesale prices upwards during outage periods, because other more expensive forms of generation often will step in when coal outages occur. This has been observed recently by the Australian Energy Regulator (AER) and AEMO. A study by Jacobs for the Clean Energy Council found that household power bills in the NEM could rise by $449 per year by 2030 if we had greater reliance on gas and coal and if renewables were built more slowly. Household bills could rise by $606 per year by 2030 if this occurred *and* a major coal-fired power plant failed unexpectedly.

An extended reliance on old power plants and their associated mine sites also poses risks to worker and community safety. As power plant equipment ages it becomes more prone to catastrophic failures that can lead to dangerous accidents. This has been seen in historical fires at Hazelwood, Yallourn, Morwell and Northern, and in technical issues leading to dangerous explosions seen at Muja AB, Yallourn, Hazelwood and most recently Callide C.

A strategy of extending the life of coal power plants depends on owners making substantial investments in refurbishment. Historically some owners have rejected refurbishment projects as not cost-effective; others have undertaken refurbishment projects that ended disastrously. High costs were seen with proposed or finished refurbishments at Muja AB, Hazelwood and Liddell, with project costs ranging from $400 million to $1.3 billion (in 2025 dollars). For both Hazelwood and Liddell the refurbishment cost was deemed too expensive and problematic to be worth pursuing. For Muja AB, refurbishment did go ahead, but the project had many technical issues and cost overruns, and the plant only operated for a short time at an extremely low utilisation rate – reportedly 20% – before closing.

Banks are reluctant to finance coal power plant projects, meaning refurbishment projects may struggle to access financing from the private sector. In a recent refinancing round, Delta Electricity, the owner and operator of Vales Point power station, found that all 15 banks approached were unwilling to provide finance to support the ongoing operation of the coal power station due to policies relating to management of environment, social and governance issues.

The risks associated with coal extension could be exacerbated if the generation technology chosen to replace coal cannot be installed in the required timeline. This is of greater concern if the generation technology chosen to replace coal has long and uncertain lead times – as is the case with nuclear power. Nuclear timelines often blow out significantly. The average historical time overrun across four recent nuclear projects in Europe and the US was 11 years. If the ramp up of nuclear power generation occurred 11 years later than expected in the Frontier Economics modelling, there would be a significant potential energy supply gap, ranging from 9,600GWh to 94,500GWh per year between 2036 and 2051. To fill this potential gap would require either *further* life extensions to coal, compounding the aforementioned risks, or it would require an increase in other electricity generation sources. As new operators of electricity generators would not have a strong incentive to invest for the long term given the planned introduction of nuclear power, it could create a "dead zone" for investment, making it challenging to secure energy supply in this period.

Relying more heavily on coal power for longer carries a range of associated risks and costs, including risks to reliability, power prices, safety, extension costs and financing risk, as well as major implications for emissions. Delaying coal exits is a risk we can't afford.

Introduction

This report uses historical information on the operation of past retired coal power stations as well as still operating coal plants in Australia's east coast National Electricity Market (NEM) to illustrate the serious risks associated with a strategy of extending the life of Australia's existing coal power stations. This report builds on prior research IEEFA has published examining coal power plant financial viability and regulatory measures seeking to ensure power system adequacy/reliability.

In a February 2021 report, *Fast Erosion of Coal Plant Profits in the National Electricity Market*, IEEFA highlighted that several coal generators in the NEM were likely to suffer serious challenges to their financial viability and were at high risk of closing early.[1] Within months of that report being issued, the analysis was proven correct, with two of the generators identified as at risk of closure – Eraring and Yallourn – announcing their intention to close many years earlier than originally planned.

When issuing the warning of likely early closure, we also recommended that state and federal governments put in place a policy framework that would support investment in new generating capacity and demand management. This would ensure coal plants could exit the market in a timely manner that would minimise risks to reliability and price increases. Each individual coal power plant can represent a large portion of their state's power supply and peak demand capacity. If it exits without sufficient new plant being built in advance to cover the gap, this can have serious impacts in terms of price and reliability. In addition, because these plants tend to be a large source of supply, replacing them with new plant and equipment takes time; it can't be done overnight. So it is important to plan and prepare for coal power plant closures several years in advance.

In our February 2021 report, we emphasised that seeking to prop up the financial viability of coal generators to prevent or delay closures could be highly counter-productive to ensuring reliable and affordable supply. That was because such coal power plants were quite old and likely to be unreliable, and subsidies to these plants would likely not alter that physical reality. At the same time such interventions would also deter the very investment in new, low-emissions plant that would provide the fundamental long-term solution. Interventions to extend the life of coal generators should essentially be last-resort measures with clear quantitative metrics around why the plant is needed, which once addressed through investment in new capacity would lead to the closure of the plant.

Since that report was issued there have been positive developments in addressing some of the issues we highlighted. In particular the Federal Government's Capacity Investment Scheme will help accelerate investment in new energy supply to replace exiting coal generators. However, it remains apparent that governments do not always appear to be heeding warnings about the problems and risks associated with intervening to delay the exit of coal generators outlined in our February 2021

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

report, and a follow-up report we issued in September 2021, *There's a Better Way To Manage Coal Closures Than Paying To Delay Them*.[2]

For example, there are opaque arrangements between the Victorian government and Energy Australia to keep Yallourn open until 2028; and the New South Wales (NSW) government has a contract to shield Origin Energy from losses from the continued operation of Eraring, as well as an Orderly Exit Management Framework in play.

More recently, it has been reported that the Queensland government has developed a new five-year plan that includes a focus on propping up coal plants, reportedly planning to extend the life of Callide B beyond 2028. Other state-owned plants in Queensland could also see life extensions by the end of 2025. Reportedly the strategy could include refurbishments of Callide B and Tarong.[3,4] Detailed information around this proposal is not currently available at the time of writing this report.

There remains a risk that measures to prop up the financial viability and technical feasibility of coal generators to delay their closure could become an embedded, widespread, structural feature of our electricity market. This would act like a brake on efforts to decarbonise the Australian economy, increasing the cost and difficulty of achieving our emission reduction targets. The Energy Security Board's proposed Capacity Mechanism (colloquially labelled as "Coal-Keeper") had a number of flaws that meant it could have become such a brake.[5] More recently, modelling prepared by the consultancy Frontier Economics – envisioning a scenario where a number of coal power plants' operations are extended beyond their current owners' nominated retirement dates until they can be replaced by nuclear – appears to embody and tacitly recommend such a policy outcome.

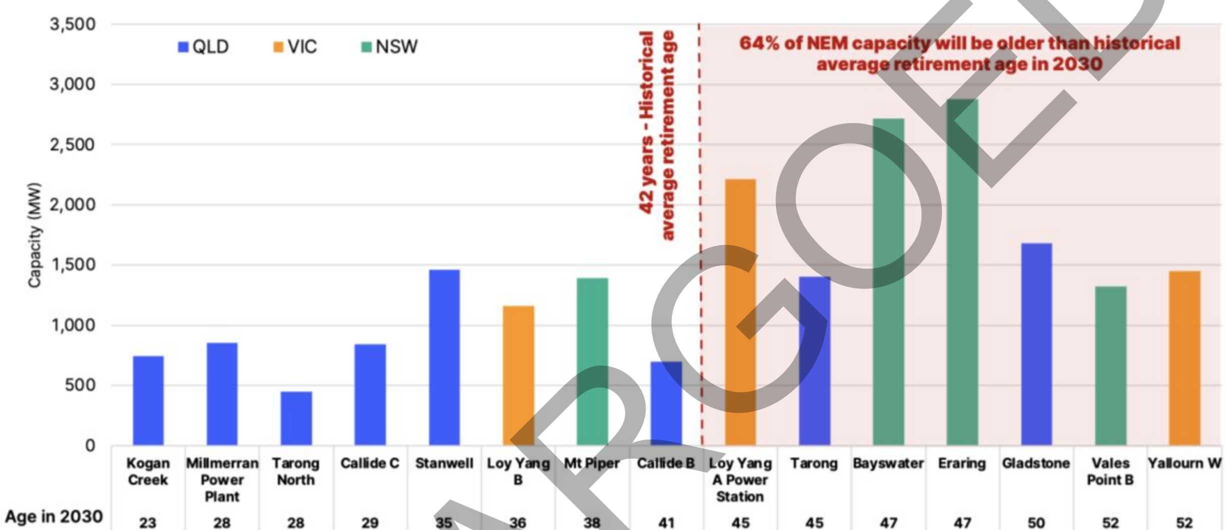
This modelling, a range of other commentary in the media calling for further extensions in the operation of Yallourn and Eraring, and the recently reported Queensland government strategy do not adequately recognise that coal power plants typically suffer serious reliability and safety problems as they approach and exceed 40 years of age. In this report IEEFA seeks to correct for this inadequate consideration of the costs and risks associated with relying on old coal power plants. It does this by analysing the historical experience from past Australian coal power plants that have closed, as well as some of the issues being experienced by operating power plants.

[2] IEEFA. There's a Better Way To Manage Coal Closures Than Paying To Delay Them. September 2021.
[3] Australian Financial Review (AFR). Queensland tears up transition targets and will keep coal for longer. 8 April 2025.
[4] RenewEconomy. "Fiscal vandalism:" Queensland doubles down on coal and gas after transmission, hydro cost blowouts. 8 April 2025.
[5] IEEFA. There's a Better Way To Manage Coal Closures Than Paying To Delay Them. September 2021.

Australia's coal-fired generation fleet is ageing

Since 2000, 13 coal-fired power stations have closed in the NEM, totalling 8GW of capacity. The average age of these power stations when they closed was 42 years.[6] Many of the remaining 15 coal power stations are already past this age or not far from it. By 2030, 64% of the remaining coal fleet capacity will be older than typical age at which NEM's coal power plants have retired in the past.

