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A change in the air? The role of offshore wind in Australia's transition to a 100 % renewable grid

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ABSTRACT

Rapid decarbonisation of electricity production is required if Australia is to meet its obligations under the Paris Agreement. Critical to achieving this at low cost while maintaining system reliability is the selection of an appropriate mix of generation technologies to service electrical demand. Australia has seen extensive deployment of renewable energy technologies such as onshore wind and solar but has not yet seen the adoption of offshore wind technology. However, there is currently significant interest in developing this resource, with ongoing debate occurring about future technology costs and the potential of onshore renewables to meet electrical demand.

This article presents the results of an investigation into the techno-economic impact of exogenously fixing offshore wind capacity on a future least-cost Australian National Electricity Market with 100 % renewable generation. An existing open-source cost optimisation model, National Electricity Market Optimiser, was used for the study.

It was found that increasing the capacity of offshore wind in the generation mix leads to displacement of both onshore wind and solar generators. This is due to the greater magnitude and consistency of the offshore wind resource relative to onshore. Increasing offshore wind capacity therefore tends to reduce the total system generation capacity, as well as the amount of unused surplus generation. Using lowest published projections for future capital costs, inclusion of offshore wind was found to reduce total system costs. Using an average of future cost projections, total system costs were found to increase. However, adding up to 15 GW of offshore wind capacity to a 100 % renewable system would only impact total system costs by 5 %. Given the other potential advantages of offshore wind, namely closer siting to load centres, reduced need for onshore land resources, and the potential to transition existing fossil fuel workers, our results suggest that offshore wind may be a suitable candidate for inclusion in Australia's transition to a low carbon electricity system, under a range of future cost scenarios.

1. Introduction

Countries across the globe are aiming to reduce their greenhouse gas (GHG) emissions in the first half of this century to meet their international obligations under the Paris Agreement and avoid the worst effects of climate change. The current consensus is that a reduction to zero emissions must take place by around 2050 to have a chance of limiting warming to 1.5 °C (Espinosa, 2020). Given that emissions in some sectors of the economy are harder to abate than in others, it is likely that decarbonisation of electricity systems will need to occur prior to 2050. Pre-emptive decarbonisation of the electricity system will enable emissions reductions across the economy through electrification and the production of clean energy carriers such as green hydrogen.

Australia's emissions from electricity and heat production (EHP) are currently decreasing, while 'gross emissions' are increasing. The data from (Data) plotted below demonstrates this (Fig. 1). By gross emissions we refer to Australia's total GHG emissions minus discounting from land use, land use change and forestry (LULUCF). The ongoing increase in Australia's gross emissions, despite a reduction of GHG emissions from EHP, indicates that decarbonisation of EHP alone is insufficient to create the necessary trend to reach net zero emissions by 2050. This aligns with findings in the literature that the Australian economy will require

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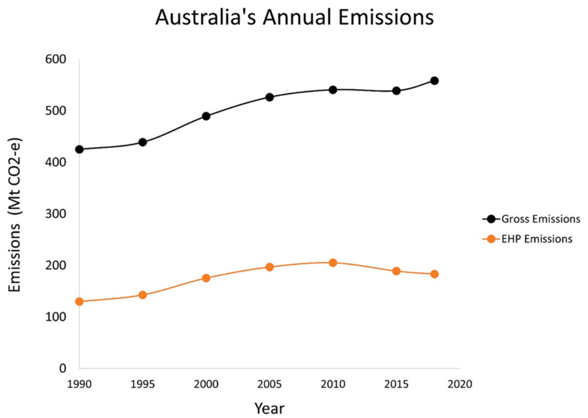

Fig. 1. Australia's gross and EHP emissions excluding LULUCF (Data).

Fig. 2. Bathymetry data for the Australian coastline in metres (Global Wind Atlas, 2020).

pre-emptive decarbonisation of the electricity system to reach net zero by 2050, with decarbonisation of the National Electricity Market (NEM) needing to occur by 2035–2037 (Butler et al., 2020; Pascoe and Caught, 2014).

