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Least-cost modelling of electricity systems with a high share of weather dependent renewable generation

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Abstract: There is a diversity of findings on the cost of deploying a high share of weather dependent renewable generation technologies such as solar PV and wind for electricity generation. Differences in costs are mainly driven by the scope of the technologies and resources that the model data and design allow renewables to access. Renewables need to engage multiple strategies for their weather dependent production to be shaped so that electricity demand can be met reliably. Some published modelling only includes access to a narrow range of storage technology options, excludes access to a diversity of renewable generation profiles, or excludes the use of traditional fast response generation technologies such as gas turbines. This paper compares the scope of selected recent modelling on this topic and provides new modelling results which calculate the individual and cumulative impact of excluding various resources on the cost of systems with high shares of renewable generation.

Keywords: *Cost, renewable, generation*

1. INTRODUCTION

Published research on the costs of electricity systems with high renewable technology shares have delivered diverse results, some indicating renewables are low cost (Graham et al., 2025; Baik et al., 2021; Gilmore et al., 2023) while others find very high costs (Idel, 2022; Cross et al., 2023). In these studies, the focus is on the cost of deploying variable renewables which are weather dependent renewable generation technologies such as wind and solar PV. These variable renewable energy (VRE) technologies represent a change from the previous electricity sector paradigm of meeting electricity demand predominantly with flexible fuel-based technologies.

There are several common limiting factors which explain why some studies report high VRE integration costs. These include:

- Requiring that the VRE share be 100% or that all electricity sector emissions be completely eliminated. There is no such requirement in Australia under our net zero by 2050 emission target, nor is it common in other countries with a net zero target. Furthermore, going to 100% VRE would require the non-sensical step of shutting down existing non-variable renewable generation such as hydro and biomass generation in Australia. A 100% VRE requirement also denies renewables access to fast response generation technologies (peaking generation) such as open cycle gas turbines which are the most efficient technology for managing long periods of low renewable production but, because they are used infrequently, only result in a small amount of emissions.
- Limiting the types of storage technologies available to the system (e.g., only allowing batteries to participate, excluding other electricity storage options).
- Limiting the duration of storage technologies available to the system (e.g., only including one possible storage duration, excluding other durations).
- Limiting access of the system to realistically diverse renewable profiles (e.g., using just one generation profile for solar and one for wind).

Table 1 summarises the findings for the cost of generation from selected studies of systems with high VRE shares and the limits they have imposed. None of the studies reviewed included all of these limiting factors but they all included some degree of limitations on the resources that can be deployed with VRE. None of the studies provide strong justifications for excluding particular resources other than the desire to explore 100% decarbonisation in the case of exclusion of gas peaking. However, as discussed this was not justified by any reference to a specific policy requirement for that emission outcome. Technically all resources are available in most electricity systems globally. Some technologies could be restricted on political, social or environmental grounds as all technologies have some external impacts during their installation and operation. However, such issues were not emphasised in the studies included.

Costs are reported as the average cost of generation calculated as total costs divided by generation where only useful generation that meets demand, rather than spilled generation which can be a common outcome in high VRE systems, is counted in the denominator. The summary indicates that there is a very wide degree of cost estimates from just below $70 per megawatt hour (/MWh) to over $1000/MWh. The diversity of values can be explained by differences in the resources available to the system. For example, the most restrictive systems that were modelled and reported the highest system costs included limited diversity of VRE profiles, limited storage technologies and storage durations and limited access to gas turbines. Idel (2022) is the most restrictive of those listed in Table 1. However, this conclusion does not rely on comparing across studies alone. Rather, within each study, each author typically explores a less restrictive scenario and subsequently also reports finding lower system costs in these less restrictive cases.