Figure 1: Age and capacity of the existing coal-fired power plants in the NEM



Source: AEMO Generation Information January 2025;[7] AEMO generating unit expected closure years January 2025;[8] Commissioning dates are from: company websites; Global Energy Monitor (GEM);[9] University of Melbourne;[10] Leading Edge Energy.[11] See Appendix for further detail.

Reliability drops as power plants approach retirement

In its 2023 State of the Energy Market report, the AER observed, "Coal generators break down more frequently as they age – the NEM's aging fleet of coal generators is particularly prone to outage as stations near the end of their lives."[12]

> **The NEM's aging fleet of coal generators is particularly prone to outage as stations near the end of their lives.**

[6] See Appendix for full list of closed generators and ages, including references.
[7] AEMO. NEM Generation Information. January 2025.
[8] AEMO. Generating Unit Expected Closure Year. January 2025.
[9] GEM. Global Coal Plant Tracker. Accessed February and March 2025.
[10] Climate Energy College, University of Melbourne. Retirement of coal fired power stations. 10 November 2016. *Dylan McConnell*.
[11] Leading Edge Energy. The timeline for coal exit in Australia's power generation fleet. Accessed February 2025.
[12] AER. State of the Energy Market 2023. October 2023. Page 59.

Meanwhile, AEMO noted in its 2024 Integrated System Plan that, "Unplanned coal generator outages are becoming more common as the fleet ages."[13]

Much like a motor car, coal power plants are subject to considerable thermal and mechanical stress, which leads to components wearing out over time. With appropriate maintenance they usually maintain reliable performance for several decades, but as they approach and exceed 40 years of age this becomes increasingly difficult and costly. Further, ageing plants become prone to increased risk of accidents; components can catastrophically fail leading to dangerous explosions and fires that threaten the safety of workers and potentially even the surrounding community.

This deteriorating reliability can be measured by their availability. Availability is a measure of the proportion of capacity that a power plant is capable of supplying to the system over time. So a power plant with 1,000MW of capacity and average availability of 60% would be capable of providing 600MW of power on average across the year rather than its total rated 1,000MW of capacity. Availability can decline due to:

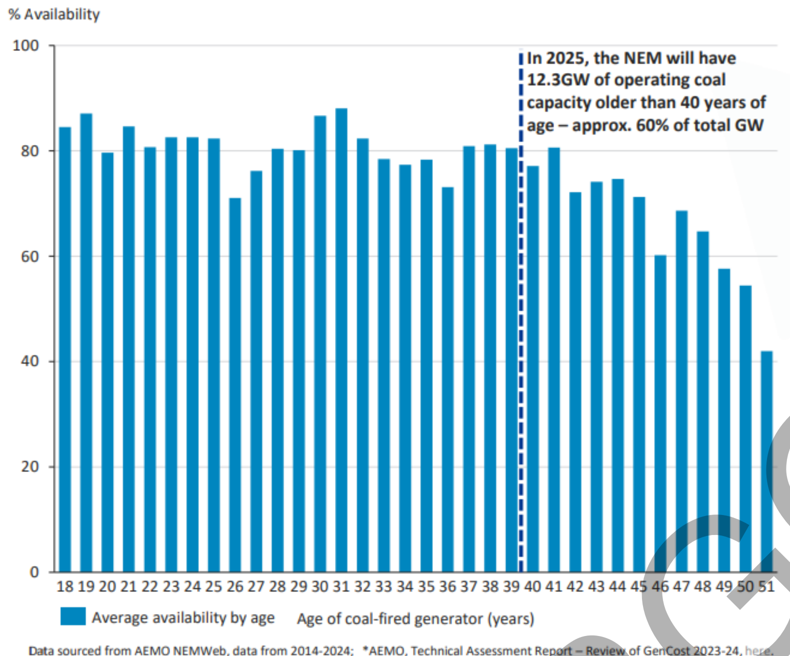
- More unplanned outages:
  - Increased incidence of breakdowns, known as a forced or unplanned outages, (represented by the Forced Outage Rate, FOR).
  - Increased incidence of operating at an unplanned reduced level due to technical reasons such as trying to reduce stress on equipment (represented by the Effective Partial Outage Rate, EPOR).
- More planned outages:
  - The plant needs an increased amount of time out of service for scheduled maintenance to inspect and pre-emptively repair fatigued equipment.

Unavailability is the total of unplanned outages and planned outages. Unplanned outages tend to be the most disruptive to the power system because they unfold suddenly without advance warning, leaving little time for other power stations to step into the breach. Planned outages for scheduled maintenance are usually undertaken outside peak demand periods, when there is lower risk to the system if a generator is offline.

Availability has been found to decline as coal generators age. According to Baringa, coal generators younger than 40 years had an average availability of 81%, and generators over 40 years old exhibited average availability of 65% over 2014-2024, with availability trending downward as the generator aged.[14]

[13] AEMO. 2024 Integrated System Plan for the National Electricity Market. 26 June 2024. Page 16.
[14] Baringa. The challenge of ageing coal generators and the growing role of storage in grid reliability. 2025. Page 4.

Figure 2: Average availability of generating capacity by age



Source: Baringa[15]

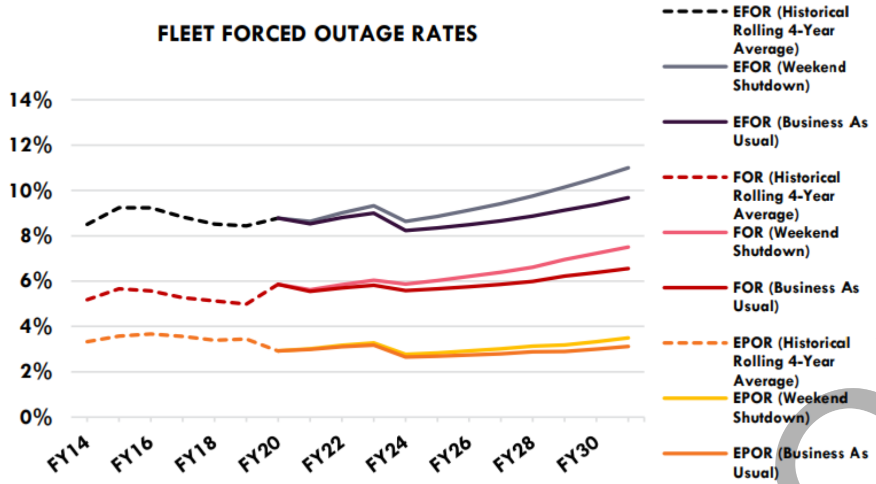
Our own analysis of the operational performance of the 13 coal power plants that have retired since 2000 indicates that the average level of availability in the 10 years prior to closure was 66%.[16]

A study by engineering firm AEP Elical, prepared for AEMO, provides insights into the key reasons generators experience outages, and how they can change with age.[17] AEP Elical found that the main causes of unplanned "forced" coal unit outages (i.e. a unit being offline, represented by the FOR) were issues with boilers, flue gas and ash systems and steam turbines. The main causes of unplanned partial outages (i.e. a unit operating at an unplanned reduced level, represented by the EPOR) were issues with flue gas and ash systems, condenser and feed heating systems, fuel supply and fuel systems.

Moreover, AEP Elical found that these issues and other issues with coal units occur more frequently with age, leading to more unplanned outages, as shown in the chart below. The Effective Forced Outage Rate (EFOR – which combines FOR and EPOR) increases to about 10% in FY2030, meaning the coal fleet is expected to be offline for unplanned outages about 10% of the time.

[15] Baringa. The challenge of ageing coal generators and the growing role of storage in grid reliability. 2025. Page 4.
[16] Based on AEMO data. See the Appendix for detailed data and information.
[17] AEP Elical. Assessment of Ageing Coal-Fired Generation Reliability. 30 June 2020.

Figure 3: NEM coal fleet outage rates



Source: AEP Elical[18]

Planned outages, on the other hand, were considered by AEP Elical to generally continue as normal as plants near retirement. However in the last four years or so of operation, AEP Elical expected that maintenance expenditure would be reduced to meet statutory obligations only, which would result in likely increases in unplanned outages.

The fact that coal power plants' reliability deteriorates as they become old is partly an inevitable physical aspect of subjecting equipment to thermal and mechanical stress over time. However, it is also a function of financial considerations, as owners trade off increased costs of maintenance and repairs against the expected revenue that they might be able to capture from that expenditure.

Coal power plants plan their investments based on how long they expect to stay open. In the final years before closing, it becomes harder for the coal plant to justify spending on upgrades given there's little time left to recover those costs.

According to AEP Elical, as plants reach end of life, investments on the power stations reduce, and the focus is on extending the life of critical items rather than replacement. This leads to higher forced outage rates. AEP Elical states: "As stations draw towards their end of life, i.e. 6 to 7 years prior to scheduled closure, the asset management plans generally consider reduced investment in plant maintenance. Station owners will provide sufficient investment in order to meet plant certification requirements and to meet any performance obligations under Power Purchase Agreements or other contractual arrangements. Investment in capital plant and equipment is unlikely and focus is on extending the life of critical items, rather than replacement. This inevitably results in a managed reduction to overall plant availability, with increases to both forced and partial outages."

[18] AEP Elical. Assessment of Ageing Coal-Fired Generation Reliability. 30 June 2020. Page 27.