Previous research (Elliston et al., 2014; Blakers et al., 2017; AEMO, 2013) also suggests that it is feasible and cost-effective to decarbonise the NEM by using 100 % renewable electricity. We therefore chose to investigate a 100 % renewable NEM for a period beginning in 2037. Previous studies into a 100 % renewable NEM have excluded offshore wind as a potential generation technology. Historically offshore wind in Australia has been expensive relative to other renewable energy technologies. This, however, is changing due to the increased deployment of offshore wind technology internationally and corresponding cost reductions. Wind turbine technologies maturing before 2030, such as turbines capable of deployment in shallow and transitional water depths, are likely to become cost competitive with other mature forms of generation technology (CO2CRC, 2015).

Furthermore, the development of mega-turbines and turbines suited to deep waters will enable offshore wind deployment to occur economically across a wider range of geographic locations. This is particularly relevant in the Australian context, due to the deep waters close to the eastern coast. Fig. 2 was obtained from (Global Wind Atlas, 2020), and shows bathymetry data up to 100 km offshore, with the scale spanning seafloor depths of 0–100 m below sea level. Note that depths in the offshore region exceed 100 m but variation of these depths is not shown due to the choice of scale.

As offshore wind technology matures it will increasingly become an economically competitive generation technology. The International Renewable Energy Agency predicts that the internationally market for offshore wind will "grow significantly over the next three decades, with the total installed offshore wind capacity rising nearly ten-fold from just 23 GW in 2018 to 228 GW in 2030″ (IRENA, 2019). The Australian Energy Market Operator (AEMO) regularly updates its planning process to ensure that the competing objectives of system reliability and electricity affordability are balanced while Australia's electricity system transitions to a lower carbon future. In 2021, AEMO added four offshore wind zones (OWZs) to its planning process, with a nominal capacity of 10 GW per OWZ (AEMO, 2021). This is further indication that offshore wind technology can be considered a mature technology, even in emerging markets such as Australia.

Offshore wind has advantages independent of these market and cost developments. For example, the offshore wind resource is higher and more consistent relative to onshore. These characteristics of the offshore wind resource result in higher capacity factors, which can help reduce Levelized Cost of Energy (LCOE) to more competitive levels. Offshore wind may also present opportunities to transition existing fossil fuel workers from industries such as offshore oil and gas. In the Australian context, offshore wind has the added benefit that it can be sited close to the major population centres which are all coastal, potentially reducing transmission costs. Furthermore, the reduced land impacts of offshore wind projects compared to onshore wind and large-scale solar generation, may reduce the challenge of securing social licence for the energy transition.

This study uses AEMO's planning framework as the basis for an investigation into the techno-economic impact of including offshore wind in Australia's energy transition. This study focuses on three of the four OWZs outlined in the 2021 planning documentation: O2 – Illawarra Coast, O3 – Gippsland Coast, O4 – North-West Tasmanian Coast (AEMO, 2021). AEMO's planning scenarios are constrained by the existing transmission networks and the currently operational generation assets (including fossil fuelled generation), limiting the applicability of their findings to the specific context of the current day NEM without investigating future least cost generation portfolios. However, the future cost-optimised NEM is not constrained by current generation assets or network configurations. In order to provide insights into the use of offshore wind in a manner which is independent of existing fossil fuel assets and provides information which may be applicable to the international community, we investigated the relationship between exogenously fixed offshore wind capacity and the annualised system cost of a future cost-optimised 100 % renewable electricity system. This study modelled the deployment of onshore wind technology, solar generation, and biogas, optimised through the use of an evolutionary algorithm. This enabled exploration of the dependence of optimal deployment of offshore wind and other generation technologies on the basis of capital and operational costs. The modelling method is described in Section 2, the results are discussed in Section 3 and conclusions are presented in Section 4.

