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Future Australian Electricity Generation Costs

- A Review of CSIRO's GenCost 2021-22 Report

David Carland

Australian Resources Development Pty Ltd

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Key Points

- **This Paper contradicts the findings of CSIRO that integrated wind and solar are the 'cheapest' new generation technologies in Australia.**
- **Australian policy makers and stakeholders need to be fully informed of the likely future costs of the energy transition.**
- **An urgent, in-depth review of the CSIRO's findings is recommended.**

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Executive Summary

In Australia, CSIRO and the Australian Energy Market Operator (**AEMO**) undertake an annual process of calculating and publishing estimated costs of building a range of new electricity generation and storage technologies (**New-build Approach**). The process is known as the GenCost Project. Its most recent iteration in July 2022 is referred to in this Paper as **GenCost22.**

There is now widespread support to move the world towards a decarbonised energy economy. In the **NetZero2050** era in Australia, the significance of the GenCost22 findings cannot be overstated. The GenCost22 findings are, as CSIRO states, 'highly impactful' on Australian electricity market modelling studies, which are, in turn, required by governments and regulators to assess alternative policies and regulations. The findings also influence public debate on a decarbonised energy economy. In this context, GenCost22 has a critical role to inform policy makers and the public of the cost trade-offs of replacing fossil-fueled technologies.

Based on GenCost22, CSIRO's major conclusion is "… that wind and solar are the cheapest source of electricity generation and storage in Australia, even when considering additional integration costs arising due to the variable output of renewables, such as energy storage and transmission." Based on this conclusion, policy makers could easily assume that the transition to low-carbon energy will lower the cost to consumers of a reliable electricity supply.

There are, however, a number of major unresolved issues over the estimated costs of integrating 'variable renewable energy' (**VRE**) technologies with the other non-renewable technologies in Australia's future power system.

This Paper documents the outcome of a critical analysis of GenCost22. This analysis has identified major deficiencies and omissions with the GenCost22 data assumptions including:

- Assumed capacity factors for VRE technologies that significantly exceed capacity factors currently observed in the market.
- Assumed capacity factors for baseload technologies that are significantly lower than the technical capabilities of new-build plant.
- A failure to take account of connection costs and marginal loss factors which are relatively high for VRE technologies.
- Outdated and significantly overstated capital cost estimates for nuclear small modular reactors.

This analysis has also identified the significant underestimation of the cost of integrating, or firming, VRE technologies to achieve a reliable system including:

- Failing to attribute any cost to the currently installed firming capacity which is inconsistent with the New-build Approach and the current pressure on system reliability and the high market prices.
- Projecting a reliable system in the same time period that AEMO is predicting major capacity shortfalls, with similar technology mixes, lower VRE penetration and more firming capacity.
- The inconsistency with an earlier, detailed CSIRO study which sought to ensure that the system was robust during weather droughts when VRE resources remain absent or low for long periods.

GenCost22 estimated VRE integration costs of \$16/MWh - \$28/MWh as the VRE Share increases from 60% to 90%.

When adjustments are made for the factors outlined above, the estimated average integration costs are $44/MWh - $111/MWh at current costs and $22/MWh - $54/MWh at the FY2030 assumptions. The lower integration cost estimates using the FY2030 assumptions requires the achievement of a rapid reduction in the unit cost of VRE technologies and firming capacity.

Applying these adjusted firming costs, the recalculated LCOEs[1], set out in Table E.1, contradict the GenCost22 conclusion that integrated wind and solar are the "cheapest" new generation technologies. They also indicate that the cost of Australia moving to a predominantly renewables power system has been materially underestimated.

Table E.1: Results of Comparative Analysis of LCOEs in FY2030

Source	**GenCost22[1]**	**Amended[2]**	**Amended[3]**
Cost Base	**FY2030 Assumptions**	**FY2021 Current**	**FY2030 Assumptions**
Technology			
Black coal	$97	$80	$82
Gas CCGT	$119	$105	$108
GT small	$210	$137	$143
GT large	$191	$138	$143
Black coal - CCS	$176	$151	$114
Nuclear (SMR)	$218	NA	$71
Unfirmed - standalone			
LS[4] Solar PV	$38	$77	$48
Wind onshore	$48	$74	$69
Firmed – integrated 67%[5] VRE Share			
LS Solar PV	$54	$129	$73
Wind onshore	$64	$112	$88
Firmed – integrated 92%[5] VRE Share			
LS Solar PV	$66	$207	$112
Wind onshore	$76	$169	$116

1. Applying the GenCost22 FY2030 assumptions to the GenCost22 firming requirements in FY2030.
2. Applying the current FY2021 costs to the amended firming requirements in FY2030.
3. Applying the amended FY2030 assumptions to the amended firming requirements in FY2030.
4. Large-scale or utility-scale solar PV.
5. VRE share of total generation, adjusted from 60% and 90% respectively by including rooftop solar PV as VRE.

Based on current costs, the integrated VRE technologies are significantly more expensive than baseload thermal technologies for all the VRE shares analysed.

[1] Levelised costs of electricity.

Using the FY2030 cost assumptions, the VRE technologies are not the cheapest new generation technologies, being more expensive than SMRs in all cases and more expensive than black coal except for large-scale Solar PV at the lowest VRE share. Again, the improvement in the competitive position of the VRE technologies requires the achievement of the assumed rapid reduction in the unit cost of VRE technologies and Firming Capacity.

These amendments to the GenCost22 findings do not mean that the transition to a low carbon energy sector is not important and worthwhile.

However, the analysis of the GenCost22 findings in this Paper has highlighted the importance of Australian policy makers and stakeholders being better and more reliably informed of the likely future costs of making the transition to a low carbon generation sector. For that purpose, an urgent, in-depth review of the GenCost22 findings and their implications is recommended.

1. Introduction

1.1 Background

In Australia, CSIRO and the Australian Energy Market Operator (**AEMO**) undertake an annual process of calculating and publishing costs of building a range of new electricity generation and storage technologies (**New-build Approach** or **New-build Methodology**).

Its most recent iteration in July 2022 is "GenCost 2021-22 Final report" (**GenCost22)**.

There is now widespread support to move the world towards a decarbonised energy economy. In the NetZero2050 era in Australia, the significance of the GenCost22 findings cannot, therefore, be overstated.

The GenCost22 findings are, as CSIRO states, 'highly impactful' on Australian electricity market modelling studies, which are in turn required by governments and regulators to assess alternative policies and regulations. The GenCost22 findings, as CSIRO further states, are required by governments and regulators to assess alternative policies and regulations. (Page10).

Thus, the GenCost22 findings influence public debate on a decarbonised energy economy. In this context, GenCost22 has a critical role to inform policy makers and the public of the cost trade-offs of replacing fossil-fueled technologies with integrated renewable.

GenCost22 applies updated current capital cost estimates, commissioned by AEMO and delivered by Aurecon, to produce projections of future changes in costs, consistent with updated global electricity scenarios which incorporate different levels of achievement of global climate policy ambition. Levelised costs of electricity (**LCOEs**) are also included and provide a summary of the relative competitiveness of generation technologies.

LCOE calculation converts all costs into annual operating costs (i.e., capital costs are amortised into equivalent annual payments using a 5.99% discount rate), divides by annual generation and adds variable costs to produce a unit cost as $/MWh.

GenCost22 assumes a rapid reduction in the capital cost of variable renewable energy (**VRE**) technologies. Technology learning rates are an important input into the cost assumptions and VRE technologies are assessed as having high learning rates resulting in very optimistic, assumed cost reductions.

In contrast, very high capital costs are assumed for low carbon, dispatchable (**LCD)** technologies such as coal and gas-fired generation technologies with carbon capture and storage (**CCS**) and nuclear small, modular reactors (**SMRs**). These technologies are much denser sources of energy than integrated VRE and their development is consistent with meeting the current carbon dioxide emissions policy settings.

In the case of generation technologies with CCS, GenCost22 attributes a major reason for the high costs to the relative maturity of the generation technologies linked to CCS. Mature technologies are associated with declining learning rates.

In the case of SMRs, GenCost22 does not report the current costs of SMRs but costs from FY2030 "… reflecting the fact that no Australian SMR project is likely to be deployed before this date." (Page 15). The post-2030 costs are high because of concerns about the global rate of deployment linked to financing, safety and competing lower cost technologies.