The table below shows AEP Elical's "opinion on the impact that aging plant and equipment, coupled with the aforementioned reduction in CAPEX and OPEX has on FORs in the final years of Station operation. The increases are cumulative and show an increasing rate of change as end of life is approached." [19]

Table 1: AEP Elical – End of life growth in Forced Outage Rates (FOR)

End of life growth per annum				
Scenario	Three years in	Two years in	One year in	End of Life
Business as Usual	0.25%	0.30%	0.40%	0.50%
Weekend Shutdowns	0.25%	0.30%	0.40%	0.50%

Source: AEP Elical[20]

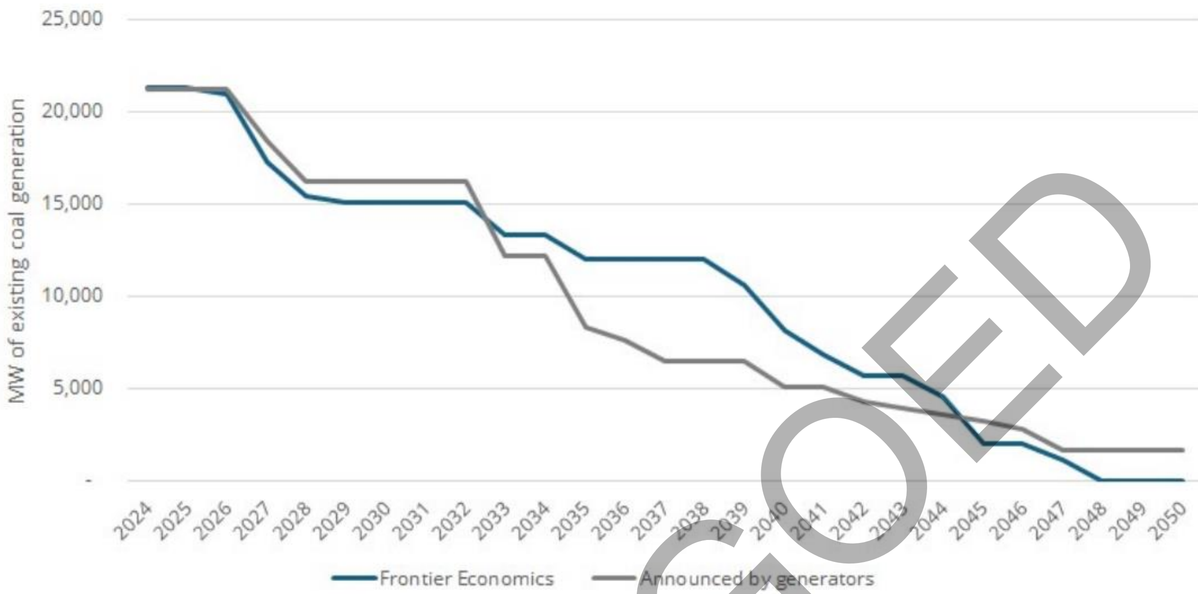
Proposals for governments to extend the life of the NEM's existing coal power stations are likely to encounter reliability problems given that the owners of a large proportion of coal plant capacity are currently planning on shutting their power stations over the 2020s to mid-2030s. Therefore, these owners are likely to currently be aiming to phase down their maintenance expenditure.

Relying on coal power plant extensions could lead to energy supply shortfalls

Modelling prepared by Frontier Economics proposes that substantial economic savings could be achieved by slowing growth in renewable energy (relative to AEMO's Step Change scenario) and instead placing far greater reliance on the existing coal-fired generators over the mid-2030s to the mid-2040s, until nuclear power plants could be built over the late 2030s and 2040s. This modelling includes an explicit extension in the operation of several coal generators beyond the closure dates the owners have announced, as shown in Figure 4.[21]

[19] AEP Elical. Assessment of Ageing Coal-Fired Generation Reliability. 30 June 2020. Page 23.
[20] Ibid.
[21] Frontier Economics. Report 2 - Economic analysis of including nuclear power in the NEM. December 2024.

Figure 4: Generator closures assumed in Frontier modelling vs announced closures



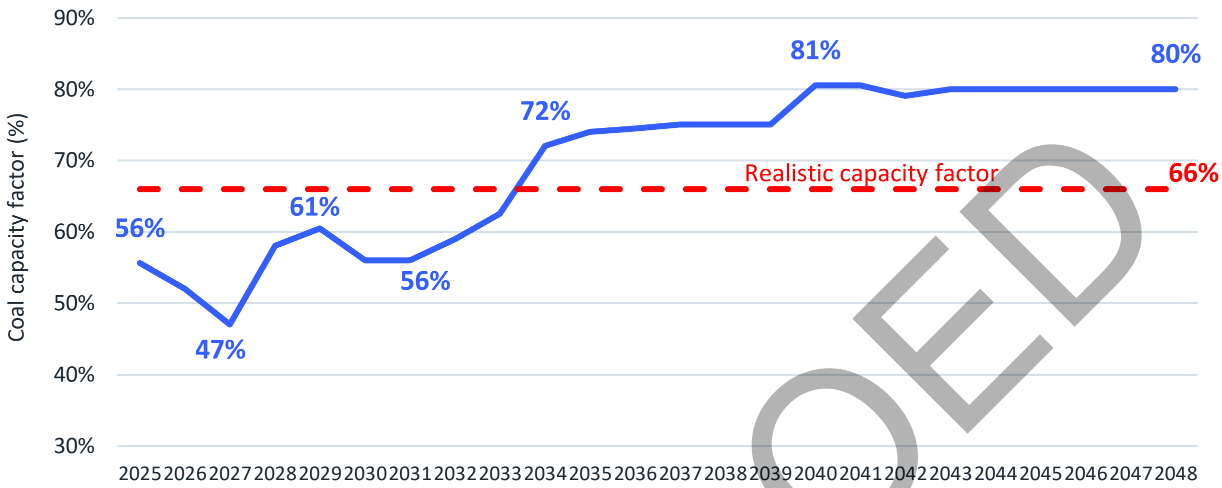
Source: Frontier Economics Report 2[22]

The issue with the Frontier Economics coal extension strategy is that it assumes a level of availability that historical evidence suggests is far greater than the average coal plant tends to achieve when it is close to or exceeding typical retirement age.

The chart below illustrates the implied utilisation or capacity factor of coal power plant capacity each year, which we've derived from the charts within the Frontier Economics report. This is the proportion of coal capacity actually used to generate power – which is not the same as availability. Availability is a measure of what coal power plants would be technically able to generate if they were needed by AEMO. What they actually generate (their capacity factor) is always less than availability because often they are outcompeted in the electricity market by cheaper plants. Even the very low-cost coal generators of Loy Yang A and B have capacity factors around 5% below their availability.

[22] Frontier Economics. Report 2 - Economic analysis of including nuclear power in the NEM. December 2024.

Figure 5: Frontier Economics capacity factor of coal vs realistic capacity factor



Source: IEEFA representation of Frontier Economics modelling. Note: A chart scraping tool has been used to obtain the data from Frontier Economics Report 2 so the Frontier figures are approximate. The realistic capacity factor has been drawn from historical experience of coal power plant availability in the years leading up to retirement. See Appendix for further information.

Initially in the Frontier Economics forecast period, the capacity factor of coal is at levels similar to historical experience and below the availability levels of past retired coal plants in the lead-up to retirement. However, from 2034 onwards, the assumptions around coal power plant capacity factor look increasingly unrealistic, given the age of the power plants involved. Over 2034-48 the fleet-wide capacity factor is between 72% and 81%. This would imply fleet-wide availability levels around 77% to 86% based on the difference between availability and capacity factor experienced at the low-cost Loy Yang A and B generators since 2016. While such levels of availability are not out of the ordinary for high-performing coal power plants in their middle age, they are well above the average levels we've seen in the closed power plants as they approached retirement – which was 66% on average in the 10 years before exit.

Now it might be argued that, under this alternative scenario modelled by Frontier Economics, coal power plants will be subsidised to maintain better availability than what we've seen historically from plants nearing retirement. Yallourn Power Station might therefore be a better proxy, as it has enjoyed a support agreement with the Victorian government. Even in this case its availability over the past three years (2021 to 2024) has been around 70% and its capacity factor around 65%.

The table below details Frontier Economics' modelled levels of coal generation and capacity factor from 2034 to 2048 in gigawatt-hours. It then outlines coal generation levels using a more realistic 66% capacity factor. It then details the resulting shortfall in annual generation in gigawatt-hours. To put that in terms that people can relate to, we've translated the shortfall into an equivalent number of households' power consumption that would be unserved in the year if coal performance was more aligned with the historical experience.

Table 2: Generation shortfall relative to Frontier Economics model using realistic capacity factor for coal plant nearing retirement

Year	Frontier Coal Generation (GWh)	Frontier Coal Capacity Factor	Realistic Coal Generation (66% capacity factor)	Annual shortfall (GWh)	Equivalent number households without power
2034	85,702	72%	78,506	7,196	1,530,975
2035	88,082	74%	78,506	9,576	2,037,487
2036	81,077	75%	71,777	9,300	1,978,619
2037	81,621	75%	71,777	9,844	2,094,393
2038	81,621	75%	71,777	9,844	2,094,393
2039	81,621	75%	71,777	9,844	2,094,393
2040	71,756	81%	58,791	12,965	2,758,583
2041	56,195	81%	46,041	10,154	2,160,336
2042	45,857	79%	38,285	7,572	1,611,145
2043	38,705	80%	31,910	6,795	1,445,809
2044	38,705	80%	31,910	6,795	1,445,809
2045	30,973	80%	25,535	5,438	1,156,968
2046	13,790	80%	11,369	2,421	515,116
2047	13,790	80%	11,369	2,421	515,116
2048	8,120	80%	6,694	1,426	303,299

Source: IEEFA analysis, based on information from Frontier Economics Report 2. Note: A chart scraping tool has been used to obtain the data from Frontier Economics Report 2 so the Frontier figures are approximate. The consumption of a median household averaged across NSW, South-East Queensland, Victoria and South Australia was found to be 4.7 megawatt-hours (MWh) per year, based on data from the Australian Competition and Consumer Commission (ACCC).[23] This was used to determine the equivalent number of households without power.