2. Methods

The modelling undertaken in this study relies on a modified version of the open-source National Electricity Market Optimiser (NEMO) tool. NEMO carries out a constrained optimisation, using an evolutionary algorithm to search for a least cost solution (LCS) to meet AEMO's reliability standard of 0.002 % unserved energy per year (AEMO, 2012), while avoiding the use of fossil fuel in electricity production. The following sections describe NEMO and the modifications made to it for this study. For a detailed description of NEMO please refer to Elliston et al. (2013).

Table 1
Implementation of OWZs in NEMO.

AEMO's OWZ	Location	NEMO Polygon
O2	Wollongong	36
O3	Gippsland	38a
O4	NW Tasmania	39

2.1. Modelling approach

NEMO is a chronological dispatch model which can be used to optimise portfolios of electricity generators in the NEM (CEEM UNSW, 2020). It models a wide range of renewable and fossil generation technologies including wind, solar PV, concentrating solar thermal, biomass, geothermal, coal, open cycle gas turbines, and so on. The required inputs to NEMO are summarised below:

- Hourly 1 MW trace files for weather-dependent generators – specified for each polygon in the NEM. The polygon framework divides the geographical area serviced by the NEM into 43 polygons, for further information on the framework refer to AEMO (2012)
- Hourly demand profile for each of the five regions in the NEM for a given timeframe (e.g., one year)
- Cost data for each technology: capital costs ($/kW), fixed operations and maintenance or O&M (FOM, $/kW/year), and variable O&M (VOM, $/MWh).
- Details of existing pumped hydro energy storage (PHES), battery energy storage system (BESS) and hydropower assets in the NEM.
- Realistic constraints on annual electricity from bioenergy and hydropower.
- A limit on the instantaneous non-synchronous penetration (NSP) allowed in the NEM to provide sufficient inertia for frequency control.
- The hours of the day in which battery energy storage system (BESS) assets can discharge their stored energy.

Using these inputs, the model performs an electricity production cost optimisation using an evolutionary algorithm known as the covariance matrix adaptation evolution strategy (CMA-ES) (Elliston, 2021). This evolution strategy iterates through solutions by varying the mean of the test solution parameters (i.e., the parameters representing the capacity of each simulated generator), to reach a goal (Dang et al., 2019). NEMO has a fixed goal, which is to achieve the lowest fitness score, defined as the sum of:

1. total annualised capital cost of generating capacity.
2. total fixed O&M costs for the year.
3. total variable O&M costs for the year.
4. estimated cost of transmission.
5. penalty functions (for unmet constraints, e.g., bioenergy limits) (Elliston et al., 2013)

As the transmission cost is included in the simulation framework, the annualised $/MWh value includes both generation and transmission costs. Transmission costs are estimated at $800/MW-km and the calculation of annualised transmission network costs uses an asset lifetime of 50 years, while generators are assumed to have a lifetime of 30 years (Elliston et al., 2013). A real discount rate of 5 % was used for NEMO's calculation of the annualised system cost. Previous studies indicate that the generation mix is not particularly sensitive to the discount rate (Elliston et al., 2013).

Nine separate optimisations were conducted to determine if a relationship exists between annualised system cost and exogenously fixed offshore wind capacity. These nine optimisations can be categorised under three groups: a control run without offshore wind, four optimisation runs including offshore wind at an average capital cost scenario, and four optimisation runs including offshore wind using the lowest capital cost scenario. The optimisations which include offshore wind are characterised by the amount of offshore wind capacity set, with offshore wind being varied from 2.5 GW to 10 GW per OWZ in steps of 2.5 GW. As only three of the four OWZs were studied, this approach led to optimisations occurring for the following total amount of fixed offshore wind capacity: 0 GW, 7.5 GW, 15 GW, 22.5 GW, 30 GW. The results were obtained by using 250 generations in the evolutionary algorithm for each of the nine scenarios.

2.2. Modifications to NEMO

A new offshore wind generator class was added to NEMO to model the inclusion of offshore wind in the NEM. This enabled the existing class of onshore wind generators and the new offshore wind generators to have different costs. In order to reflect AEMO's OWZ framework, offshore wind was specified for three polygons which correspond to three OWZs (Table 1).