In addition to accounting for the direct costs of VRE technologies, the GenCost22 LCOEs also include the impact of the costs incurred to “integrate” the VRE into the system to enable an accurate comparison between the estimated LCOEs of firmed VRE and the baseload technologies. The cost of integrating the VRE technologies, commonly referred to as firming, is estimated for VRE shares of total generation **(VRE Share**) ranging from 60% to 90% by FY2030.

Analysis indicates these firming costs are underestimated.

1.2 GenCost22 Results

This Paper focusses on the results for fiscal year (**FY**) 2021 and FY2030. GenCost22 LCOE estimates for a range of generation technologies are set out in Table 1.1 for those years.

The estimates in the Table differ from those published in Appendix Table B.9 (page 76) due to the following factors:

- The use of the averages of the Gencost22 high and low assumptions for capital cost, capacity factor and heat rate for each relevant technology.
- The results for 60% and 90% VRE Shares only.
- The integration costs of $16/MWh for a 60% VRE Share and $28/MWh for a 90% VRE Share (page 57) that GenCost22 applies to the unfirmed LCOEs of combined wind and large-scale solar PV are applied individually to the unfirmed wind and solar PV LCOEs.

Table 1.1: GenCost22 published LCOEs

Technology		**FY21**	**FY30**
		$/MWh	**$/MWh**
Black coal		$93	$97
Gas CCGT		$107	$119
Gas turbine small		$195	$210
Gas turbine large		$177	$191
Black coal with CCS		$172	$176
Nuclear (SMR)		NA	$218
Unfirmed – standalone VRE			
Large-scale (LS) Solar PV		$53	$38
Wind onshore		$54	$48
Firmed – integrated VRE			
LS Solar PV	60% VRE Share	NA	$54
Wind onshore		NA	$64
LS Solar PV	90% VRE Share	NA	$66
Wind onshore		NA	$76

The relevant comparison[2] is with the estimated LCOEs for integrated VRE technologies which are significantly lower than estimated LCOEs for the thermal and LCD technologies.

Major conclusions from the GenCost22 results are:

- The wide differential in the assumed capital costs and the low cost of firming is reflected in the LCOEs across the various technologies.
- The LCOEs for the LCD technologies are the highest of all the technologies by a significant margin.
- The significant reduction in the VRE LCOE between FY2021 and FY2030 is the result of the assumed rapid decrease in the unit costs, especially for LS Solar PV.

It is noted that approximately 57% to 65% of the integration costs are accounted for by the expansion of transmission infrastructure from renewable energy zones and other transmission additions as the VRE Share increases from 60% to 90% (page 56). Thus, the total integration cost estimates can be restated as follows:

- Firming Capacity - $7/MWh to $10/MWh as the VRE Share increases from 60% to 90%.
- Transmission expansions - $9/MWh to $18/MWh as the as the VRE Share increases from 60% to 90%.

Gencost22 concludes:

"The analysis confirms that when integration costs are included variable renewables remain the lowest cost new-build technology." (Page 57).

Consistent with these outcomes, Treasurer Chalmers was quoted in June as follows: "The reason that I am not keen on nuclear energy for Australia is because the economics don't stack up…" (SkyNews, 8 June 2022).

Further, the CSIRO media release accompanying the release of GenCost22 in July 2022 states:

"The 2021-22 report confirms past years' findings that wind and solar are the cheapest source of electricity generation and storage in Australia, even when considering additional integration costs arising due to the variable output of renewables, such as energy storage and transmission."

2. Purpose

Given the importance of GenCost22, the purpose of this Paper is twofold:

6. To evaluate the impact on the estimated LCOEs of the LCDs and other technologies of updating the GenCost22 assumptions based on the assumptions of the "2022 AEMO Integrated System Plan, 30 June 2022" (**ISP22**) and capital cost estimates of LCDs drawn from international agencies and current international projects.
7. To evaluate the impact on the estimated LCOEs of applying the amount and resultant cost of the firming capacity required to firm the VRE technologies derived from other studies by AEMO and CSIRO, especially CSIRO's "Low Emissions Technology Roadmap", June 2017 (**CSIRO 2017 Roadmap**).

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[2] As noted by GenCost22 (page 53), the estimates of the unfirmed VRE LCOEs are not directly comparable with the electricity from the thermal and LCD technologies which are dispatchable while the electricity from the VRE technologies is intermittent.

3. Review of the data assumptions

3.1 Background

The primary purpose of GenCost22 is to use current and future estimates of capital and other costs to calculate the estimated LCOEs to provide a summary of the relative competitiveness of a range of new-build generation technologies.

The estimates of electricity generation and storage costs, performance characteristics and other relevant parameters are drawn from estimates prepared by Aurecon on behalf of AEMO.

This Section provides an analysis of the GenCost22 data assumptions for various generation technologies and the selection of the discount rate.

3.2 Data assumptions for thermal and VRE technologies

The data used by GenCost22 and ISP22 are reproduced in Appendix 1 for several generation technologies. GenCost22 notes that its data is "… consistent with AEMO ISP data sets…" (page 55).

A comparative analysis of the data assumptions (excluding the assumptions for LCDs which are reviewed in Section 3.3 and for capacity factors (**CFs**), connection costs and marginal loss factors (**MLFs**) which are reviewed in Section 4.1) indicates the following:

- GenCost22 capital costs are universally lower for all technologies.
- GenCost22 heat rates are lower for all thermal technologies, except black coal.
- GenCost22 fuel costs are universally higher for the thermal technologies.
- The fixed operating and maintenance costs are generally similar as are the variable operating and maintenance costs except that GenCost22 has a much higher assumption for small gas turbines and ISP22 has a much lower assumption for large gas turbines.

A major feature of theFY2030 cost assumptions for both GenCost22 and ISP22 is the assumed rapid reduction in the unit costs of LS Solar PV and battery storage (8 hours) of 48% and 58% respectively (based on ISP22). These assumed cost reductions compare with 8% for wind (onshore) and 2 – 3% for other thermal technologies.

3.3 Data assumptions for LCD technologies

Nuclear SMRs

Table B.8 of GenCost22 lists the cost of nuclear SMR in FY2030 as $7,904/kW in the low case assumption and $16,773/kW in the high case assumption.

The high case assumption is based on the 2018 GHD nuclear cost review for CSIRO which provided a figure of $16,000/kW for an SMR for the GenCost 2018 report. The 2015 International Energy Agency (**IEA**) and Nuclear Energy Association report (**IEA2015**) "Projected Costs of Generating Electricity" includes a statement "… the specific per-MW costs of SMRs are likely to be higher (typically 50% - 100% higher per kWe for a single SMR plant) than those of large generation III reactors". (Page 159). This statement was used to justify the increase of the $8,000/kW cost of a large reactor to $16,000/kW. GenCost22 continues to quote IEA2015 as the justification for the 100% increase for Australia "… reflecting our limited experience in nuclear generation…" (page 14).

This was supported by a 2019 study for the Canadian Nuclear (**CNA2019**) which GenCost22 lists as the "most recently available" (page 17) data source for SMRs.

The low assumption is based on the greater deployment of SMRs in the Global NZE scenarios. (Page 40).

SMR technology costs are not projected to improve over the period to 2050 due to the assumption that this is a mature technology and therefore, not amenable to further "learning".

Black coal with CCS[3]

Table B.8 of GenCost22, lists the assumed average capital cost of black coal generation with CCS in FY2021 as $9,077/kW and $8,816 in FY2030.

Coal technology costs are not projected to improve over the period to 2050 due to the assumption that this is a mature technology and therefore, not amenable to further "learning".

The CCS assumed cost reductions depend on the extent to which CCS technology is applied across a number of industries such as hydrogen production.

3.4 Application of Risk Premium to Black Coal

GenCost22 uses a 5.99% discount rate to calculate the LCOEs for all technologies with one exception. A variant is calculated for a new black coal plant where a 5% premium is added to the base discount rate because of the risks of higher financing costs due to the emission policies of Federal and State Governments.

The size of the premium is based on a 2017 Jacobs Report[4] which was prepared for the Finkel Review. The justification of the risk premium is to recognise "… that more emissions-intensive generators face greater investment risks than low emissions generators." (Page 22).