Structural differences in the modelling are not the only factors driving results. Differences in costs are also a function of currency (US versus Australian dollars), inflation due to differences in the timing of studies, system scope and data inputs including technology costs in different countries. For example, Gilmore (2023) and Idel (2022) do not include transmission costs. US dollar costs are 40-50% higher in Australian dollars. There are four years between the oldest and most recent study, and this could account for around a 20% difference given this was a high inflation period. Technology costs often vary between studies but not greatly since technology cost data is shared by national and international institutions (for example IEA and NEA, (2020)). Overall, while these factors are not insignificant, the structural differences relating to resource availability are considered the strongest driver of differences in results and are the focus of this paper.

All the modelled results shown are for total electricity supply covering a diversity of customers (e.g. residential, commercial and industrial) in state level systems. Some research considers the cost of supplying 24/7 constant electricity supply for single customers such as heavy industry and data centres (Graham and Havas 2023). Where flat electricity supply is required, it is likely that VRE based supply will be more costly than supplying general residential and commercial customer demand. A comparison of the cost of supplying different customers with VRE is published in (ClimateWorks and ClimateKic, 2023).

Table 1 Comparison of modelled system cost results and limitations imposed on the scope of resources available for renewables

	Idel (2022)	Cross et al (2023)	Baik et al (2021) reported in DOE (2024)	Graham et al. (2025)	Gilmore et al. (2023)
Modelled system average cost	US$225-1380/MWh at 100% share. US$97-749/MWh at 95% share	A$101/MWh at 66%, A$192/MWh at 98% share	US$71/MWh for 45% to US$150/MWh for 100% share	A$76-168/MWh at 60% share up to A$90-176/MWh at 90% share	A$67-128/MWh for 100% share with different resources and weather years
Limiting use of fuel-based technologies such as gas turbines	Excluded in main case. A sensitivity allows for up to 5% share.	Up to 10% allowed across scenarios	Excluded. Scenarios include 100% renewables with batteries or lesser shares of renewables with either nuclear, carbon capture and storage (CCS), hydrogen or biofuel.	10% to 40% of energy can be sourced from any fuel-based technology	Only zero emission (biogas or hydrogen) gas turbines allowed
Limiting storage technologies	Only batteries are included	Only batteries are included	Only batteries are included	Lithium batteries, flow batteries, compressed air and pumped hydro storage included	Batteries and pumped hydro are included
Limiting the duration of storage technologies	Only 3-hour batteries are allowed	Only 4-hour batteries are allowed	Multiple battery durations allowed	Multiple durations for each storage technology	An optimal duration can be selected by the model for each technology
Limiting diversity of renewable profiles	Single profile each for solar and wind and highest cost results include use only solar or wind separately	Single profile for solar and wind per state	Range of Californian profiles	More than 30 profiles Australia wide	Ten wind and ten solar PV profiles for south east coast electricity system

This paper seeks to quantify the avoided cost from including each of the resources required to deliver least-cost high VRE share electricity supply. The cost of high VRE electric supply is studied in the context of meeting demand for electricity in 2050 in Australia's National Electricity Market (NEM) where the load shape varies half hourly, daily and seasonally and the electricity system must substantially reduce emissions to assist the nation in meeting its net zero by 2050 emission target.

The purpose in estimating these costs is to provide electricity stakeholders with a better understanding of how to interpret modelling results relating to the cost of systems with high VRE shares. Wherever a study excludes one or more resources, the modelling results in this paper can provide some guidance on how much the exclusion of those resources impacted the reported system costs.

2. METHOD

To model the high VRE share electricity system, a model developed by Graham et al. (2025) is used. The model was specifically designed to be the most simplified version of a model of NEM electricity supply that provides reliable results for the 2050 generation mix with a reasonably fast solve time. This makes the model ideally suited to modelling a large number of resource exclusions. The model is presented here without its equations or data sources. However, see Graham et al. (2025), which is being published to coincide with this paper, for those details.