Fixed generators were added to the scenarios to represent existing PHES and hydrogeneration assets (shown in Table A.1). Additional BESS asset capacity was set in the model to better reflect the operating conditions of a potential future NEM in 2037. Note that the capacity of PHES and hydropower were limited to existing capacities, but not otherwise fixed in NEMO, and they are freely optimised based on having no capital or O&M costs. BESS capacity was fixed as per Table A.2; however, NEMO manages BESS dispatch. The modelling inputs are discussed further in Sections 2.3 and 2.4.

2.3. Modelling inputs and assumptions

A common reference year was used in order to model a future NEM in a year beginning in 2037, while using readily available demand and generation data. This approach follows AEMO's recommendation that trace files for demand and generation be based on the same period so that any temperature-related correlation is not lost (AEMO, 2020). One year of demand data, from 1 July 2037 to 30 June 2038, was used from AEMO's 'central scenario' demand from the 2020 Integrated System Plan (ISP) (AEMO, 2020). Following AEMO's reference year pattern, the generation files used in this study covered the period 1 July 2010–30 June 2011 (AEMO, 2020). The generation trace files used originate from the files generated by ROAM Consulting for AEMO's 2012 study into a 100 % renewable NEM (ROAM, 2014).

- The 2020 ISP 'Central Scenario' data for 2037 contains only the operational demand 'sent out'. This demand can be thought of as the electricity demand caused by residential, commercial, large industrial consumers and electrical losses, as supplied by generators over 30 MW. Some exceptions apply; for example, the demand supplied by Batteries over 5 MW is included in operational demand. Thus, demand met by residential photovoltaic (PV) systems, PV Non-Scheduled Generators (systems between 100 kW and 30 MW), and residential battery systems are not included in operational demand (AEMO, 2020).
- NEMO requires normalised (1 MW) trace files for variable renewable technologies such as PV and wind generators. ROAM's trace files were used to model generation from single axis tracking utility solar, onshore wind, and offshore wind (ROAM, 2014).
- Battery dispatch was limited to outside solar hours i.e., BESS dispatch could occur between 12–6 am and 6–11 pm.
- Due to the increasing ability of batteries and inverter-based technologies to assist in the management of grid frequency through services such as synthetic inertia and fast frequency response, the NSP was set to 95 %. While it is acknowledged that this NSP limit is ambitious relative to the current operating parameters of the NEM, it is plausible that by 2037 it will be possible to achieve this. AEMO has stated that "advanced inverters could provide capabilities to support

Table 2
2037 projections for offshore wind capital costs.*

Study	Offshore Wind Capital Cost ($/kW)
ClimateWorks (ClimateWorks, 2014)	3870
IRENA - Upper Bound (IRENA, 2019)	4472
IRENA - Lower Bound (IRENA, 2019)	2331
CSIRO GenCost – High VRE (Graham et al., 2020)	5257
BEIS (BEIS, 2020)	2236

*ClimateWorks figure was obtained via linear interpolation of the 2030 and 2040 costs. IRENA figures use a conversion factor of AUD to USD of 0.69 and were obtained via linear interpolation of the 2030 and 2050 costs. The BEIS cost uses a conversion factor of AUD to Pound sterling of 0.55.

Table 3
Capital cost of mature generation technologies.

Technology	Capital Cost ($/kW)
Battery (Aurecon, 2020)	300
Utility Solar(Single Axis Tracking) (Graham et al., 2020)	647
Biogas[a] (Graham et al., 2020)	1414
Onshore Wind (Graham et al., 2020)	1756
PHES	0
Hydropower	0

[a] All biogas costs are based on the costings of open cycle gas turbines.