The Jacobs Report also applied a 1% risk premium to VRE technologies to recognise "… market or project risks they face due to their size, complexity of technology or because they have a high proportion of upfront capital costs." (Page 22).

4. Major issues with the GenCost22 data assumptions

4.1 Data assumptions for thermal and VRE technologies

Selection of capacity factors

The first major issue with the GenCost22 data is the selection of CFs in two areas.

First, the average GenCost22 CF for FY2021 and FY2030 for wind is 40% compared with the average for ISP22 of 35%. The average LS Solar PV CF is 26% for both GenCost22 and ISP22. The GenCost22 estimates are projections while the ISP22 wind CFs are estimates for 46 renewable energy zones for wind and 36 renewable energy zones for LS Solar PV, over an 11-year period.

As a reality check, the FY2022 CFs for the NEM were 29% for wind and 19% for LS Solar PV (which include the impact of MLFs). On the assumption that the better VRE sites have been taken first, it is reasonable to assume that CFs for new-build VRE technologies will be lower than the CFs currently being achieved.

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[3] Assumptions were also included for brown coal and gas with CCS. This Paper focusses on black coal with CCS.

[4] "Report to the Independent Review into the Future Security of the National Electricity Market: Emission mitigation policies and security of supply", Jacobs, Department of Energy and Environment, Canberra, 21 June 2017.

Secondly, GenCost22 assumed a 60% - 80% CF range for fossil fuel and SMR baseload technologies based on the expected operating regime of the plants. (Page 13). A basis for the assumption for black coal plants appear to be the CFs achieved recently by coal plants in the NEM.

However, the main reason for the recent CFs being lower than the plants' technical capabilities is the constrained dispatch of those plants due to the preference in dispatch given to VRE. This use of the market history rather than technical capability directly contradicts the GenCost22 New-build Methodology of analysing the cost and operation of new-build plant.

GenCost22 has a critical role to inform policy makers and the public of the cost trade-offs of replacing fossil-fueled technologies. To ensure that stakeholders are fully informed, the technically achievable capacity factors should be applied. If governments and regulators wish to constrain the operation of the new plants, the cost consequences will be available to compare with the benefits.

The ISP22 CFs for all thermal technologies are based on the assumed planned and forced (partial and full) outage rates for the new-build plants; that is, the CFs are based on the technical capability.

In contrast, the capacity factors of the VRE technologies are not constrained by technical capability but, rather, by the relevant wind and solar resources available at each time period.

Failure to take account of connection costs and marginal loss factors

The second major issue with the GenCost22 data is the failure to take account of the assumed connection costs[5] and MLFs used in ISP22.

Thermal technologies can be located near large load centres and associated fuel supply and transmission infrastructure which leads to relatively low connection costs and MLFs.

In contrast, VRE technologies are generally located in areas remote to the grid and load centres which leads to relatively high connection costs and MLFs.

The inclusion of connection costs and MLFs increases the unit costs and lowers the effective CFs of VRE generation technologies.

4.2 Data assumptions for LCD technologies

Nuclear SMRs

The GenCost22 estimates of SMR capital costs was based on 2015IEA, updated, supported by CNA2019 which is cited as the latest data source for SMRs. ISP22 does not analyse SMRs.

However, the IEA has updated its report "Projected Costs of Electricity Generation 2020" (**IEA2020**) and included updated cost estimates for new-build, nuclear generating technologies in various countries provided in IEA2015. The most recent IEA nuclear tracking report noted that achieving "…net zero globally will be harder without nuclear" and projects nuclear power to double between now and 2050.

[5] This is the cost to connect the different generation technologies to the transmission grid. It is distinct from the cost of expanding the main transmission network to integrate VRE technologies which GenCost22 addresses separately.

Both reports list the average cost[6] for predominantly light water reactors denominated in US dollars. The 2015 estimate has been escalated to 2022 terms by the US consumer price index and both estimates converted to Australian dollars at a 0.70 AUD/USD exchange rate. The results are set out in Table 4.1.

Table 4.1: IEA new-build nuclear cost projections

Source	$/kW
IEA2015	$7,670
IEA2020	$6,040

The results for large-scale units indicate that there has been a 21% reduction in costs in five years in Australian dollar terms, a period over which GenCost22 assumes virtually no cost reduction. In this context, the GenCost22 assumption that there is virtually no reduction in nuclear capital costs by 2050 appears unrealistic.

The GenCost22 assumption was developed by increasing the IEA2015 estimate to account for the higher cost of SMRs relative to large scale nuclear units and Australia's limited experience in nuclear generation.

In relation to the scale issue between large generation III reactors and SMRs, NuScale[7] "… believes that it will need to fabricate 12 to 14 modules to move down the learning curve from first-of-a-kind to "Nth-of-a-kind." (NuScale UK Prospectus, page 22). For a nuclear generator with the 77 MWe modules, the Nth-of-a-kind cost from NuScale is US$2,850/kW (Power Magazine, 11 November 2020) which converts to $4,100/kW Australian dollars at a 0.70 AUD/USD exchange rate. This unit cost is significantly lower than the IESA2020 estimate for large-scale plants.

The assertion regarding Australia's limited experience in nuclear generation can be challenged on numerous grounds:

- Australia has extensive experience in generating electricity from steam generation. The most likely SMR would be a light water based reactor. Much of the plant is the same as a coal-fired power station – turbine, feed pumps, electrical systems, cooling supplies, etc. Australia has extensive experience of this equipment. The steam is produced by a reactor instead of a coal-fired boiler.
- Australia has significant nuclear expertise based on the construction and operation of the nuclear reactor at Lucas Heights which is mainly used to produce medical isotopes and neutron beams for research application. The ANSTO OPAL reactor has more engineering complexity than current SMR designs. The construction of the OPAL research reactor is a good example of the capabilities for nuclear construction in Australia. From the first Federal announcement of the project to the reactor becoming operational was nine years. From the issue of the construction licence to the reactor operating was only four years. Many Australian companies were involved in this project.
- An Australian SMR would be a first of a kind locally but an nth of a kind internationally. Australia would not be a first mover.

[6] The costs are drawn from Table 3.1: Summary statistics for different generating technologies for overnight costs. Overnight cost includes pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction.

[7] NuScale Power Corporation, listed on the New York Stock Exchange.

- The complete reactor module would be imported from overseas and installed. Site construction time would be reduced and be more predictable.
- There will be a faster learning curve for SMRs because of the larger number of units that will be produced, compared to large reactors. For example, the NuScale plant has up to 12 modules in one plant.
- The existing expertise will be greatly increased with the development of eight nuclear submarines under the AUKUS alliance. The AUKUS agreement has already launched a major increase in nuclear skills in Australia. Student numbers at nuclear courses at both UNSW and the ANU have dramatically increased this year. There is an increased general awareness of the importance of nuclear technology.
- GenCost22 fails to make a similar adjustment to the cost assumptions of other generation technologies in which Australia currently has "limited experience". For example, Australia has limited experience in offshore wind generation.

The momentum to achieve NetZero2050 can reasonably be expected to result in cost reductions from the IEA2020 estimate. The IEA cost estimates have fallen by 21% in the five years to FY2020 or 4% per year. A conservative annual reduction of approximately 2% would yield a cost below $5,000/kW in FY2030.

Based on this analysis and the latest NuScale SMR Nth-of-a-kind cost of $4,100, a unit cost of $4,500/kW in FY2030 is used to test the impact on the estimated SMR LCOE in Section 5 and it has been included in Appendix 1 as an IEA2020 estimate. All other GenCost22 assumptions regarding SMRs are used except the fixed O&M cost, which is assumed to be approximately double the cost for black coal, the capacity factor, which is based on the technical capability of this baseload technology as well as a connection cost and a MLF comparable with the siting of a baseload plant capable of operating at high CFs.

Black coal with CCS

Table 4.2 sets out the GenCost22 FY2021 capital costs and the assumptions for FY2030 for black coal and black coal with CCS[8].

For reference, the estimated capital costs for Australian supercritical pulverised coal technology, with and without CCS from IEA2020[9], is also provided.