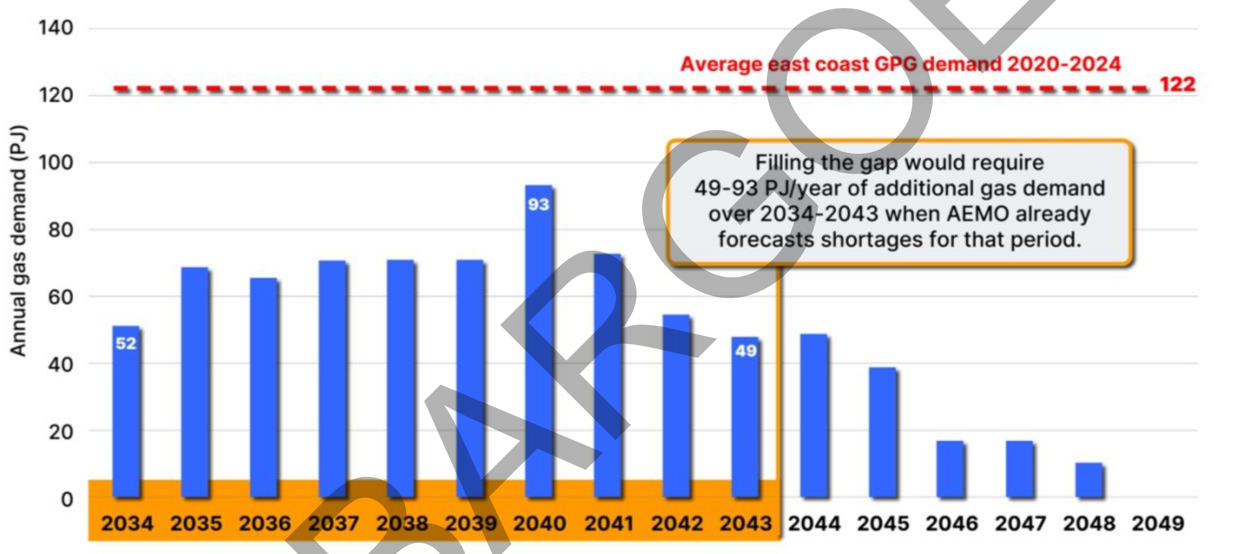
The scale of annual coal generation shortfalls is quite significant, ranging from 6,800 to 13,000 GWh/year over the first decade of the period (2034-43 inclusive). On average this equals 9,300GWh over the period 2034-43. This is equivalent to the annual energy supply of 1.4-2.8 million homes over 2034-43 – or 2 million homes on average over the decade.

To bridge such gaps with additional renewable energy and battery storage would require several years lead time in advance of the expected shortfalls in 2034 due to the time involved in constructing such new plants. In addition, for such investments in new plant to be commercially attractive there would need to be a consequent scale-back in any proposed government-subsidised nuclear build, which would effectively act as a competitor to these renewable energy and battery investments.

[23] ACCC. Inquiry into the National Electricity Market report - June 2024. Appendix E - Supplementary spreadsheet with billing data and figures - Inquiry into the National Electricity Market report - June 2024. 28 June 2024.

The alternative option of ramping up output from gas-fired power plants would face considerable practical constraints. The chart below illustrates the extra petajoules of gas that would be needed to fuel combined-cycle gas turbines to generate an amount of electricity equal to the coal generation shortfall detailed in the table above. The extra gas required would be considerable, at 49-93GJ per year over the first 10 years (2034-43), or 67PJ per year on average over the period.[24] In the below chart we also include the historical east coast gas-powered generation (GPG) demand over 2020-2024, which is 122GJ. It is clear that the additional potential gas demand required is very significant, ranging from 40%-76% annual increase in GPG demand over 2034-2043.

Figure 6: Additional unplanned gas demand required to fill gap from coal underperforming relative to Frontier Economics modelling



Source: IEEFA analysis, AEMO data on historical gas demand from Gas Statement of Opportunities (GSOO) 2025.

AEMO is projecting inadequate supplies of gas across NSW, Victoria and South Australia over 2029 onwards.[25] Therefore, such a large increase in the demand for gas, potentially driven by sudden surges in demand as a result of unplanned coal plant outages, would be highly problematic. It would also mean gas prices would likely remain elevated and tied closely to international prices for liquefied natural gas (LNG).

[24] IEEFA calculation using Gas Demand (PJ) = Electricity Generation (TWh) × 3.6/Efficiency (%), where Efficiency = 50%, typical of a combined cycle gas turbine.
[25] Australian Energy Market Operator. Gas Statement of Opportunities. March 2025.

Electricity price impacts

Relying on coal for longer while it is ageing and has reducing reliability would also have significant flow-on impacts on electricity prices given the high cost of generating power from gas. The AER in its 2023 State of the Energy Market Report observed:

> *"Coal generators break down more frequently as they age – the NEM's aging fleet of coal generators is particularly prone to outage as stations near the end of their lives. … Outages of coal plant, particularly unplanned outages, were a significant contributing factor to the record high prices of the April to June quarter 2022, which saw the spot market suspended for the first time in the NEM's history. In the April to June quarter 2022, coal outages in the NEM reached nearly 8 GW compared with historical averages of 3 to 4 GW. This saw a large portion of electricity demand shifted to more expensive gas generators, which were not prepared or appropriately contracted for the additional workload."* [26]

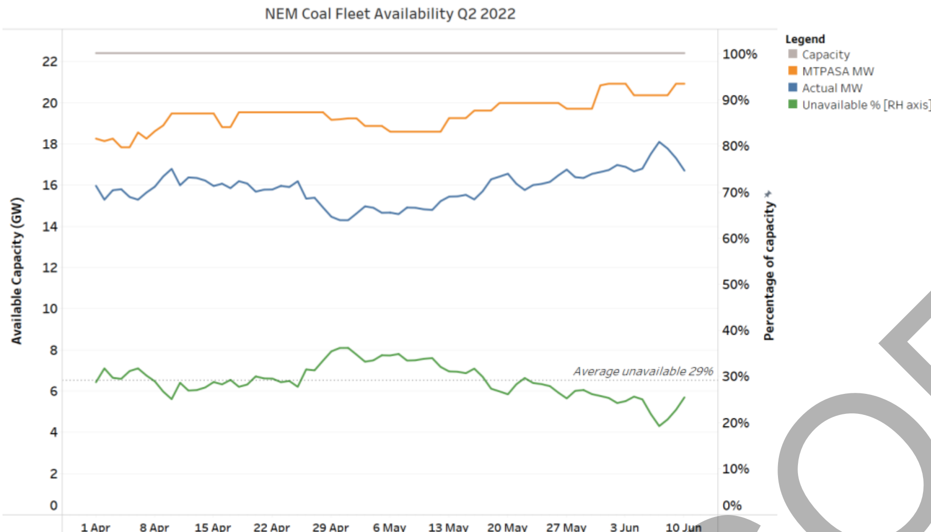
More recently, in quarter four of 2024, AEMO found that "lower coal availability also contributed to several high-priced events in New South Wales and Queensland on peak demand days, driving up average prices in those regions".[27]

The issue here is that coal generator breakdowns can come suddenly, giving market energy suppliers little to no time to prepare and respond. The scale of the difference between the expected coal plant availability versus actual availability over the 2022 crisis is interesting to note in the context of this report.

In the chart below the orange line illustrates the availability coal plant operators expected to achieve over 1 April to 10 June 2022, which averages around 85% – slightly above what Frontier Economics models for the coal capacity factor. The blue line illustrates the actual availability the coal plants achieved over this period, which was close to an average of 70%. Such a scale of differences between expected and actual availability can have very serious consequences for both electricity market prices and reliability.

[26] AER. State of the Energy Market 2023. October 2023. Page 59.
[27] AEMO. Quarterly Energy Dynamics Q4 2024. January 2025. Page 17.

Figure 7: NEM coal fleet availability Q2 2022



Source: Watt Clarity,[28] based on AEMO data.

A study by Jacobs for the Clean Energy Council provides one indication of the possible implications for consumer electricity costs from a failure to roll out renewable energy at a pace that would allow coal to be replaced on a timely basis. It found that household bills in the NEM could rise by $449 per year by 2030 if we had greater reliance on gas and coal and renewables were built more slowly. It found that household bills could rise by $606 per year by 2030 if this occurred *and* a major coal-fired power plant failed unexpectedly.[29]

Extended reliance on old power plants also poses risks to worker and community safety

When equipment fails at a coal power plant or its associated mine, it can have consequences that go well beyond just a loss of power. Coal power plants involve highly flammable fuels, very high temperatures, intense pressures, and heavy equipment moving at high speeds. The mines also are subject to fire risk and can be subject to large land slips. Therefore, when equipment becomes so old and fatigued it is unreliable or when maintenance is skimped, the end result can be explosions, fires and mine collapses that can severely injure or kill workers. There can also be serious impacts on surrounding communities. This is not a theoretical possibility; such events have occurred on multiple occasions across several NEM coal power plants where age of the plants and their likely limited future lifespan are likely to have been a contributing factor.

[28] Watt Clarity. A closer look at coal-fired generation availability. 10 June 2022.
[29] Jacobs. The Impact of a Delayed Transition on Consumer Electricity Bills. 28 February 2025. Page vii.

Below are a sample of the types of serious accidents and safety issues that have afflicted Australian coal power plants suffering from the effects of age. They serve as a warning that decisions to extend the operation of coal power stations should not be made lightly and need to be made with a thorough understanding of the condition of the power plants. More recent experience at Callide C has also been included – this experience shows that newer generators can also suffer similar challenges.