2.1. Model description

The model is a linear program which minimises the cost of electricity supply in 2050 in meeting two hourly demand in each of fifteen regions of Australia's NEM by building and operating generation and storage technologies. Hydro is in included as an existing generation asset but for geographic and political reasons, there is no prospect for new capacity building and so the option to expand hydro capacity is excluded (with the exception of pumped hydro storage). Given their long asset lives, existing and committed pumped hydro and transmission are included in the model as existing 2050 capacity at no cost. Customer-owned batteries (both stationary and vehicles) are also supplied as existing capacity given their stock is constantly being replaced but the amount of that capacity assumed to be available at any moment to the system is highly filtered, consistent with AEMO (2023 and 2025). Otherwise, bedsides these exceptions, all current generation is assumed to have been retired by 2050. Electricity supply is constrained to meet a number of technical and spatial constraints as well as a minimum greenhouse gas emissions intensity of 0.05 tonnes of carbon dioxide equivalent per MWh (tCO_2e/MWh). This level of emissions intensity was chosen as a reasonable compromise between the need for very low emissions and cost of electricity.

2.2. Sensitivity cases

In the baseline, which is the most unconstrained implementation, Graham et al. (2025) finds that a combination of hydro (5%), solar PV (32%), onshore wind (55%), storage, and peaking gas (7%) are the least cost generation mix that meets the emissions intensity target of 0.05tCO_2e/MWh. It also includes an expansion of transmission connections between region and significant deployment of both battery and pumped hydro storage. Graham et al. (2025) also allowed for nuclear generation and coal or gas with CCS. However, neither was found to be part of the least cost generation mix.

Starting from this baseline, with all resources available for the most efficient deployment of a high VRE share of generation, the following sensitivity cases are implemented to determine the cost of removing selected resources:

- NoNewTransmission: new transmission to connect renewable energy zones to the grid is allowed since VRE generation at the scale required in 2050 would be impossible without it. However, new transmission between regions (i.e. to increase both intra- and interstate flows) is disallowed.
- NoGasPeak: The peaking technologies of gas turbines and gas reciprocating engines are disallowed
- NoH2Peak: Hydrogen peaking generation technology is disallowed
- NoPHES: New pumped hydro energy storage is disallowed. Existing capacity may be used.
- 4HourBatteryOnly: Batteries may only be deployed if they have four hours storage duration
- OneProfilePerState: The number of solar PV, onshore wind and offshore wind profiles per state is reduced to one per state compared to up to four per state
- SolarPVOnly: Solar PV is the only type of VRE generation technology that may be selected. Alternatively, onshore and offshore wind could have been selected as the only VRE generation options, but solar PV only is the more restrictive case since solar PV generation profiles are more coincident between regions.

The choice of which resources to remove is based on resources that were commonly removed in previous studies such as those listed in Table 1 and the author's experience of what resources tend to be most valued in high VRE electricity systems. These sensitivity cases are implemented both one by one to determine their individual impact and cumulatively (in the order presented above) to determine their combined impact.

3. RESULTS

Figure 1 shows modelling of the average system cost increases, relative to the baseline with all resources included, that result from individually removing selected resources that support high VRE share generation in the Australian NEM in 2050. The removal of the option to deploy wind generation in the total VRE generation mix is the highest cost of the eight sensitivities adding $47/MWh which is more than twice the impact of excluding any other resource.

The second largest cost increase is $23/MWh as a result of removing the option expand transmission capacity between regions. The third largest cost increase is from removing the option to deploy gas peaking technologies at $16/MWh. The remaining cost increases from highest to lowest are OneProfilePerState ($8/MWh), NoPHES ($8/MWh), 4HourBatteryOnly ($6/MWh) and NoH2Peak ($0/MWh). The cost of excluding hydrogen peaking plant is zero because it was not part of the least cost generation mix to being with. However, this zero emission alternative to gas peaking can be an important contributor to high VRE generation when gas peaking is unavailable (Gilmore et al., 2023).

The limited impact of the removal of new storage options on the average system cost reflects that less optimal storage technologies can still be deployed. Also, the restrictions only apply to new storage, whereas the system may continue to use the assumed existing and committed pumped hydro and battery storage.