Table 4.2: GenCost22 and IEA Capital Cost Assumptions

Technology	**GenCost22**		**IEA2020**
	FY2021	**FY2030**	**FY2021**
	$/kW	$/kW	$/kW
Black Coal	$4,343	$4,208	$3,177
Black coal with CCS	$9,077	$8,631	$7,658

Two major issues arise.

[8] The average of the high and low assumptions published in Appendix Table B.8 (page 74).
[9] The IEA2020 average cost was escalated by the US CPI and converted to Australian dollars at a 0.70 AUD/USD exchange rate.

First, IEA2020 estimates of current costs are significantly lower than those cited by GenCost22 (and ISP22).

Secondly, the GenCost22 estimates imply very little cost reduction between 2021 and 2030 with a 3% reduction assumed over the 10 years for both black coal and black coal with CCS. As noted, GenCost22 classifies these technologies as mature and therefore, not amenable to significant further "learning".

This is in marked contrast for the following "Early" technologies which are projected to experience the following reductions in unit cost between 2021 and 2030[10]:

- Large-scale solar PV - 46%.
- Rooftop solar PV - 44%.
- Wind offshore - 36%.

Given that over 50% of the total cost is installation labour, the extent of these potential reductions appears to be very optimistic.

The most recent IEA CCUS[11] tracking report included the following:

"Strengthened climate goals and new investment incentives are delivering unprecedented momentum for CCUS, with plans for more than 100 new facilities announced in 2021. CCUS technologies will play an important role in meeting net zero targets …".

The cost reductions assumed for the VRE technologies reflect the assumed rapid deployment of these technologies driven by of the climate goals in the NetZero2050 scenario.

It is logical to expect this policy-driven momentum also to lower the cost of black coal with CCS. The momentum to achieve NetZero2050 can reasonably be expected to result in cost reductions from the IEA2020 estimate. An annual reduction rate of approximately 4% would yield a cost in the range of $5,500/kW in FY2030.

Based on this analysis, a unit cost of $5,500/kW in FY2030 is used to test the impact on black coal with CCS LCOE in Section 5. All other ISP22 assumptions for black coal with CCS are used. It has been included in Appendix 1 as an IEA2020 estimate.

4.3 Application of Risk Premium to Black Coal

The role of the discount rate is to allow comparable LCOEs to be calculated for a range of technologies using the New-build Methodology.

Thus, application of a risk premium only for calculating the black coal LCOE contradicts the GenCost22 New-build Methodology and should be removed from the analysis.

In any event, while there are undoubtedly financing risks for new coal plant, there are also financing risks for wind and solar projects, which was also identified in the Jacobs 2017 Study.

The installed VRE capacity is highly reliant on subsidies from the Federal and State Governments which have been associated with a significant increase in consumer electricity prices. There is a risk that

[10] Appendix Table B.2 Global NZE by 2050 scenario (page 68).
[11] The IEA refers to CCUS – carbon capture, use and storage.

future Governments might reduce or remove the subsidies, which will make new-build plant more difficult to finance.

Indeed, GenCost22 projects the building of approximately 53GW of wind and solar capacity at a 90% VRE Share at a cost of approximately $80 billion by FY2030. However, this financing risk is ignored by GenCost22.

If CSIRO wants to prepare a report on financing risks of new-build power plant, it will need to detail fully the impact of the current market issues such as an energy-only structure and take into account all the factors that may mitigate financing risks. The Australian Competition and Consumer Commission addressed this specifically in its Retail Electricity Pricing Inquiry—Final Report, June 2018 in which it recommended:

"Where private sector banks are unwilling to finance projects due to uncertainty about the future of an industrial or manufacturing business, the ACCC considers there is a role for the Australian Government in providing support for such projects in appropriate circumstances." (Page 99).

As the grid has deteriorated, the prospect of capacity payments has arisen. It is not a large step for the Government offering power purchase agreements to prevent major outages (i.e., "appropriate circumstances").

5. Impact of the major data issues on the LCOEs

The impact of the ISP22 assumptions on the estimated LCOEs is compared with the outcome of using the GenCost22 assumptions in Table 5.1. Again, the GenCost22 results are based on the GenCost22 average of the low and high case assumptions for capital cost, fuel cost and capacity factors.

Table 5.1: Impact of the major data issues on the LCOEs before integration

	LCOE – FY2021		LCOE – FY2030	
Technology	**GenCost22**	**ISP22 / IEA2020**	**GenCost22**	**ISP22 / IEA2020**
	$/MWh	**$/MWh**	**$/MWh**	**$/MWh**
Black coal	$93	$80	$97	$82
Gas CCGT	$107	$105	$119	$108
Gas turbine small	$195	$137	$210	$143
Gas turbine large	$177	$138	$191	$143
Black coal – CCS[1]	$172	$151	$176	$114
Nuclear (SMR)[1]	NA	NA	$218	$71
LS Solar PV	$53	$77	$38	$48
Wind onshore	$54	$74	$48	$69
1: Based on the assumptions set out in Section 4.2 and Appendix 1.				

When more current estimates of the capital cost of SMRs are used and adjustments are made for the capacity factors and the inclusion of connection costs and marginal loss factors, two major results are evident:

- The SMR and black coal estimated LCOEs reduce significantly compared with the results reported in GenCost22 notwithstanding the addition of the connection costs and MLFs. A major reason for this outcome is the lower SMR capital cost assumption and the higher ISP22 CFs based on the technical capability of the technologies.
- The wind and large-scale solar estimated PV LCOEs increase significantly compared with the results reported in GenCost22. A major reason for this outcome is the generally higher ISP22 capital cost assumptions and the lower CFs combined with the addition of the connection costs and MLFs.

As noted in GenCost22[12], these results are not directly comparable because the electricity from the thermal technologies is dispatchable while the electricity from the VRE technologies is intermittent.

The GenCost22 methodology deals with this incompatibility by adding integration costs to the VRE LCOEs in order to make electricity from the VRE technologies dispatchable (i.e., firm) and so, directly comparable with the costs from baseload technologies.

The results of an analysis of the adequacy of the GenCost2 estimates of integration costs is reviewed in the next Section.

6. GenCost22 analysis of VRE integration costs

6.1 Adequacy of integration costs

In addition to accounting for the direct costs, the LCOEs for VRE technologies include the impact of the costs incurred to "integrate" the VRE into the system to ensure all the LCOEs are directly comparable.

The integration costs are added to the "standalone" LCOE estimates to produce the integrated or firmed LCOE estimates.

The critical issue is whether the VRE integration costs adequately reflect the cost of the generation and storage capacity (commonly referred to as **Firming Capacity**) required to convert the intermittent electricity from VRE technologies to baseload, dispatchable electricity to ensure the system meets the reliability standard[13].

The major measure of the adequacy of the Firming Capacity required for a reliable system is the ratio of Firming Capacity to VRE Capacity (**Firming Ratio**).

GenCost22 attempts to describe the issue as follows:

"Variable renewables have a low capacity factor, which means the full capacity is only generating for a fraction of the year (e.g., 20% to 40%). As a result, to deliver the equivalent energy of a coal generator, the system needs to install around three times the variable renewable capacity. If system were to also build the equivalent capacity of storage, peaking and other flexible plant then the system now has six times the capacity needed when coal is deployed." (Page 60).

[12] "… a common concern is whether GenCost LCOE calculations have accounted for enough storage or other back-up to deliver a steady supply from variable renewables. Ensuring all costs are accounted for is important when comparing costs with other low emission technologies such as nuclear SMR which can provide steady supply." (Page 60).

[13] The NEM reliability standard is that there must be sufficient energy resources to match demand at least 99.998% of the time; i.e., supply fails to match demand for only 10 minutes per year on average. (AEMO 2022 Integrated System Plan, Table 2, page 23).

The first sentence is incorrect – VRE technologies only operate at "full capacity" for a very few hours per year. Rather, these technologies have low annual average CFs in the 20% - 40% range.

The second part of the paragraph, where each MW of VRE capacity is supported by a MW of Firming Capacity, describes a one-to-one ratio of Firming Capacity to VRE Capacity (**100% Firming Ratio**).

GenCost22 analyses the issue on two levels – a subjective review (**Subjective Analysis**) and an objective review based on the modelling (**Modelling Analysis**). Each Analysis is reviewed separately.