Hazelwood

Victoria. Commissioned 1964-1969

February 2014 – Mine fire

A fire began in a worked-out (disused) section of the coal mine, likely ignited by embers from nearby bushfires. The fire quickly grew to a huge scale, burned for 45 days and required the use of 7,000 emergency services personnel and around 200 firefighting appliances, including aircraft, tankers, pumpers, ladder platforms and a range of vehicles to contain and extinguish. The surrounding community was blanketed in dense smoke for much of those 45 days and it was estimated that the total cost of the fire borne by the Victorian government, the local community and the coal mine operator, ENGIE (formerly GDF Suez), exceeded $100 million.[30]

An inquiry found that in the years preceding the fire, degraded or leaking pipework was progressively removed from the fire service network in worked-out areas of the Hazelwood mine and was never replaced, nor was the area covered in sufficient soil to prevent ember ignition.[31] The operator of the Hazelwood coal mine was found guilty of 10 charges brought by WorkSafe Victoria for failing to ensure the safety of workers and the community during the mine fire.[32]

December 2016 – Boiler cracking

In 2016, documents from WorkSafe Victoria, obtained by the ABC through a freedom of information request, revealed significant safety concerns with the Hazelwood power station. The documents showed that some boilers at Hazelwood had been leaking highly pressurised steam, and corrosion and cracked welding were observed.[33]

A number of accidents and near-misses had occurred at the power station and coal mine:

- In 2016, inspectors attended the site after a burst of pressurised steam escaped from a 50cm split in a tube in one of the boilers.
- In 2015, a large piece of refractory fell six metres near two employees.
- In 2013, a 4kg bar fell from a five-metre height, landing to within five metres of an employee.
- In 2012, a worker received an electric shock while attempting to connect fluorescent lighting.

[30] Victorian Government. Hazelwood Mine Fire Inquiry Report. 3 September 2014.
[31] Ibid.
[32] WorkSafe Victoria. Hazelwood Power fined after devastating mine fire. 19 May 2020.
[33] ABC News. WorkSafe notices detail extent of repairs needed at Hazelwood power station. 1 December 2016.

WorkSafe ordered the owner of the power station Engie to complete major repairs to at least five of the eight boilers to meet occupational health and safety regulations. A few months later Engie announced it would be closing the plant.[34] Engie Australia's then-chief executive Alex Keisser explained: "Engie in Australia would need to invest many hundreds of millions of dollars to ensure viable and, most importantly, continued safe operation."[35]

Muja AB

Western Australia. Commissioned 1966

March 2012 – boiler pipe explosion

A boiler pipe in the refurbished unit 3 exploded and released a burst of steam, leading a worker to sustain burns to his legs. A union official representing the workers observed that it was extraordinary that nobody else was hurt in the incident and the lack of casualties was "a miracle".[36] A subsequent investigation of the accident revealed extensive corrosion of boiler tubes was the likely fault.[37] In response to this investigation, Western Australia's then-premier Colin Barnett told ABC News: "At this stage I can't say whether units 1 and 2 will come (back) on, the extent of the corrosion damage is so extensive, that (they are) unacceptable from a safety point of view."[38]

Yallourn

Victoria. Commissioned 1978

June 2012 – Mine flooding

The wall built to divert the Morwell River to allow an expansion of the Yallourn Coal Mine collapsed leading to large parts of the mine becoming flooded for several weeks. This subsequently required an emergency approval from Environment Protection Authority Victoria to allow the operator to dump 300 million litres per day of contaminated water into the La Trobe River to remove the floodwaters from the mine.

June 2021 – Risk of mine flood due to cracking in river diversion wall

The Morwell River diversion wall suffered significant cracking requiring workers to be evacuated from the mine in response to the risk of severe flooding if the wall was to collapse again.[39] Morwell River flows were diverted into the Hazelwood Mine and the Latrobe River to reduce the risk of further damage to the diversion wall. Works to repair the diversion wall then took 18 months to complete.[40]

[34] Engie. Hazelwood power station in Australia to close at the end of March 2017. 3 November 2016.
[35] ABC. Hazelwood power station: Closure of plant to leave hundreds jobless. 3 November 2016.
[36] Collie Mail. Man burnt in Muja Blast. 4 March 2012.
[37] ABC News. Government suspends work on Muja power station. 25 January 2013.
[38] ABC News. Millions spent on failed attempt to revive Muja power station. 19 June 2013.
[39] ABC News. Yallourn Power station evacuates mine due to potential flooding in Victoria's Latrobe Valley. 12 June 2021.
[40] Victorian Government. Yallourn Power Station – Ensuring the safety and security of Victoria's energy supply. 1 March 2023.

November 2018 – Circuit breaker arc flash explosion

A worker died from severe burns following an arc flash explosion while he was restoring a high-voltage circuit breaker. The owner of the plant subsequently pleaded guilty to three charges of failing to provide a safe working environment, with investigations finding that a panel that was supposed to protect workers form contact with an arc flash was not secured properly.[41]

According to reports in The Age, this was the third time in 18 months that a circuit breaker had exploded. Union official Geoff Dyke told the newspaper that, "the combination of an aging plant, poor maintenance and a 'disregard' for safety had led to a significantly higher rate of failures, including electrical fires and transformer explosions".[42]

March 2021 – Pulverised mill explosion and fire

A catastrophic explosion occurred in one of the pulverised fuel mills, where the casing around the pulverising mill shaft was blown apart, sparking a fire and flinging metal debris as far as 20 metres away. According to reports in The Sydney Morning Herald, workers stated it was "pure luck that no one was seriously injured or killed".[43]

As a result of the incident, WorkSafe Victoria issued the owner with an improvement notice because it had failed to conduct structural integrity tests on areas close to the explosion site, warning there was a risk loose material could fall down and "fatally injure" someone.

Morwell/Energy Brix

Victoria. Commissioned 1958-1962

December 2003 – Major briquette factory fire

Built-up coal dust in the factory spontaneously combusted in 2003. The resulting fire spread quickly through the briquette factory requiring 40 firefighting personnel and taking 20 hours to extinguish.[44] Reports on the fire noted that, "the quick-spreading fire vindicated long held safety warnings by power industry unions, concerned about maintenance amid ageing power industry infrastructure."[45]

January 2013 – fire in raw coal bunker

A fire occurred in raw coal bunker requiring 30 firefighters to extinguish over an eight-hour period.[46]

[41] ABC News. Energy Australia fined $1.5 million after 2018 workplace death at Yallourn Power Station. 13 February 2023.
[42] The Age. Power plant owner accused of disregarding safety after worker's death. 15 November 2018.
[43] Sydney Morning Herald. 'Dollars before lives': Workers hit out at Yallourn safety culture. 13 November 2021.
[44] Latrobe Valley Express. 'From ashes to action.' 22 December 2013.
[45] Latrobe Valley Express. Fiery plummet lingers. 29 December 2013.
[46] Latrobe Valley Express. Fire containment delayed. 9 January 2013.

Northern

South Australia. Commissioned 1984-85

June 2015 – Fire in coal bunker

A fire that started in a coal bunker sparked an explosion on the fifth floor of the power station. One worker sustained burns to his face and hands requiring emergency airlift to Adelaide hospital and another two firefighters suffered minor injuries. [47]

Callide C

Queensland. Commissioned 2001

May 2021– Catastrophic explosion at unit C4

In May 2021, the failure of a battery back-up system at the Callide C4 unit caused a catastrophic explosion at the Callide C Power station. The explosion left almost half a million Queensland customers without power. A report into the incident revealed that there was a failure to implement effective process safety practices when replacing and commissioning the new battery charger. The report suggested that this failure was not an isolated incident, but a symptom of the organisation's failure in valuing and implementing effective process safety practices. Under-resourcing and inadequate funding in the process safety program were noted. The report found that CS Energy was operating in a range of constraints including its status as a government-owned corporation, a joint venture ownership structure, a highly regulated energy market and facing the impacts of climate change. The report found that "these constraints influence investment and cost cutting, organisational focus, and decision making".[48]

The Queensland Mining and Energy Union district president Mitch Hughes higlighted how scary the incident would have been for workers, stating "we're talking about a 2-tonne piece of metal shaft flying across the floor and a 300-kilogram gear launched 20 metres into the air".[49] Unit C4 was offline for nearly two years due to the blast.[50]

April 2025 – Pressure Spike in boiler at unit C3

The Callide C Power Station was again damaged by a pressure spike inside the left boiler of unit C3 on 4 April 2025. A piece of hardened ash (a "clinker") detached from the internal boiler wall and fell, resulting in a 8,000 kilopascal pressure spike within the furnace, which damaged the cladding and lagging in the upper section of the boiler. The owner CS Energy warned that the unit is expected to be offline until the end of May at least. The Mining and Energy Union Queensland vice-president

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[47] ABC News. Three people including firefighters injured after explosion at power station outside Port Augusta. 7 June 2015.
[48] ABC News. Damning report into 2021 Callide C power station explosion finds CS Energy failed to implement 'effective safety practices.' 25 June 2024.
[49] Ibid.
[50] The Australian. Callide coal-fired power station shut down again. 9 April 2025.

Shane Brunker said that it was a "sheer fluke" that the blast occurred during the night shift when workers had taken a short break, otherwise "they would have been injured".[51]

Refurbishing coal power plants entails significant costs, uncertainty and risk

While there is potential to enhance the reliability of old coal power plants through investment in replacing and refurbishing components, this involves significant costs. Also while these costs per unit of capacity can on the surface appear compelling relative to building a brand new power plant, they come with extra uncertainties and risks.