With the removal of each option, the VRE share increases or decreases depending on what is the new least cost generation mix when each resource is taken away individually. With NoNewTransmission and NoGasPeak, the non-VRE share increases since it is more difficult to access renewables from other regions without new transmission and more expensive to back them up during prolonged low production without gas peaking technologies. In place of renewables there is an increase in combined cycle gas generation. The remaining sensitivity cases do not significantly change the VRE share. This reflects that removal of those resources has not increased the cost of VRE deployment enough for the model to preference increased capacity of another technology such as combined cycle gas.

Figure 1 Changes in average system cost and VRE share from individually removing selected resources that support efficient high VRE share generation in the Australian National Electricity Market in 2050

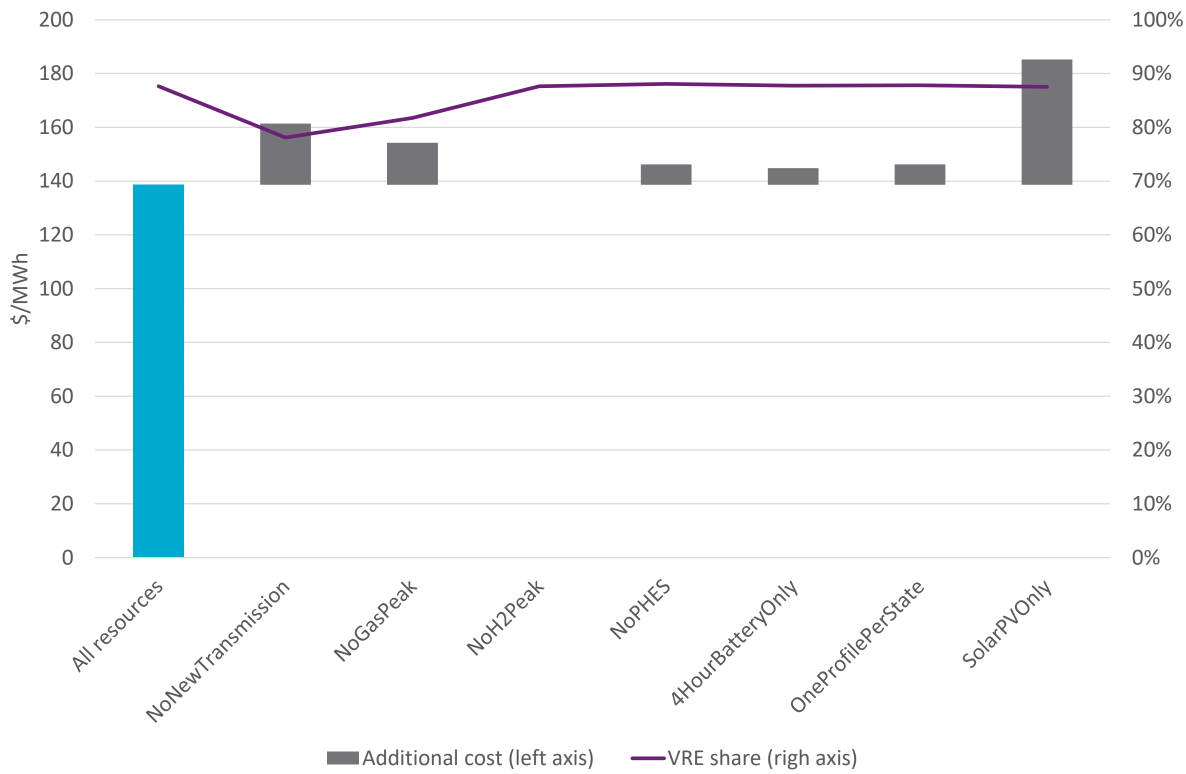


Figure 2 shows the changes in average system from cumulatively excluding selected resources in a specific order. The order of exclusion, of course, impacts how important each exclusion is since the removal of one or more resources increases the value to the system of any remaining resources. The impact of cumulatively applying the exclusions of NoNewTransmissn and NoGasPeak is an increase in costs of $31/MWh. The exclusion of these resources has resulted in a system that has decreased its VRE share from 88% to 79% and hydrogen peaking plant now supplies 6% of generation compared to not being needed at all when all resources are included. When the NoH2Peak sensitivity is explored in addition to the previous exclusions, this removes hydrogen peaking plant, resulting in no deployment of any type of peaking generation technologies. The resulting average system cost is increased by $132/MWh relative to the cost when all resources are included. The cumulative addition of NoPHES, 4HourBateryOnly, OneProfilePerState and SolarPVOnly increase costs relative to the cost when all resources are included by $137/MWh, $152/MWh, $200/MWh and $241/MWh respectively.