6.2 Gencost22 Subjective Analysis

GenCost22 concludes that a Firming Ratio much less than 100% will ensure a reliable system. The rationale is that, in a system with high VRE penetration, maximum demand "will be significantly lower" (page 60) than the installed VRE capacity.

Two factors determine the exact size of the Firming Ratio as follows:

First, there is existing peaking and flexible generation and storage capacity in the NEM which reduces the amount of new Firming Capacity required to meet demand. Thus, GenCost22 attributes no cost to the Firming Capacity supplied from existing resources. It is argued that this treatment applies to all generation technologies since all new generation is supported by existing generation capacity to meet demand.

Secondly, as the VRE Share increases, GenCost22 argues that the traditional summer and winter peaks may be easier to meet based on the following example:

"… during a summer peaking event, solar PV generation is high and consequently storages are relatively full and available to deliver into the evening peak period." (Page 61).

No example is provided why this is the case. Recent summer events in South Australia indicates that the statement is highly dubious. Further no example is provided why this is the case in winter peaking events.

Rather than the traditional peak periods, GenCost22 argues that, as the VRE Share increases, a "…more challenging period for variable renewable system might be on a lower demand day when cloud cover is high and wind speed is low. These days with low renewable generation and low charge to storages could see the greatest demands on storage, peaking and other flexible capacity." (Page 61)

6.3 GenCost22 Modelling Analysis

STABLE Model

GenCost22 applies the CSIRO STABLE model to estimate the optimised investment profile and operation to achieve reliability and security[14]. STABLE is described as an intermediate horizon model that co-optimises "… investment and operation for reliability and security (one to several hours' time steps for one to five years)" (Page 55). The model is a compromise which optimises over longer time periods rather than a dispatch model which optimises the dispatch of capacity to meet the reliability standard over each five-minute to half-hour period.

[14] GenCost 2020-21 Final report, CSIRO, June 2021.Section 5.1.

The model covers the NEM, the South-West Interconnected System in Western Australia and the remainder of WA.

STABLE is used to model the impact on system reliability of factors such as demand, weather conditions and the level of storage, peaking and other flexible capacity which were modelled across nine weather years for levels of imposed VRE penetration from 60% to 90%. The VRE capacity does not include rooftop solar PV (**RSPV**) which is absorbed in the demand profile.

In particular, STABLE was used to calculate the integration costs of renewables for FY2030 by "… imposing a required variable renewable energy (VRE) share and running the model to determine the optimal investment to support the VRE share." (Page 54).

It is assumed that all the scenarios modelled meet the required reliability and security standards.

Modelling weather variability

The major determinant of the generation from wind and solar PV technologies are wind speeds and irradiance levels (**VRE Resources**) in each time period.

A major issue is that the NEM regions are regularly subject to wind and solar droughts (**Weather Droughts**) due to the variability in VRE Resources.

GenCost22 accounts for Weather Droughts by using the maximum integration costs over nine weather years (2011 – 2019) estimated by the STABLE model. GenCost22 states that "… maximum cost represents a system that has been planned to be reliable across the worst outcomes from weather variation." (Page 55).

Modelling results

STABLE estimated Firming Ratios in FY2030 of 20% to 34% as the VRE Share increases from 60% to 90% in the NEM. Lower levels of VRE penetration are not considered because approximately "… 52% will be achieved in 2030 without any new policies." (Page ix).

The estimated integration costs of VRE in FY2030 are $16/MWh to $28/MWh as the VRE Share increases from 60% to 90%. The estimated integration costs are added to the standalone or unfirmed LCOEs of the VRE technologies to produce the estimated LCOEs of the integrated VRE technologies.

6.4 Restatement of the GenCost22 Modelling Results

The GenCost22 installed capacity and generation projections exclude RSPV and so, cannot be directly compared with the projections from ISP22 and other AEMO and CSIRO studies which explicitly treat RSPV as VRE.

For ease of comparison with the results of other studies, the major FY2030 ratios have been restated to include RSPV capacity and generation (see Appendix 2) and set out in Table 6.1.

Table 6.1: Restated GenCost22 FY2030 major ratios

	Excluding RSPV	Including RSPV	Excluding RSPV	Including RSPV
VRE Share	60%	67%	90%	92%
Firming Ratio	20%	11%	34%	23%

The inclusion of RSVP capacity and generation results increases the 60% VRE Share to 67% and the 90% VRE Share to 92%. The projected Firming Ratios are reduced as the installed Firming Capacity has to firm both the RSVP capacity as well as the other VRE capacity. Future references will be to the restated ratios.

It is noted that GenCost22 also allowed for transmission expansions in estimating integration costs.

7. Major issues with the GenCost22 analysis of VRE integration costs

7.1 Issues with the GenCost22 Subjective Analysis

The Subjective Analysis is materially deficient on two grounds.

Role and cost of Firming Capacity already installed

First, the critical issue is whether there is sufficient Firming Capacity to ensure the system reliability standard is met as the VRE Share rises. It is totally irrelevant whether this Capacity is already installed or needs to be constructed. This has no influence on the size of the required Firming Ratio.

Secondly, the failure of GenCost22 to attribute any cost to the Firming Capacity already installed is plainly incorrect in two respects:

1. The GenCost22 applies a New-build Methodology under which it is necessary to estimate the cost of newly built Firming Capacity. That is, the LCOE for VRE technology should account for building the VRE plants and the required Firming Capacity to integrate it into the system; that is, the LCOE for the new plant PLUS the LCOE of the new Firming Capacity.

   Thus, to attribute no cost to the installed Firming Capacity fundamentally breaches GenCost22's New-build Methodology.

2. Moreover, even if GenCost22 breaches its New-build Methodology with respect to Firming Capacity, it is illogical to assume that the support provided by the already installed Firming Capacity can be accessed at no cost. Clearly, the effective price of the installed Firming Capacity is set by the spot prices during the periods when the Capacity is dispatched under the dispatch protocols.

   The spot prices are set by the bidding process. In the current NEM, with a 23% VRE Share (including RSPV) and a 22% Firming Ratio, spot prices in peak periods significantly exceed the LCOE of Firming Capacity.

   Recent experience indicates that the cost of gas support often exceeds $300/MWh in peak periods.

Further, all new generation capacity does NOT require the support of Firming Capacity to deliver dispatchable, reliable electricity to the system. ONLY VRE requires this support as acknowledged in GenCost22.

The failure to factor in the cost of support from existing peaking and flexible generation and storage capacity in the NEM materially reduces the GenCost22 estimated LCOEs of firmed VRE generation.

Availability of VRE generation at the traditional peaks

The GenCost22 analysis assumes that the weather conditions at the traditional peaks will always allow sufficient VRE to be available, augmented by Firming Capacity, to meet the peak based on an example outcome for the summer peak, linked to solar PV. As noted above, this assumption is not supported by the recent experience in South Australia in particular.

An equivalent example to support the assertion that the winter peaks will be lower was not provided.

The assertion that VRE is in plentiful supply at the peaks is contradicted in the AEMO 2022 Statement Electricity of Opportunities, August 2022 (**ESOO22**) which analysed average winter, summer typical, and summer peak availability relative to nameplate capacity by type of generation. The ESOO22 analysis highlighted "… the reduced availability reported in summer peak compared to winter and summer typical. This is especially noticeable for wind generators, due to some reporting 0 MW availability during summer peak, reflecting high-temperature cut-offs for this generation category." (Page 44).

Thus, rather than simply assuming that the peak demand can always be met, GenCost22 should have analysed the reliability of the system on peak demand days that are cloudy and not windy.

Finally, having assumed away the major problem of meeting demand, GenCost22 then, remarkably, focuses on system reliability in periods of low VRE generation rather than in periods of peak demand.

7.2 Issues with the GenCost22 Modelling Results

The Modelling Results are materially deficient on two grounds.

Results do not reflect current market reality

First, GenCost22 projects a reliable NEM system in FY2030 with Firming Ratios of 11% - 23% and an average VRE Share of 67% - 92% (including RSPV).

In comparison, the NEM has been very unstable in recent months leading to a suspension of the market and a rationing of supply, especially at peak periods. The NEM currently has a Firming Ratio of 22% and an average VRE Share of 23% (including RSPV).