The most important of these risks is that coal power plants are highly carbon-intensive. To meet emissions reduction goals, these plants need to be phased out quickly. This means investors and lenders are reluctant to finance such plants given the reasonable probability they will face regulatory interventions that constrain their output to reduce emissions.

Further, a refurbishment of a coal power plant is a complex construction project that involves a level of bespoke site-specific design. While there is the potential to save money by reusing some existing structures and equipment, this can come at the expense of extra complexity and also creates uncertainty over the build process. To some degree it's not unlike renovating an old house, once you start pulling things apart you can uncover unanticipated flaws or problems with the existing structures that mean the scope of work required is more significant than originally planned. Mixing and matching components that weren't originally designed to work together can also sometimes lead to compatibility problems.

Another issue is that, by mixing old and new, the amount of extra operating life you'll get from the investment will typically fall well short of investing in a completely new power plant.

Table 3 below summarises three historical examples of estimated or actual coal power plant refurbishment costs. The costs in 2025 real dollars for refurbishment ranged from $400 million to $1.3 billion. In all three cases the sum of money involved is a major investment for an Australian power company that would warrant detailed due diligence.

At the same time, however, the cost per unit of capacity looks quite attractive relative to buying a new plant. In the case of Hazelwood in particular it is very compelling, but even Muja AB could be a cost-competitive source of power, with a capacity factor in the realm of what most coal power plants typically achieve.

Yet the owners of Liddell and Hazelwood judged that refurbishment did not represent a sound economic investment and they elected to not proceed. In the case of Muja AB, refurbishment did go

[51] The Australian. Callide coal-fired power station shut down again. 9 April 2025.

ahead, but it was a decision the owner of the plant – the Western Australia Government – would come to regret.

Examining each of these cases, as well as the recent experience of Delta Electricity in trying to refinance its Vales Point Power Station, helps to illustrate that the major refurbishment investments needed to support a coal extension strategy would be highly challenging for private sector participants.

Table 3: Historical refurbishment cost examples

Plant	Capacity	Type of extension	Historical cost (million)	Dollar year	Inflation	2025 cost (million)	Cost per MW	Cost per kW
Muja AB	240	15-year extension: EPC for refurbishment, boiler repair, schedule overrun costs and other costs	308	2014	1.3419	413	1,722,105	1722
Hazelwood	1640	To meet safety requirements: boiler repairs and other upgrades/maintenance	At least $400	2016	1.3236	529	322,829	323
Liddell	2000	10-year extension: turbine overhaul, boilers maintenance, ash dam extension (building higher walls) and other upgrades and maintenance	980	2013	1.3636	1336	668,164	668

Sources: KPMG,[52] Worley Parsons,[53] Engie statements.[54]

Muja AB refurbishment

Western Australia's Muja Power Station's A and B generators (two of four generating units at the Muja facility) were 41 years old when in April 2007 they were initially taken out of service. A subsequent shortage of gas in Western Australia due to an explosion at the Varanus Island gas processing plant led to the decision to refurbish and recommission these plants in 2009. The saga surrounding this project serves as a clear warning of the risks that are involved in seeking to refurbish old coal power plants.

The refurbishment of Muja's A and B units was initially budgeted at $100 million and intended to be financed entirely by the private sector. However, during the attempted recommissioning process in 2012, an explosion of boiler piping injured a worker. The resultant investigation uncovered serious

[52] KPMG. Post completion review of the Muja AB Project. 6 April 2014.
[53] Worley Parsons. Macquarie generation Liddell power station study into life extension till 2032. 22 December 2013.
[54] ABC News. WorkSafe notices detail extent of repairs needed at Hazelwood power station. 1 December 2016.

corrosion of the boiler tubes, which had not been adequately inspected before the refurbishment was originally planned and budgeted.

By mid-2013, $280 million had been spent on the refurbishment and the private sector sponsor of the project had withdrawn. Then-energy minister Mike Nahan stated that when the refurbishment was originally proposed, the state utility Verve had estimated the project would deliver profits of $243 million, or 27%, over its life. However, it was now expected to return a profit over its 15-year life of just $15 million. Nahan noted that, "Verve Energy failed to undertake the necessary technical due diligence to ensure that there were no problems with the existing plant. This failure led to significant cost increases that are ultimately borne by the taxpayers."[55]

At this point the Government put the refurbishment on hold with just two of the four units operational. The Premier at the time, Colin Barnett, stated, "Whether that project [the refurbishment] is re-activated at some stage, I don't know at this point, [it's] probably fairly unlikely. As to the question of funding approval, what Cabinet has decided is that no more public money will go into this project."[56]

However, after receiving further advice indicating that revenues would exceed an additional $45 million needed to complete refurbishment, the State Government recommenced the project in September 2013.[57] Nahan defended the decision by arguing that the 15-year expected lifetime of the refurbished plant would allow sufficient time to recoup a profit from the extra expenditure.[58]

Yet even after the refurbishment was complete, according to the West Australian newspaper the plant, "was plagued by operational and reliability problems, generating electricity just 20 per cent of the time".[59] In 2017, the decision was made to shut down Muja A and B just three years after they'd been refurbished and 12 years short of the 15-year life that was originally expected.[60] The final cost of the refurbishment was $308 million, three times the original budget.

Liddell refurbishment

In 2013, Worley Parsons found the cost to extend Liddell from 2022 to 2032 was $980 million, including costs to overhaul turbines, maintain boilers, raise the height of the walls of the ash dam, and other upgrades and maintenance.[61] Adjusting for inflation since then gives a cost in 2025 dollars of $1.34 billion or $668 per kilowatt (kW). While the cost per kilowatt of capacity realised from such a refurbishment appears attractive relative to new build, it should be noted that it was only expected to deliver a 10-year life. In addition, the power plant would also face a substantial fuel costs in paying for coal.

[55] The West Australian. Dud powerhouse burns up $280m. 28 June 2013.
[56] ABC News. Government suspends work on Muja power station. 25 June 2013.
[57] Utility Magazine. Government plans to refurbish Muja Power Station. 26 September 2013.
[58] ABC News. Muja power station will return to profit despite cost blowout, WA Government says. 10 April 2014.
[59] The West Australian. Muja AB closure to cost $20m. 27 March 2018.
[60] The West Australian. Collie's Muja AB power station to close in multi-million dollar loss.14 September 2017.
[61] Worley Parsons. Macquarie generation Liddell power station study into life extension till 2032. 22 December 2013.

In its 2017 evaluation of whether to close or extend the operation of Liddell, AGL found that refurbishment and maintenance were likely to be a higher-cost option than building new capacity. Building new renewable energy, dispatchable energy and upgrading the efficiency of the Bayswater plant in NSW was costed at $83/MWh, while extending Liddell was costed at $106/MWh.[62]

Hazelwood refurbishment

The owner of Hazelwood, Engie, has never released a detailed costing to undertake a full refurbishment of the plant. Instead it only nominated what we suspect should only be considered as a rough ballpark estimate of the cost it would incur to fix a range of significant safety issues identified by WorkSafe Victoria, which primarily related to cracking, corrosion and general fatigue of boiler equipment. According to ABC reporting, Engie stated it would cost "at least $400 million" to revamp the power station.[63] Other statements made by Engie staff tend to be even less precise, describing the need to spend "many hundreds of millions of dollars" on upgrades in order for the plant to operate beyond 2017.[64]

In statements made to a 2022 Victorian Parliamentary Inquiry by the then chief executive of Engie Australia, Augustin Honorat, it is apparent that management felt the plant was so old and so carbon-intensive that a significant investment in extending its lifetime was probably not seriously considered.[65] Honorat told the Committee:

> *"Our decision to close the Hazelwood power station was determined by three conditions which had progressively developed and came together in 2016, about six years ago.*
>
> *"Operationally, after more than 50 years the plant was working beyond its design life. It was commissioned in 1964, and its operational life was extended multiple times by the SEC and by private operators to a point where it was no longer possible to replace or refurbish the plant's critical systems to keep it operating, let alone operating safely.*
>
> *"Economically, Hazelwood required hundreds of millions of dollars in upgrades to continue operating safely, and this capital would have had to be deployed in a chronically oversupplied and low-price wholesale environment at the time, where the prospect of any economic return was very unlikely.*
>
> *"Strategically, the Engie Group committed to exiting its interests in coal generation worldwide, viewing the environmental, social and economic costs of coal as too high. Engie at that time set a new direction to enable the transition to decarbonisation for our customers, which is a strategy that we continue to progress today in Australia, in the region and worldwide."*

[62] AGL. Investor Day Presentation. 13 December 2017.
[63] ABC News. WorkSafe notices detail extent of repairs needed at Hazelwood power station. 1 December 2016.
[64] Engie. Hazelwood power station in Australia to close at the end of March 2017. 3 November 2016.
[65] Victorian Parliament, Legislative Council, Economy and Infrastructure Committee. Inquiry into the closure of the Hazelwood and Yallourn Power Stations. June 2022. Pages 12-13.

The interesting aspect about the Hazelwood Power Station was that in the years preceding its closure its availability and cost-competitiveness were reasonably good. However, given the results of the WorkSafe inspections it was probably skirting close to the limits of what was prudent. In the end we suspect Hazelwood reflects a case where a plant is so old and carbon-intensive it reaches a point of no return, where senior management treat the plant as if it is in a state of palliative care.

Bankers' allergy to coal – the case of Vales Point

In addition to issues around the risk and commercial and operational feasibility of coal plant life extensions, owners of coal power plants are likely to face considerable difficulty raising finance to undertake such refurbishment.