The total average cost of generation when the full range of resource restriction are introduced is $379/MWh. This is higher than all of the studies listed in Table 1 except Idel (2022). However, the highest range of costs reported in Idel (2022) not only excluded all generation other than solar PV but also any other technology except battery storage such that solar PV provided 100% of the electricity supply. Australia's National Electricity Market has existing hydro generation as well as existing and committed pumped hydro storage capacity which are both long-lived assets and therefore would still be expected to be available in 2050. Also, while the combined sensitivity cases excluded peaking generation and new pumped hydro storage, gas combined cycle generation is not excluded in modelling presented here. Together, hydro and gas combined cycle generation contribute 6% of generation in

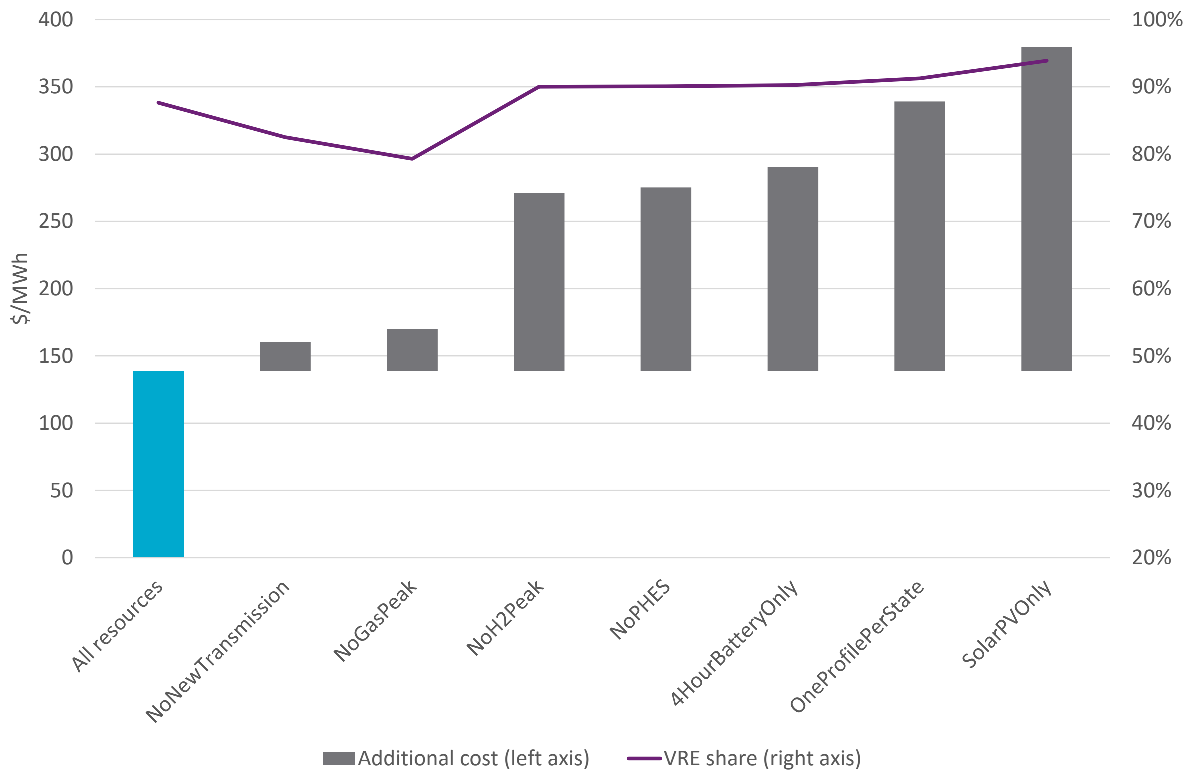
SolarPVOnly (when combined with all other exclusions cases) with solar PV providing 94%. As such this is not as extreme as Idel (2022) and explains why costs are not as high as found in that study for a solar PV only generation system.