Thus, the GenCost22 projections appear highly optimistic based on the current NEM structure.

Secondly, ESOO22 identified reliability gaps in South Australia, Victoria and NSW in FY2024, FY2025 and FY2026 respectively (page 55), progressively worsening to a combined reliability gap in NSW, Victoria and Queensland of 3,810MW in FY2030. (Page 58).

ISP22 explicitly focused on system reliability by the inclusion of a step to "Test and confirm system reliability and operability." (ISP22, page 35). Thus, the ISP22 results are a relevant benchmark against which to assess the reliability of the GenCost22 projections for the NEM in FY2030.

The projected FY2030 levels of Firming, VRE and total installed capacity projected in the ESOO22 and the ISP22 are set out in Table 7.1 alongside the projections from GenCost22, including RSPV (see Appendix 2).

Table 7.1: FY2030 NEM Projections: GenCost22 (including RSPV), ESOO22 and ISP22

	Units	GenCost22		ESOO22	ISP22
Firming Capacity	GW	9	23	10	23
VRE Generation Capacity	GW	81	104	53	79

Firming Ratio	%	11%	23%	19%	30%
Total Generation	TWh	255	255	255	255
VRE Generation	TWh	171	234	115	171
VRE Generation Share	%	67%	92%	45%	67%

The results indicates that in FY2030:

- ESOO22 projects a massive capacity shortfall with a 45% VRE Share supported by a 19% Firming Ratio.
- ISP22 projects a reliable system with a 67% VRE Share supported by a 30% Firming Ratio.
- GenCost22 projects a reliable system with a 67% - 92% VRE Share supported by a 12% - 23% Firming Ratio.

Thus, compared with current and projected NEM conditions, the GenCost22 Firming Ratios appear very low relative to the relevant VRE Share and strongly indicate that GenCost22 materially understates the amount and cost of the capacity required to firm VRE generation to ensure a reliable system.

Results not supported by previous CSIRO analysis

The GenCost22 modelling results of a 20% - 34% Firming Ratio are in stark contrast to earlier CSIRO modelling referenced in CSIRO's "Low Emissions Technology Roadmap", June 2017 (**CSIRO 2017 Roadmap**).

The CSIRO 2017 Roadmap reports the results of a detailed analysis and modelling of the levels of battery capacity (i.e., Firming Capacity) required to be installed to ensure a reliable supply as the VRE Share in the system increases. In particular, the CSIRO 2017 Roadmap derived estimates of the Firming Capacity required to support VRE through Weather Droughts to ensure that modelled systems were "… robust under highly unlikely weather conditions." (Page 116).

Such an approach is necessary because of the significant evidence that the NEM is subject to extensive Weather Droughts.

The analysis of AEMO data reported by the Independent Engineers and Scientists in their "Response to Draft AEMO Integrated System Plan, 10 February 2022" shows multiple events of wind CFs below 10%, lasting at least 18 hours. In other periods, CFs dropped to virtually zero for days. (see Appendix 4) Solar CFs are highly variable based on time of day and season as well as prevailing weather conditions.

Further, the recent Australian Energy Regulator's Wholesale Markets Quarterly for Q2, 2022, released in September 2022, highlighted the impact of Weather Droughts as follows:

- "… on average, there was less solar electricity generated (in Queensland) per MW of capacity in 2022 than 2021. This pattern is consistent with impacts in other regions. This not only impacts large scale solar generation but also rooftop solar generation (effectively increasing demand). This resulted in other generators needing to operate at higher levels than anticipated to meet demand." (Page 16).
- "While wind output levels vary markedly from week to week, average output from wind in SA was down for two-thirds of the weeks of the quarter. Wind levels were particularly low in the

week leading up to market suspension. In weeks where wind is low, other generators need to operate at higher levels to meet demand." (Page 17).

Appendix 3 reproduces Figure 11 of the CSIRO 2017 Roadmap which depicts the relationship between the VRE Share and the Firming Ratio in the NEM regions which increases exponentially as the VRE Share increases. Half-hourly modelling was used to derive these estimates in order to capture the rapid swings in VRE generation due to weather variability.

Specifically, the CSIRO 2017 Roadmap results indicate that a Firming Ratio of approximately 30% is required for 67% VRE Share and 75% for 90% VRE Share.

Issues with the STABLE Model

The effect of Weather Droughts is to prevent VRE technologies from generating for extended time periods within a year.

The CSIRO 2017 Roadmap and ISP22 used half-hourly modelling to optimise dispatch which picks up Weather Droughts over short-time periods.

In contrast, the STABLE Model can only measure the impact of Weather Droughts over much longer time periods and appears not well suited to estimating the amount of Firming Capacity required to meet the system reliability standard within short-time periods. Thus, the use of average CFs over broad time periods cannot pick-up seasonality (especially for solar) and Weather Droughts where CFs are low for weeks at a time.

7.3 Cost of Integrated VRE Generation based on the CSIRO 2017 Roadmap Firming Ratios

As noted, the CSIRO 2017 Roadmap results indicate that a Firming Ratio of approximately 30% is required for 67% VRE generation and 75% for 90% VRE generation. These ratios were used to recalculate the cost of firmed VRE generation based on Firming Capacity comprised of battery storage (8 hours). The results are set out in Table 7.2 for the FY2021 and FY2030 ISP22 data assumptions set out in Appendix 1.

Table 7.2: Cost of Firmed VRE Generation based on the CSIRO 2017 Roadmap Firming Ratios

Technology	**LCOE**	**LCOE**
Cost Base	**FY2021**	**FY2030**
Black coal	$80	$82
Gas CCGT	$105	$108
Gas turbine small	$137	$143
Gas turbine large	$138	$143
Black coal - CCS	$151	$114
Nuclear (SMR)	NA	$71
LS Solar PV - 67% VRE share	$129	$73
LS Solar PV - 92% VRE share	$207	$112
Wind onshore - 67% VRE share	$112	$88
Wind onshore - 92% VRE share	$169	$116

The major conclusions from the amended results are as follows:

- The estimated wind and large-scale solar PV LCOEs increase significantly compared with the results reported in GenCost22 (Table 1.1) and Table 5.1 after allowing for the Firming Ratios determined in CSIRO 2017 Roadmap using battery storage (8 hours).
- Based on FY2021 cost assumptions and a 67% VRE Share, the estimated LCOEs for both large-scale solar PV and wind significantly exceed those for black coal and gas CCGT.

  Based on a 92% VRE Share, the estimated LCOEs for the VRE technologies are higher than those for all other technologies.
- Based on FY2030 cost assumptions and a 67% VRE Share, the estimated LCOE for large-scale solar PV is higher than that for SMRs with the wind LCOE higher than that for black coal.

  At a 92% VRE, the estimated LCOEs for the VRE technologies are higher than those for all other technologies except small and large gas turbines.
- As noted in Section 3.2, the major reason for the lower LCOE estimates for the firmed VRE technologies in FY2030 is the assumed rapid reduction in the unit costs of large-scale solar PV and batteries. If these assumptions prove overly optimistic, the LCOEs will increase significantly.
- The amended results do not include the cost of transmission expansions which could potentially increase the integration costs.

It is noted that only battery storage (8 hours) was used as Firming Capacity, to reflect the results of the CSIRO 2017 Roadmap faithfully. In practice, it might be more efficient to use a mixture of battery storage and gas generation (or some other form of flexible dispatchable generation) as the Firming Capacity, as opposed only to battery storage. As CSIRO 2017 Roadmap notes, the dispatchable capacity is crucial "… to run the system when there are extended periods of low wind and sun, without the need for a much more costly deployment of batteries." (Page 47).

This may reduce the required Firming Ratios but may increase the LCOEs because of the high cost of gas that is projected.

8. Conclusion

This Paper presents the results of an analysis of the GenCost22 estimates of the LCOEs from building a range of new electricity generation and storage technologies.

The GenCost22 findings, as CSIRO states, are required by governments and regulators to assess alternative policies and regulations (Page10). In this context, GenCost22 has a critical role to inform policy makers and the public of the cost trade-offs of replacing fossil-fueled technologies.

