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WHAT ARE THE FULL SYSTEM COSTS OF RENEWABLE ENERGY?

Stephen Wilson

Cape Otway Associates

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Key Points

- Australia faces the replacement of more than two thirds of its power generation capacity over the next three decades.
- It is believed by many renewable energy advocates that variable renewable energy (VRE) options could replace coal- and gas-fired capacity without compromising the reliability of the power system. However, there is little understanding of the likely costs of doing so.
- Most models of future full system costs are based on unrealistic assumptions. This paper outlines an approach to future costs that is based on a more realistic understanding of the technologies involved.
- To be deployed at system-wide scale in the future generation mix, wind and solar need backup or storage. This paper provides an indication of the cost level of technology pairs that is more realistically comparable with traditional dispatchable generation.
- The results imply that at current costs VRE options are unaffordable at scale. The costs of the VRE options considered by this paper vary from an estimated $125/MWh in the case of the wind/gas option to $1,200/MWh in the case of the rooftop solar/battery option at household level.
- The Levelised Cost of Energy (LCoE) approach does not provide an adequate foundation either for formulation of sound energy policy or for system planning.

Introduction and context

The majority of the thermal generation fleet in Victoria, New South Wales and Queensland is due for retirement in the 2020s and 2030s. Available gross installed capacity on the National Electricity Market (NEM) system is currently about 48 GW.

A total of 5466 MW of coal- and gas-fired thermal capacity including plants in all five states of the NEM has recently retired, been withdrawn from service or mothballed. Another 4,375 MW of coal- and gas-fired capacity is due for retirement by the end of 2029. A further 21,525 MW of coal and gas-fired capacity is due for retirement by 2039. By 2045, all but the youngest plants—the four supercritical coal-fired plants in Queensland, which total 2,854 MW —will have passed their retirement dates. It is notable that a number of the recent plant retirements have occurred before their technical retirement dates.[1] Most recently installed gas peakers will also be over 30 years old by 2045, but retirement will be influenced by their accumulated hours.

By 2050, *all of the existing generation on the NEM* — except for the 7,822 MW of hydropower plants plus 640 MW of hydro pumped storage, which have notional technical lives of 150 years — will have either been replaced, or undergone capital-intensive refurbishment and life-extension. That includes recently constructed wind farms and solar capacity, which have notional lives of only 25 and 30 years, respectively.

Australia faces the replacement of about 34 GW of thermal capacity over the next three decades. With a lead time of up to seven years for the planning, development, financing, construction and commissioning of large plants, the current debate is about capacity that will come online between 2025 and 2050, which will determine the nature of Eastern Australia's post-2050 generation mix.

Some observers in Australia believe that the nation's retiring coal- and gas-fired capacity could be replaced with a combination of intermittent wind and solar renewable energy, complemented by flexible gas-fired backup plant, pumped storage hydro power and batteries. This is typically anchored to Article 2(a) of the Paris agreement on:

> *Holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change*

When combined with the IPCC's central view on the sensitivity of the climate to CO_2 and published models to convert emission paths to atmospheric CO_2 concentrations, this has led many to the populist view that a net zero emissions constraint by 2050 is 'inevitable' and that coal and gas-fired generation has only a limited future.

This begs a vital question:

What would it actually cost to meet electricity demand with such a generation mix, without compromising the reliability and stability of the system?

This paper makes a contribution to the discussion by providing an initial indicative answer to that question.

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[1] Swanbank B and Collinsville in Queensland were taken offline five and 16 years early, respectively. Munmorah and Wallerawang C were taken off seven and nine years early, respectively. Redbank was mothballed 37 years before its retirement. In Victoria, Energy Brix, Alcoa's Anglesea and Hazelwood are 1960s plants, retired before their permitted life. In South Australia, Playford B was retired at 52 years, versus a technical life of 60 and Northern was retired 19 years before its 50 year technical life. In Tasmania, Bell Bay was retired after 38 years.