The remaining studies fall within the cost range presented in Figure 2 and generally do not exceed $200/MWh. With the exception of Idel (2022), most studies in Table 1 do not apply or exceed all the resource restrictions included in the sensitivity cases explored here which explains why the highest cost presented in Figure 2 exceeds the remainder of studies in Table 1.

During the cumulative deployment of resource restrictions, the VRE share initially declines because the removal of resources makes a high VRE share more expensive. However, as restrictions are placed on non-VRE technologies such as peaking gas, the options for achieving the required electricity system emission intensity are more limited and the VRE share increases to a peak of 91% before the removal of the option to deploy onshore and offshore wind. When only solar PV may be deployed, the VRE share increases further to 94%. This last increase is likely because it becomes difficult to deploy gas combined cycle with so much solar PV generation in the system. Gas combined cycle generation has a minimum stable generation requirement of 46%. This requirement is more easily achieved by the system, the more diverse the VRE supply as it reduces total VRE electricity generation that must be spilled to achieve minimum gas combined cycle generation during periods of high VRE supply.

Prior to excluding onshore and offshore wind in SolarPVOnly, the role of offshore wind increased the greater the resource restrictions imposed peaking at 25% of generation across the sensitivities. Offshore wind is normally not preferred as it is higher cost than onshore wind. However, with limited transmission between regions and fewer peaking and storage technologies offshore wind has the advantage of being close to demand centres and a higher capacity factor which reduces the capacity of storage needed to meet demand.

Figure 2 Changes in average system cost and VRE share from cumulatively removing selected resources that support efficient high VRE share generation in the Australian National Electricity Market in 2050



4. DISCUSSION AND CONCLUSION

Modelling on the cost of high VRE share electricity generation systems has a very wide range with some studies reporting relatively modest costs while others alarmingly high costs. Very few electricity modelling studies will have the same data inputs and may differ in other ways such as scope of the system and country of origin. However, the resources that are assumed to be available in the electricity system to efficiently achieve a high VRE share does differ significantly between studies and can be a source of large differences in estimated system costs. Some published modelling only allows for access to a narrow range of storage technology options, excludes access to a diversity of renewable generation profiles, or does not allow the use of peaking generation technologies. Selected studies have been compared to demonstrate the types of resource restrictions typically imposed.

Using an Australian electricity system model, new modelling results are provided which calculate the individual and cumulative impact of excluding various resources on the average cost of electricity in high VRE share systems. The goal of this modelling was to determine how these exclusions impact reported costs so that the divergent findings on the costs of high VRE share electricity systems may be better understood. The results find that the removal a single resource, across the range of sensitivity cases included, lead to increases in costs in the range of $6/MWh to $47/MWh. However, cumulatively, the exclusion of many resources led to up to a $241/MWh or 174% increase in costs. The maximum increase in costs did not include the most restrictive assumption found in previous studies which was to remove any other options other than solar PV and batteries. This was considered implausible in Australia's NEM which includes existing long-lived hydro and pumped hydro capacity.

The implications of these modelling results are that the exclusion of resources that can assist electricity systems in meeting high VRE shares inflates the estimated average cost of electricity in those systems. Therefore, such exclusions should be avoided unless they can be justified in some way. In Australia's electricity system, none of the exclusions are justifiable on technical grounds since all these options exist from a technical standpoint. Political, social and environmental constraints may be valid, but did not appear to be a significant motivator for the exclusions in the studies reviewed. Some restrictions are necessary to explore 100% VRE share scenarios, but such scenarios are principally of academic interest since the goal of Australia's and many other country's climate policies are defined in terms of net zero emission targets which do not require the electricity sector or any other specific sector to completely eliminate emissions.

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