GenCost22 provides the results of a subjective and objective modelling analysis of the firming requirements to ensure a reliable system as the VRE Share increases from 67% to 92% (after adjusting for the inclusion of RSPV). The modelling analysis concludes that a 20% - 34% Firming Ratio is required to integrate VRE technologies and ensure a reliable system at an estimated cost of \$16/MWh - \$28/MWh.

Based on GenCost22, CSIRO's major conclusion is "… that wind and solar are the cheapest source of electricity generation and storage in Australia, even when considering additional integration costs arising due to the variable output of renewables, such as energy storage and transmission."[15] …". Based on this conclusion, policy makers could easily assume that the transition to low-carbon energy will lower the cost to consumers of a reliable electricity supply.

There are, however, a number of major unresolved issues over the estimated costs of integrating VRE technologies with the other non-renewable technologies in Australia's future power system.

This Paper has identified major deficiencies and omissions with the GenCost22 data assumptions including:

- Assumed capacity factors for VRE technologies that significantly exceed capacity factors currently observed in the market.
- Assumed capacity factors for baseload technologies that are significantly lower than the technical capabilities of new-build plant.
- A failure to take account of connection costs and marginal loss factors which are relatively high for VRE technologies.
- Outdated and significantly overstated capital cost estimates for nuclear SMRs.

The Paper has also identified the significant underestimation of the cost of integrating, or firming, VRE technologies to achieve a reliable system including:

- Failing to attribute any cost to the currently installed firming capacity which is inconsistent with the New-build Methodology and the current pressure on system reliability and the high market prices.
- Projecting a reliable system in the same time period that AEMO is predicting major capacity shortfalls, with similar technology mixes, lower VRE penetration and more firming capacity.
- The inconsistency with an earlier, detailed CSIRO study which sought to ensure that the system was robust during Weather Droughts when VRE resources are absent or low for long periods.

When adjustments are made for these factors, a 30% - 75% Firming Ratio is required to integrate VRE technologies and ensure a reliable system as the VRE Share increases from 67% to 92% at an estimated average cost of $44/MWh - $111/MWh at current costs and $22/MWh - $54/MWh at the FY2030 assumptions. The lower firming cost estimates using the FY2030 assumptions requires the achievement of a rapid reduction in the unit cost of VRE technologies and Firming Capacity.

Applying these adjusted firming costs, the recalculated LCOEs, set out in Table 8.1, contradict the GenCost22 conclusion that integrated wind and solar are the "cheapest" new generation technologies. They also indicate that the cost of Australia moving to a predominantly renewables power system has been materially underestimated.

Table 8.1: Results of Comparative Analysis of LCOEs in FY2030

Source	**GenCost22[1]**	**Amended[2]**	**Amended[3]**
Cost Base	**FY2030 Assumptions**	**FY2021 Current**	**FY2030 Assumptions**
Technology			
Black coal	$97	$80	$82
Gas CCGT	$119	$105	$108

[15] CSIRO Media Release - 11 July 2022

GT small	$210	$137	$143
GT large	$191	$138	$143
Black coal - CCS	$176	$151	$114
Nuclear (SMR)	$218	NA	$71
Unfirmed - standalone			
LS Solar PV	$38	$77	$48
Wind onshore	$48	$74	$69
Firmed – integrated 67%[4] VRE Share			
LS Solar PV	$54	$129	$73
Wind onshore	$64	$112	$88
Firmed – integrated 92%[4] VRE Share			
LS Solar PV	$66	$207	$112
Wind onshore	$76	$169	$116

1. Applying the GenCost22 FY2030 assumptions to the GenCost22 firming requirements in FY2030.
2. Applying the current FY2021 costs to the amended firming requirements in FY2030.
3. Applying the amended FY2030 assumptions to the amended firming requirements in FY2030.
4. Adjusted from 60% and 90% respectively by including rooftop solar PV as VRE.

Based on current costs, the integrated VRE technologies are significantly more expensive than baseload thermal technologies for all the VRE Shares analysed. Using the FY2030 cost assumptions, the VRE technologies are not the cheapest new generation technologies being more expensive than SMRs in all cases and more expensive than black coal except for LS Solar PV at the lowest VRE Share. Again, the improvement in the competitive position of the VRE technologies requires the achievement of the assumed rapid reduction in the unit cost of VRE technologies and Firming Capacity.

These amendments to the GenCost22 findings do not mean that the transition to a low carbon energy sector is not important and worthwhile.

However, the analysis of the GenCost22 findings in this Paper has highlighted the importance of Australian policy makers and stakeholders being better and more reliably informed of the likely future costs of making the transition to a low carbon generation sector. For that purpose, an urgent, in-depth review of the GenCost22 findings and their implications is recommended.

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Appendices

Appendix 1: Summary of GenCost22 and ISP data

FY2021 - Average	Source	Economic Life	Construction	Capital Cost	Connection Cost	FOM	VOM	Fuel Cost	Heat Rate	CF	MLF
Technology		Years	Years	$/kW	$/kW	$/kW/yr	$/MWhso	$/MWhso	GJ/MWhso	%	%
Black coal	G22[1]	30	2.0	$4,343	$0.00	$53.20	$4.21	$2.55	9.0	70%	30
	I22[2]	30	2.0	$4,615	$91.67	$55.15	$4.37	$2.33	8.8	93%	30
Gas CCGT	G22[3]	25	1.5	$1,559	$0.00	$10.90	$3.70	$11.36	7.1	70%	25
	I22	25	1.5	$1,807	$91.63	$11.30	$3.84	$10.91	7.2	93%	25
Gas turbine small	G22	25	1.3	$1,290	$0.00	$12.60	$12.00	$11.36	10.0	20%	25
	I22	25	1.3	$1,519	$94.93	$13.06	$4.25	$11.33	10.2	97%	25
Gas turbine small	G22	25	1.1	$873	$0.00	$10.20	$7.30	$11.36	10.8	20%	25
	I22	25	1.1	$905	$94.93	$10.57	$2.49	$11.33	10.9	97%	25
Black coal with CCS	G22	30	2.0	$9,077	$0.00	$77.80	$7.95	$2.55	12.0	70%	30
	IEA	30	2.0	$9,656	$91.67	$80.66	$8.24	$2.33	14.3	93%	30
Nuclear SMR	G22	NA	NA	NA	$0.00	NA	NA	NA	NA	NA	NA
	IEA	NA	NA	NA	$0.00	NA	NA	NA	NA	NA	NA
LS Solar PV	G22	30	0.5	$1,441	$0.00	$17.00	$0.00	$0.00	0.0	27%	30
	I22	25	0.5	$1,625	$188.82	$18.54	$0.00	$0.00	0.0	26%	25
Wind onshore	G22	25	1.0	$1,960	$0.00	$25.00	$0.00	$0.00	0.0	40%	25
	I22	25	1.0	$2,099	$188.82	$27.27	$0.00	$0.00	0.0	35%	25
Battery Storage (8 hours)	I22	20	0.4	$3,078	$87.67	$28.02	$0.00	$0.00	0.0	0%	20

1. G22 – Gencost22 - Appendix Table B.8.
2. I22 – ISP22 - Final ISP - Inputs assumptions and scenarios workbook - Step Change Scenario.
3. IEA – IEA2020 – Section 4.2.
4. Round trip loss.