Table 4
O&M costs of generation technologies.[a]

Technology	FOM [$/kW/year]	VOM [$/MWh]	Additional costs
Battery (Aurecon, 2020)	14.5	0	300 $/kWh (storage)
Utility Solar(Single Axis Tracking)(Australian Bureau of Resources and Energy Economics, 2013)	34	0	0
Biogas	5 (Australian Bureau of Resources and Energy Economics, 2012)	12 (Australian Bureau of Resources and Energy Economics, 2012)	14 $/GJ(fuel)(James and Hayward, 2012)
Onshore Wind (Australian Bureau of Resources and Energy Economics, 2013)	37	11	0
Offshore Wind (Valpy and English, 2014)	46	14	0
PHES	0	0	0
Hydropower	0	0	0

[a] The total O&M costs for offshore wind align with an average of the low to mid- range costs from the study by Valpy and English (2014).

the secure operation of a synchronous power system like the NEM" (AEMO, 2021).

- PHES and hydropower assets are assigned zero capital costs, as they are assumed to be existing assets in the NEM with significant lifetimes and sunk costs. As these assets are assumed to be exogenously fixed for 2037, they are not included in the cost-optimisation. This assumption enables NEMO to optimise fewer parameters and converge more quickly on the least-cost NEM generation fleet i.e., to optimise the additional generation assets required to create a least-cost grid in 2037.

2.4. Technologies and costs modelled

As discussed in Section 1, the expected maturation of offshore wind technology presents significant scope for offshore wind cost reductions in the near future. Thus, one of the key variables for this study was the capital cost for offshore wind technology. The substantial variation in published projections for offshore wind capital costs (Table 2) makes this selection challenging. Furthermore, offshore wind projects can take a long time to develop, with an Australian project expected to take 6–10 years to reach completion (Star of the South, 2021). It is therefore possible that an offshore wind project built to be operational in 2037 will not use the most cost-effective turbines due to previous contractual arrangements. These cost uncertainties were addressed in the study by using two cost settings for offshore wind capital costs, one based on the average of projected costs and the other based on the lowest projected cost (see Table 2). All costs are shown in 2020 Australian dollars (AUD).

It is noted here that capital cost projections from ClimateWorks and the Commonwealth Scientific and Industrial Research Organisation (CSIRO) GenCost reports are derived from an Australian perspective,

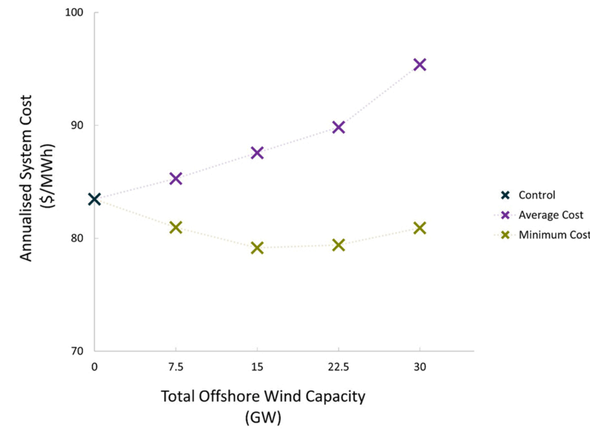

Fig. 3. Annualised system cost of LCS vs exogenously fixed offshore wind capacity in the NEM.

Table 5
Relative cost of each offshore wind scenario under average cost scenario.

Offshore Wind Capacity (GW)	Annualised System Cost ($/MWh)	Increase Relative to 0 GW Offshore Wind (%)
0	83.46	–
7.5	85.29	2.19
15	87.57	4.92
22.5	89.83	7.63
30	95.39	14.29

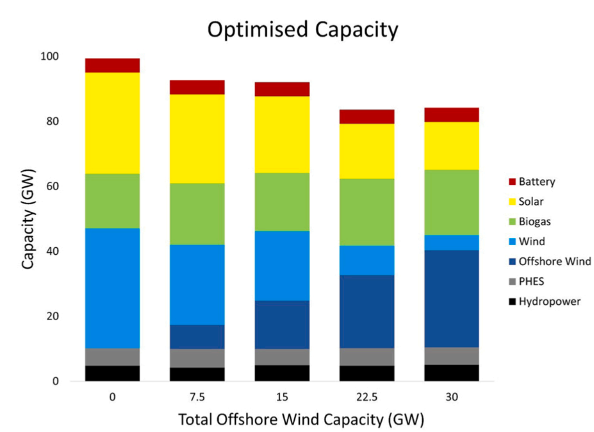

Fig. 4. Optimised capacity breakdown for the control and average cost offshore wind scenarios.