Delta Electricity, the owner of the Vales Point B coal power station, revealed in a rule change request to the Australian Energy Market Commission (AEMC) that it was facing significant difficulty accessing bank finance stating, "A significant number of financial institutions… are no longer providing financing facilities to fossil fuel generators."[66]

The rule change request asked that Delta be able to provide cash, rather than a bank guarantee, to AEMO to meet prudential requirements for trading purposes. It explained that the bank providing its current guarantee was unwilling to continue with this arrangement because lending to a coal generator was in breach of environmental policies governing its financing practices. In a search to find another lender Delta found:

> *"… during the refinancing process that 13 of the 15 lenders declined due to ESG [Environment, Social and Governance] constraints, which included the Big-4 Australian banks. Both of the remaining financial institutions were prepared to offer a bank guarantee facility to provide credit support related only to requirements for mining rehabilitation obligations and renewable Power Purchase Agreements."*

The reality here is that bankers are doing exactly what their shareholders want, which is judiciously managing commercial risks. While Australia is a long way from a bipartisan consensus on climate change policy, a range of state and federal governments have introduced policies over the past two decades that have supported the growth of renewable energy. Curtailment in the output and revenues of coal fired generators has been observed as renewable energy grows, and the financial viability of coal generators has been reduced in some cases.

Given this historical reality and the fact that achievement of the Paris Agreement Climate Goals is inconceivable without a rapid phase-out of coal generators, banks could face commercial and reputational risks if they choose to finance the extension of coal power plant lifespans.

[66] Delta Electricity. Rule Change Proposal – Allowing AEMO to accept cash as credit support. 1 October 2024.

Delayed nuclear entry could exacerbate coal extension risks

The risks associated with coal extension could be exacerbated if the generation technology chosen to replace coal cannot be installed in the required timeline. This is of greater concern if the generation technology chosen to replace coal has long and uncertain lead times – as is the case with nuclear power. The average time overrun for the four most recent US and European nuclear projects, which commenced construction in the past 20 years, is 11 years.

- **Olkiluoto 3 in Finland** was originally due to start up in 2009. However, commercial operations began in 2023 (representing 18 years construction time).[67,68] This was 14 years behind schedule – due to technical delays, legal disputes and cost overruns.
- **Flamanville 3** in France was initially due to be completed in 2012.[69] However it was connected to the grid in December 2024.[70] This is a time overrun of 12 years.
- **Hinkley Point C** in the UK was expected by the CEO of EDF UK to be "cooking Christmas turkeys" in England by 2017.[71,72,73] It is now expected by EDF to open in 2030 in a base case scenario.[74] This is a time overrun of 13 years.
- **At Vogtle** in the US, two new reactors were constructed, originally expected to be in service by 2017.[75,76] However, commercial operation of each Vogtle unit was achieved by 2023 and 2024 – six or seven years later than expected.[77]

In the Frontier Economics modelling, nuclear enters the Australian system from 2036 onwards. However, if it also experienced an 11-year time overrun typical of the historical experience, nuclear would start entering the system from 2047 onwards. For nuclear to enter the system in 2047 (in 22 years) rather than from 2036 (in 11 years) would be more aligned with other evidence.

To construct a nuclear reactor, various steps need to be taken, including overturning state and federal legislation, building a nuclear power regulatory regime, developing or procuring nuclear capability, project scoping, pre-construction (planning, approvals, financing), and construction (which we have found has taken 10-18 years from historical experience[78]).

[67] Power Technology. Olkiluoto 3 Nuclear Power Plant, Finland. 8 March 2024.
[68] International Atomic Energy Agency (IAEA). Olkiluoto 3. Accessed August 2024.
[69] NucNet. Long-Delayed Flamanville-3 Nuclear Plant In France Connected To National Grid, EDF Announces. 23 December 2024.
[70] EDF. Update on the Flamanville EPR: the reactor produces its first electrons on the national electricity grid. 21 December 2024.
[71] University of Sussex. Will we ever be cooking Christmas turkeys from Hinkley C? 20 November 2014.
[72] Beyond Nuclear International. What a turkey. 31 January 2024.
[73] RenewEconomy. French nuclear giant scraps SMR plans due to soaring costs, will start over. 2 July 2024.
[74] EDF. 2024 Half Year Results. July 2024.
[75] IEEFA. Southern Company's Troubled Vogtle Nuclear Project. 1 January 2022.
[76] GPB. A second new nuclear reactor is completed in Georgia. The carbon-free power comes at a high price. 29 April 2024.
[77] Ibid.
[78] IEEFA. Nuclear in Australia Would Increase Household Power Bills. September 2024.

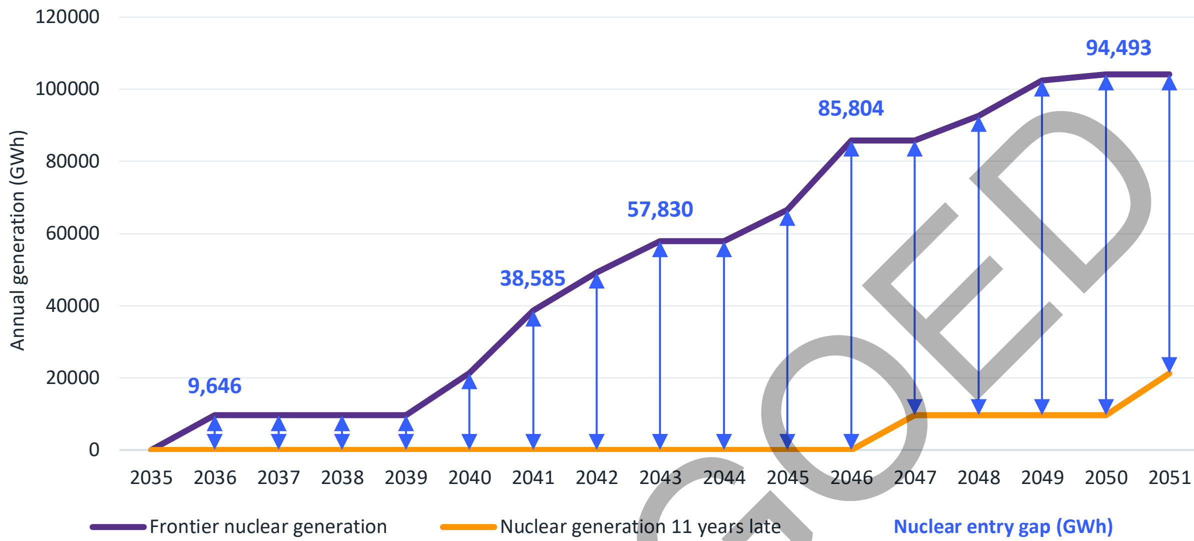
- The Clean Energy Council notes that the average time from scoping to nuclear power station connection for recent projects is 21 years (excluding time to overturn bans and build the nuclear regulatory regime).[79]
- Professor Hugh Durrant-Whyte, NSW chief scientist and a nuclear engineer with experience in the UK's nuclear industry, told an NSW inquiry in 2020 that it would be naive to think a power plant could be built in less than two decades.[80]
- CSIRO's GenCost report outlined that the nuclear lead time, which includes pre-construction activities and the construction period, would be at least 15 years (excluding time to overturn bans and build a regulatory regime).[81]
- Independent experts provided evidence at an Australian parliamentary inquiry into nuclear power generation in Australia that it would take at least 15 years to build a single reactor, and possibly as long as 25 years.[82]

If nuclear generation followed the same annual generation growth as outlined in the Frontier Economics Report 2 but 11 years later than expected, there would be a potential energy supply gap of 9,600GWh to 94,500GWh per year. This is a substantial gap. To fill it would require either *further* life extensions to coal, compounding the aforementioned risks associated with life extension, or it would require an increase in other electricity generation sources.

As new electricity generators would not have a strong incentive to invest for the long term given the planned introduction of nuclear power, it could create a "dead zone" for investment, making it challenging to secure energy supply in this period between coal exit and nuclear entry.

[79] Clean Energy Council. Analysis of Frontier's Second Report on Costs of Nuclear Power for Australia. December 2024. Page 6.
[80] Sky News. 'Will be starting from scratch': Report paints grim picture of Australia's long road to nuclear power. 10 March 2024.
[81] CSIRO. GenCost 2024-25. December 2024. Page x. "The development lead time includes the construction period plus all of the preconstruction activities such as planning, permitting and financing. Many stakeholders have agreed with the GenCost estimate of at least 15 years lead time for nuclear generation"
[82] RenewEconomy. Too slow and too expensive: House committee says Coalition nuclear plan won't help climate targets. 26 February 2025.

Figure 8: Frontier Economics nuclear generation schedule vs nuclear generation 11 years late, typical of historical schedule overrun



Source: IEEFA analysis based on interpretation of Frontier Economics Report 2 and historical nuclear project schedule overruns across Olkiluoto 3, Flamanville 3, Hinkley Point C, Vogtle Units 3 & 4 (11 years average). Note: A chart scraping tool has been used to obtain the data from Frontier Economics Report 2 so the Frontier figures are approximate.

Conclusion

Extending the reliance on ageing coal power plants in the NEM has a range of associated risks and costs. The existing generators in the NEM, at 38 years old on average, are already close to the historical retirement age of 42 years. By 2030, almost two thirds of current operating NEM coal capacity will exceed the average retirement age of past Australian coal plant that have closed.

The coal power plants that have historically closed in the NEM experienced low levels of availability in the years proceeding exit. Like the closed power stations, the existing coal power stations are likely to experience increasing numbers of outages, and therefore low availability to the market in the coming years as they near retirement.

Relying more heavily on ageing coal generators for longer can therefore raise risks to reliability. Older coal generators cannot always be relied upon to deliver energy as expected, so there is potential that the market could experience electricity supply gaps.

Keeping ageing coal power stations in the system for longer could also deliver spikes in wholesale power prices when coal outages are experienced, and other more expensive forms of generation need to step in to fill the gap.