Beyond the economic cost

Many other important questions follow from the cost question, including:

- Would the electricity price be internationally competitive?
- How many industries would close or be driven offshore?
- Would the electricity prices implied by the costs be politically acceptable?
- What are the implications for the economy, employment and the Federal budget?
- By how much would global CO_2 emissions be reduced, versus just shifted offshore?
- What are the implications for household affordability?
- What are the implications for banks' mortgage and commercial loan portfolios?

Those and other important questions are beyond the scope of this paper, but all flow from the underlying economic costs as the key issue at root.

Approach

It is common to use the Levelised Cost of Energy (LCoE) approach to compare the economics of generation from wind turbines and solar panels with generation from coal- or gas-fired plants. This approach is very convenient but it overlooks the full system costs that are incurred in matching generation with demand and maintaining system stability and reliability. As more intermittent generation is added to the system, the dispatchable generation is called on to play a greater and greater role in matching not only the real time variability in customers' demand but also the real time variability in intermittent generation.

One way of overcoming the shortcomings of LCoE is to compare the LCoE of variable renewable energy (VRE) with only those costs that it avoids elsewhere in the system, namely the fuel and variable operating and maintenance costs. VRE does not avoid the need for capacity in other generation plants, so the capacity component of other plants' LCoE should not be compared with VRE LCoE. Such an approach may be economically valid but does not answer the question on the full system cost of VRE.

The approach in this paper is to estimate the cost of VRE when paired with another technology, such that the combination of the two can deliver output comparable to conventional dispatchable generation. The technology pairs considered are:

1. Small scale rooftop solar PV paired with batteries
2. Medium to utility scale PV paired with reciprocating engines or turbines (OCGT)
3. Large arrays of wind turbines paired with open cycle gas turbines
4. Large arrays of wind turbines paired with pumped hydro energy storage (PHES).

Readers will note that the first and fourth pairs in the list are zero-emission combinations, where the economics are dominated by capital costs, with very low operating and maintenance costs and no fuel costs. The second and third pairs in the list entail significant remaining emissions associated with the backup fuel, and hence are sensitive to fuel costs (and remain exposed to future carbon prices and policies).

This approach is substantially more realistic than the traditional and simplistic LCoE comparisons mentioned above. Although it is stylised and not as detailed as running a full system model, it has the virtue of transparency; honours Ockhams' law of parsimony by requiring far fewer assumptions than a full system model; focuses on the VRE resources of interest; prevents very real system costs being hidden by shifting them 'outside the box' or losing them by dilution, as happens when they represent a small share of a large system.[2]

The shape of the load being served has a material influence on the cost of generation, because capacity is required to meet the peak demand, however brief. Therefore, the load factor, and the alignment or misalignment between instantaneous VRE output and demand on a 24-hour by 365-day basis needs to be considered.

Results and implications

The annual load factor (ALF) is the ratio of average demand over all hours in the year to peak demand and is by definition between zero and one. The cost of the technology pairs is matched with load factors to estimate the full system cost, as shown in the table.

Technology pair	Representative load served	ALF
1. Small-scale rooftop solar PV with batteries	(a) A typical residential load with a very low annual capacity factor and *no grid connection*	0.15
	(b) Diversity across multiple residences connected to a local distribution network on the grid	0.20
2. Medium- to utility-scale PV paired with reciprocating engines or turbines	(a) Diversity across multiple residences connected to a local distribution network on the grid	0.20
	(b) A commercial load profile with a higher capacity factor than residential but lower than industrial	0.50
3. Large arrays of wind turbines paired with open cycle gas turbines (OCGT)	(a) System average load profile representing residential, commercial and industrial loads	0.50
	(b) An industrial sector load profile with a diversity of large, medium and smaller factories.	0.75
4. Large arrays of wind turbines paired with pumped hydro energy storage	(a) A single large industrial site dominated by loads with very high annual load factor	0.75
	(b) Pure base-load, either at the system level, or representing an aluminium smelter	1.00

Note: the selected ALF values are realistic round numbers for illustrative purposes. For example, the system ALF for SA for 2015-16 (not including behind-the-meter solar PV) was 0.49, based on AEMO data.