FY2030 - Average	Source	Economic Life	Construction Time	Capital Cost	Connection Cost	FOM	VOM	Fuel Cost	Heat Rate	Capacity Factor	MLF
Technology		**Years**		**$/kW**	**$/kW**	**$/kW/yr**	**$/MWhso**	**$/MWhso**	**GJ/MWhso**	**%**	**%**
Black coal	G22	30	2.0	$4,216	$0	$53.20	$4.21	$3.15	9.0	70%	0%
	I22	30	2.0	$4,532	$91.67	$55.15	$4.37	$2.70	8.8	93%	98%
Gas CCGT	G22	25	1.5	$1,513	$0	$10.90	$3.70	$13.10	7.1	70%	0%
	I22	25	1.5	$1,775	$91.63	$11.30	$3.84	$11.45	7.2	93%	98%
Gas turbine small	G22	25	1.3	$1,252	$0	$12.60	$12.00	$13.10	10.0	20%	0%
	I22	25	1.3	$1,491	$94.93	$13.06	$4.25	$11.87	10.2	97%	99%
Gas turbine large	G22	25	1.1	$741	$0	$10.20	$7.30	$13.10	10.9	20%	0%
	I22	25	1.1	$889	$94.93	$10.57	$2.49	$11.87	10.9	97%	99%
Black coal with CCS	G22	30	2.0	$8,816	$0	$77.80	$7.95	$3.15	12.0	70%	0%
	IEA	30	2.0	$5,500	$91.67	$80.66	$8.24	$2.70	14.3	93%	98%
Nuclear SMR	G22	30	3.0	$12,338	$0	$200.00	$5.33	$0.60	10.3	70%	0%
	IEA	30	2.0	$4,500	$91.67	$100.00	$5.33	$0.60	10.3	93%	98%
LS Solar PV	G22	30	0.5	$899	$0	$17.00	$0.00	$0.00	0.0	26%	0%
	I22	25	0.5	$848	$188.82	$18.54	$0.00	$0.00	0.0	26%	94%
Wind onshore	G22	25	1.0	$1,765	$0	$25.00	$0.00	$0.00	0.0	41%	0%
	I22	25	1.0	$1,937	$188.82	$27.27	$0.00	$0.00	0.0	35%	95%
Battery Storage (8 hours)	I22	20	0.4	$1,302	$87.67	$28.02	$0.00	$0.00	0.0	0%	83%

Appendix 2: Restatement of the GenCost22 Modelling Results

Since the STABLE model is consistent with ISP22 data sets (page 55), the original GenCost22 projections for FY2030 have been adjusted for the ISP22 total generation and RSPV projections as follows:

- RSPV – 35GW.
- RSPV – 45TWh.
- Total Generation including RSVP – 255TWh.
- VRE Ratios (excluding RSPV) are 60% and 90%.

The calculations are set out below.

Excluding RSPV			
VRE Share	%	60%	90%
Firming Ratio (Page 61)	%	20%	34%
VRE Generation Capacity (Figure 5.7, page 62)	GW	46[1]	69
Implied Firming Capacity based on Firming Ratio	GW	9	23
VRE Generation based on VRE Share	TWh	126	189
VRE Capacity Factor	%	31%[1]	31%
1 Estimate based on the 90% VRE Share capacity factor.			
Including RSPV			
Implied VRE Share	%	67%	92%
Implied Firming Ratio	%	11%	23%
VRE Generation Capacity from above plus ISP22 RSPV Capacity	GW	81	104
Implied Firming Capacity from above	GW	9	23
VRE Generation from above plus ISP22 RSPV Generation	TWh	171	234
ISPP22 Projections			
Total Generation including RSPV	TWh	255	
Rooftop PV Capacity	GW	35	
Rooftop PV Generation	TWh	45	
Total Generation excluding RSPV	TWh	210	

Appendix 3: Firming Ratios estimated from CSIRO Modelling

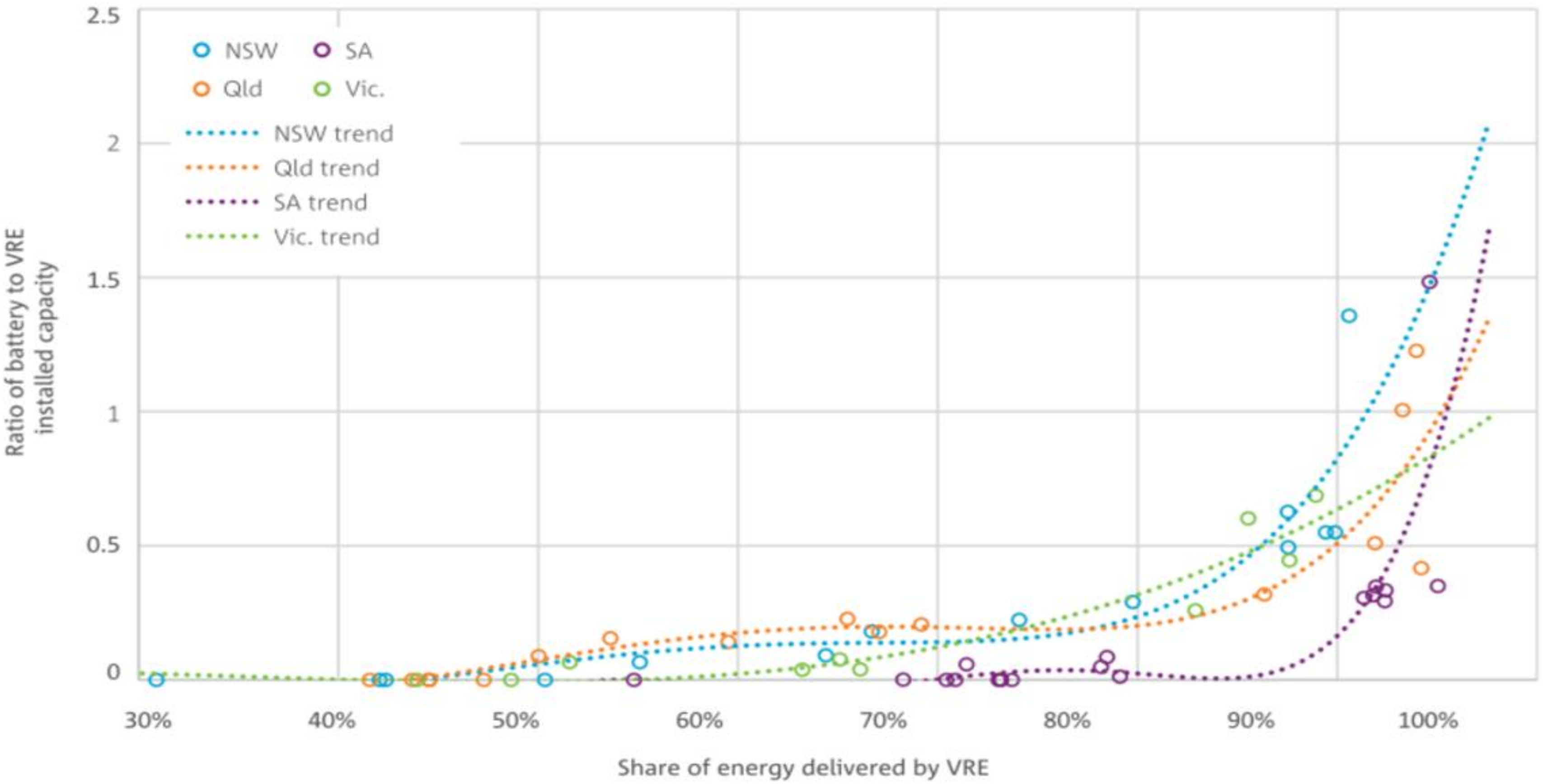

Figure 11. Ratio of battery and VRE generation capacity (GW) required to achieve energy balancing for modelled shares of energy (GWh) delivered by VRE

Appendix 4: Response to Draft AEMO Integrated System Plan, 10 February 2022, Independent Engineers and Scientists, Table 1, page 11.

Periods of Wind Capacity Factor Below 10%			
Year	**Number**	**Minimum Period hrs**	**Maximum Period hrs**
2011	6	18	74
2012	19	20	67
2013	9	19	54
2014	14	20	46
2015	16	18	39
2016	6	18	61
2017	18	18	72
2018	6	18	57
2019	4	18	40
2020	4	18	33
Table 1 SE Australia Wind Capacity Factor Data			

About the Author

David Carland *has over 40 years of investment banking and commercial experience in both the private sector and government. He is the Executive Director of Australian Resources Development Pty Ltd, a company focussed on the provision of specialised advice and assistance on energy and resource projects.*

David is currently the Non-Executive Chairman of an ASX-listed company and has been Chairman and a Director of several other listed companies.

David was the co-founder and part-owner of BurnVoir Corporate Finance Limited, an independent specialist banking firm focussed on the energy, resource and infrastructure sectors. Prior to this, David was Executive Vice President and head of energy and power at Bankers Trust, and before that he was Deputy Managing Director and head of corporate finance at UBS Australia. David has also held senior executive roles with the CRA Group (now Rio Tinto), including management of the commercial arrangements for the purchase of the Gladstone Power Station.