A safety risk is also present with ageing generators. As power plant equipment ages it becomes more prone to catastrophic failures that lead to dangerous accidents, posing risks to worker and community safety.

Further, the costs involved in refurbishing coal power plants to keep them running for longer can be very high and entail significant uncertainty and risk for the operators. There is also a looming question of whether or not coal operators will be able to access finance to support continued operation and potential refurbishment of their ageing, emissions-intensive assets in a world with an increasing focus on emissions.

All these risks and costs are exacerbated if the generation technology chosen to replace coal power plants is delayed in coming online, meaning the coal power plants need to be extended for even longer into their older age.

Extending the life of coal power stations in the NEM carries a number of risks and costs that need to be considered by governments, energy planners, policymakers, regulators and operators.

Appendix

Table 4: Existing coal-fired power plants data by unit

Region	Site Name	DUID	Nameplate Capacity (MW)	Expected Closure Year	Commission date	Age now (2025)
NSW	Bayswater	BW01	660	2033	1983	42
NSW	Bayswater	BW02	685	2033	1983	42
NSW	Bayswater	BW03	685	2033	1983	42
NSW	Bayswater	BW04	685	2033	1983	42
QLD	Callide B	CALL_B_1	350	2028	1989	36
QLD	Callide B	CALL_B_2	350	2028	1989	36
QLD	Callide C	CPP_3	424	2051	2001	24
QLD	Callide C	CPP_4	420	2051	2001	24
NSW	Eraring	ER01	720	2027	1983	42
NSW	Eraring	ER02	720	2027	1983	42
NSW	Eraring	ER03	720	2027	1983	42
NSW	Eraring	ER04	720	2027	1983	42
QLD	Gladstone	GSTONE1	280	2035	1980	45
QLD	Gladstone	GSTONE2	280	2035	1980	45
QLD	Gladstone	GSTONE3	280	2035	1980	45
QLD	Gladstone	GSTONE4	280	2035	1980	45
QLD	Gladstone	GSTONE5	280	2035	1980	45
QLD	Gladstone	GSTONE6	280	2035	1980	45
QLD	Kogan Creek	KPP_1	744	2042	2007	18
VIC	Loy Yang A Power Station	LYA1	560	2035	1984	41
VIC	Loy Yang A Power Station	LYA2	530	2035	1984	41
VIC	Loy Yang A Power Station	LYA3	560	2035	1987	38
VIC	Loy Yang A Power Station	LYA4	560	2035	1987	38
VIC	Loy Yang B	LOYYB1	580	2047	1993	32
VIC	Loy Yang B	LOYYB2	580	2047	1996	29
QLD	Millmerran Power Plant	MPP_1	426	2051	2002	23
QLD	Millmerran Power Plant	MPP_2	426	2051	2002	23
NSW	Mt Piper	MP2	660	2040	1992	33
NSW	Mt Piper	MP1	730	2040	1993	32
QLD	Stanwell	STAN-1	365	2043	1995	30
QLD	Stanwell	STAN-2	365	2044	1995	30
QLD	Stanwell	STAN-3	365	2045	1995	30
QLD	Stanwell	STAN-4	365	2046	1995	30
QLD	Tarong	TARONG#1	350	2036	1985	40
QLD	Tarong	TARONG#2	350	2036	1985	40
QLD	Tarong	TARONG#3	350	2037	1985	40
QLD	Tarong	TARONG#4	350	2037	1985	40
QLD	Tarong North	TNPS1	450	2037	2002	23

NSW	Vales Point B	VP5	660	2033	1978	47
NSW	Vales Point B	VP6	660	2033	1978	47
VIC	Yallourn W	YWPS1	350	2028	1973	52
VIC	Yallourn W	YWPS2	350	2028	1975	50
VIC	Yallourn W	YWPS3	375	2028	1981	44
VIC	Yallourn W	YWPS4	375	2028	1982	43

Sources: AEMO.[83,84] Commission dates: company websites, GEM,[85] University of Melbourne,[86] Leading Edge Energy.[87]

Table 5: Existing coal-fired power plants data by power station

Region	Site Name	Nameplate Capacity (MW)	Average of Commission date	Average of Expected Closure Year (announced)	Average of Age now
NSW	Bayswater	2715	1983	2033	42
	Eraring	2880	1983	2027	42
	Mt Piper	1390	1993	2040	33
	Vales Point B	1320	1978	2033	47
	NSW Total	8305		NSW Average	41
QLD	Callide B	700	1989	2028	36
	Callide C	844	2001	2051	24
	Gladstone	1680	1980	2035	45
	Kogan Creek	744	2007	2042	18
	Millmerran Power Plant	852	2002	2051	23
	Stanwell	1460	1995	2045	30
	Tarong	1400	1985	2037	40
	Tarong North	450	2002	2037	23
	QLD Total	8130		QLD Average	34
VIC	Loy Yang A Power Station	2210	1986	2035	40
	Loy Yang B	1160	1995	2047	31
	Yallourn W	1450	1978	2028	47
	VIC Total			VIC Average	41
NEM Total		21255		NEM Average	38

Sources: AEMO.[88,89] Commission dates: company websites, GEM,[90] University of Melbourne,[91] Leading Edge Energy.[92]

[83] AEMO. NEM Generation Information. January 2025.
[84] AEMO. Generating Unit Expected Closure Year. January 2025.
[85] GEM. Global Coal Plant Tracker. Accessed February and March 2025.
[86] Climate Energy College, University of Melbourne. Retirement of coal fired power stations. 10 November 2016. *Dylan McConnell*.
[87] Leading Edge Energy. The timeline for coal exit in Australia's power generation fleet. Accessed February 2025.
[88] AEMO. NEM Generation Information. January 2025.
[89] AEMO. Generating Unit Expected Closure Year. January 2025.
[90] GEM. Global Coal Plant Tracker. Accessed February and March 2025.
[91] Climate Energy College, University of Melbourne. Retirement of coal fired power stations. 10 November 2016. *Dylan McConnell*.
[92] Leading Edge Energy. The timeline for coal exit in Australia's power generation fleet. Accessed February 2025.

Table 6: Closed power stations

State	Name of power plant	Capacity	Commissioning year of units	Closure Year	Age of units at closure (years)	Average age of units when closed (years)
QLD	Swanbank A	396	1966-1969	2002	33-36	35
	Swanbank B	480	1970-1973	2012	39-42	41
	Collinsville	190	1968-1974	2012	38-44	41
	Callide A	120	1965	2016	51	51
NSW	Munmorah	600	1969	2012	43	43
	Redbank	150	2000	2014	14	14
	Wallerawang C	1000	1976	2014	38	38
	Liddell	2000	1972	2023	38	51
VIC	Morwell	195	1958-1962	2014	52-56	54
	Anglesea	160	1969	2015	46	46
	Hazelwood	1640	1964-1969	2017	48-53	51
SA	Northern	530	1984-1985	2016	31-32	32
	Playford	240	1963	2016	53	53
Total		7701				42

Sources: ACIL Allen,[93] company websites, GEM,[94] Wikipedia,[95,96] The Courier Mail,[97] Clean Energy Finance Corporation (CEFC).[98]
Note: When we have different commissioning years or closure dates across units, the figures in the table are averaged.

Availability of closed power stations

Availability factors were calculated using AEMO available generation data (as generated) and dividing it by the nameplate capacity of the generating unit over every 30-minute period. The average of the past 10 years for the units at each shuttered coal power plant was then taken (shown below). Then the NEM-wide average has been taken across all coal power stations.

Nameplate capacity figures were sourced from AEMO Generation Information January 2025, or for earlier generators from a 2009 ACIL Allen calculation of energy costs report.[99] Two nameplate capacity figures were sourced from Wikipedia.[100,101]

When calculating the average availability in the 10 years prior to exit, we mostly excluded the final year or two before exit, because the plant is in the process of exiting and usually has very low

[93] ACIL Allen. The calculation of energy costs in the BRCI for 2010-1. 14 December 2009.
[94] GEM. Global Coal Plant Tracker. Accessed February and March 2025.
[95] Wikipedia. Callide Power Station. Accessed March 2025.
[96] Wikipedia. Swanbank Power Station. Accessed March 2025.
[97] Courier Mail. Shutdown at Swanbank B. 25 May 2012.
[98] CEFC. Collinsville Solar Farm transforms former power station site. Accessed 6 March 2025.
[99] ACIL Allen. The calculation of energy costs in the BRCI for 2010-1. 14 December 2009.
[100] Wikipedia. Callide Power Station. Accessed March 2025.
[101] Wikipedia. Swanbank Power Station. Accessed March 2025.

availability, which may not be representative of what it is capable of. Further, availability data was not available for 2000; when the data was not available it was excluded from the 10-year period.

Table 7: Availability of closed power stations 10 years before exit

State	Power plant	Availability 10 years before exit	10-year period
QLD	Swanbank A	n.a.	n.a. due to insufficient data
	Swanbank B	80%	2000-2009 inclusive
	Collinsville	54%	2002-2011 inclusive
	Callide A	n.a.	n.a. due to insufficient data
NSW	Munmorah	33%	2000-2009 inclusive
	Redbank	80%	Q3 2005 - Q3 2014 inclusive
	Wallerawang C	78%	2004-2013 inclusive
	Liddell	54%	2013-2022 inclusive
VIC	Morwell	68%	2003-2012 inclusive
	Anglesea	90%	Q3 2005-Q2 2015 inclusive
	Hazelwood	81%	2007-2016 inclusive
SA	Northern	80%	2006-2015 inclusive
	Playford	25%	2002-2011 inclusive
Average		66%	

Source: IEEFA analysis of AEMO data.

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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