This approach allows like-with-like comparisons between technology pairs serving the same load factor (pairs 1 and 2, pairs 2 and 3 and pairs 3 and 4). At the same time, it does not attempt to apply

[2] The method itself is detailed in a paper on *The Levelised Cost of Dispatchable Energy (LCoDE)* (forthcoming, 2017) by Martin Oettinger and Stephen Wilson.

generation technologies to loads that are technically inappropriate. To take a stark example for illustration, *it will never make sense to attempt to supply an aluminium smelter with electricity from solar PV and batteries*, for a large number of technical and economic reasons, and so this paper does not do so. The results are shown below.

Technology pair	Summary of key inputs	ALF	LCoDE *AU$/MWh*
1. Small-scale rooftop solar PV with batteries	(a) 5 kW PV array plus 3 x Tesla PowerWall 2.0 batteries, inverter, installation: at least $50,000	0.15	up to $1200
	(b) 100 kW PV community array @$2000 /kW plus 1.7 MWh of battery storage @$200/kWh	0.20	up to $600
2. Medium- to utility-scale PV paired with reciprocating engines or OCGT	(a) 1000 kW PV commercial array @$2000 /kW plus 5000 kW small diesel or gas-fired backup *	0.20	$160~250
	(b) 1000 kW PV commercial array @$2000 /kW plus 2000 kW small diesel or gas-fired backup *	0.50	$135~220
3. Large arrays of wind turbines paired with gas-fired OCGT backup	(a) 200 MW wind farm @$2500/kW plus 400 MW open cycle gas turbine backup	0.50	$135~150
	(b) 200 MW wind farm @$2500/kW plus 267 MW open cycle gas turbine backup	0.75	$125~145
4. Large arrays of wind turbines paired with pumped hydro energy storage	(a) 200 MW wind farm @$2500/kW plus 267 MW pumped hydro storage	0.75	$300-350
	(b) 200 MW wind farm @$2500/kW plus 60 MW pumped hydro storage	1.00	$175-250

Source: Author's calculations using cost data from Bongers, et al (2016) *Australian Power Generation Technology*, CO2CRC, Melbourne, www.co2crc.com.au; Blakers et al (2017) *100% Renewable Energy in Australia* and AEMO wind data for South Australia, 2015-16.

* The lower costs are for gas at $10 /GJ in an open cycle gas turbine (OCGT), the higher costs for diesel fuel at $18.50 /GJ. Gas at $10/GJ in a reciprocating engine is slightly more expensive but more flexible than in an OCGT

The calculations for the above results are available from the author upon request. VRE costs continue to decline, but the technology is rapidly maturing. As with any technology, constant percentage reductions in cost translate into ever smaller absolute reductions over time. Meanwhile, the gap between VRE costs and current generation system costs remains very high. The fuel plus operating costs of existing Australian coal plants is $10 to $40 /MWh. The all-in cost from a new state-of-the-art coal plant is estimated at $75 to 85 /MWh. The fuel-only cost for an OCGT gas peaking plant using $10 /GJ gas is about $100 /MWh.

Discussion

The analysis presented above is based on the capital investment required to match generation to a variety of representative load profiles ranging from low load factor residential load, through commercial and system average loads to high load factor industrial loads.

As the results show, using battery storage to firm up solar PV is extremely expensive (1a). The costs are reduced with higher load factor through diversity (1b), but at greater than $500/MWh, the costs are still very high, network costs, not included here, need to be added and it must be noted that the lowest long-run estimates of reduced battery costs ($200/kWh of storage capacity) have been assumed. On any realistic assessment, battery storage for anything other than small experimental applications represents a gross misallocation of capital, even after the most optimistic long-run cost reductions have been factored in.

Using small reciprocating engines as backup for solar reduces the costs, to between $150 and $250 /MWh, depending whether the fuel is natural gas ($10/GJ assumed) or diesel ($18.50/GJ assumed). Using OCGT peaking plant reduces it slightly to $135 /MWh at 0.50 system ALF, albeit with less flexibility. That still represents very expensive electricity, particularly when only a minority of the energy is zero emissions, while the backup still emits CO_2. At more than 500 kg/MWh on a weighted average basis for diesel and more than 400 kg/MWh for natural gas, solar PV with thermal backup represents an uneconomic way of reducing emissions.

Large wind farms with open cycle gas turbines for backup are the lowest cost option at $125 to $135 /MWh, even with gas at $10/GJ. This combination is already playing a significant role in setting wholesale prices in the NEM. As with using small engines to back up solar, this technology pair still contributes material emissions of more than 300 kg CO_2 /MWh on a weighted average basis. While this appears to be an attractive interim strategy for emissions reduction, enhancement of wind turbines to provide ancillary services equivalent to synchronous generation increases their capital cost, increasing the levelised cost of the technology pair to the range $135 to over $150 /MWh for load factors between 0.50 and 0.75.

Wind farms backed by pumped hydro energy storage are estimated to deliver energy at between $175 and $300/MWh for load factors between 0.75 and 1. Matched to a load factor of one, five days of energy storage (120 hours or 120 MWh per MW of hydro generation capacity) would be required in the pumped hydro facility. In the case of a 0.75 load factor, about 10 days would be required. This is based on analysis of actual South Australian wind data.

Analysis of actual South Australian half-hourly load data from AEMO for 2015-16 (system load factor 0.49) and South Australian wind generation for the same period, shows that a pumped hydro storage of 2,500 MW backed by 14 days of storage would be needed if South Australian wind generation was scaled up to meet all in-state energy demand, allowing for losses in hydro pumping. Lower quality wind resources would require proportionately larger storage. Upgrading the wind turbines to be equivalent to synchronous generators would further increase this cost. The wind plus pumped hydro technology pair does provide zero emission electricity.

It should be noted that the above analysis has been performed at the generation level, and does not include additional transmission and distribution network costs that are likely to be required for VRE integration.

Conclusions

The full system costs of integrating VRE in the NEM cannot reliably be estimated by the LCoE approach that has been used to date. The LCoE approach is simplistic, unrealistic and does not provide an adequate foundation either for formulation of policy or for system planning.

The comparative approach outlined in this paper goes some way towards revealing the true costs of integrating VRE in the NEM in limited combinations of generation technologies. There is a strong implication of unaffordability in most options.

For example, the paper indicates that integration of VRE using zero emission storage solutions is very expensive, exceeding $175/MWh at the generation level, plus transmission costs. Costs exceed $250 /MWh once the need for synchronous generation for system stability is taken into account. Lower cost options, in the range $125 to $250 /MWh at the generation level, still involve emission levels of 300 to above 550 kg CO_2 /MWh on a weighted average basis. Meeting the need for synchronous generation to provide system stability at all times would further increase the costs but not reduce the emissions.

Cost estimates using traditional LCoE, indicating costs of $50 to $60/MWh or less for solar PV and wind, provide a misleading picture, because they fail to account for the costs of matching supply with demand, every second of every day, which is a fundamental for electricity systems.

There are many other important questions for policymakers and system planners flowing from the cost question that are beyond the scope of this paper.

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About the Author

Stephen Wilson *is Managing Director of Cape Otway Associates, which provides commercial and policy advisory services on energy and resources, economic analysis and strategy. An energy economist, he has 25 years of experience advising companies, banks, regulators and governments in Europe, Asia, Africa and Australia, on electricity and gas. Stephen has worked along the value chain from primary resource extraction through generation and transmission to energy efficiency and demand management, including regulation and electricity market design issues.*