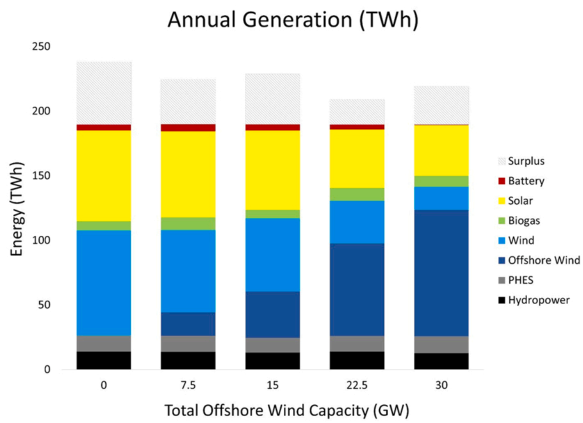

Fig. 5. Annual generation breakdown for the control and average cost offshore wind scenarios.

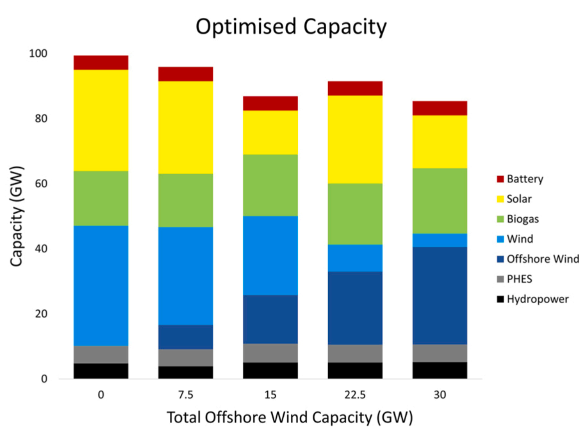

Fig. 6. Optimised capacity breakdown for the control and minimum cost offshore wind scenarios.

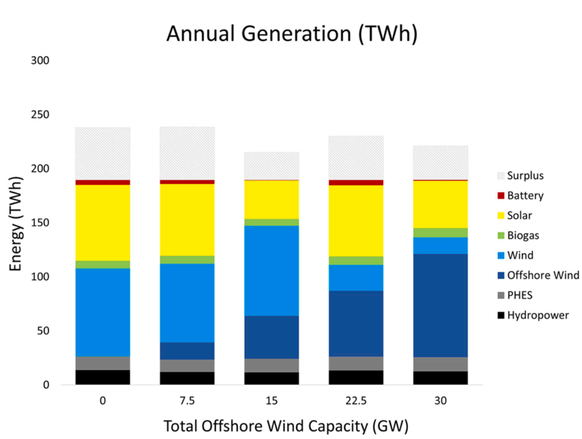

Fig. 7. Annual generation breakdown for the control and minimum cost offshore wind scenarios.

while the projections from the International Renewable Energy Agency (IRENA) were developed using a global outlook. The high variable renewable energy (VRE) figure from the CSIRO's GenCost report was used as these figures are in line with limiting global warming to 2 °C. The last row in Table 2 is from the UK's Department for Business, Energy and Industrial Strategy (BEIS). To reflect the potential for Australian costs to fall in line with international values, both Australian and international projections were used for the development of the costing scenarios. The conversion of historical prices to 2020 AUD was performed using the Reserve Bank of Australia (RBA) Inflation Calculator (RBA).

Averaging the capital cost figures of Table 2 gives a 2037 capital cost projection of 3633 $/kW. This figure was used for offshore wind in the average cost scenario, capturing the potential of the technology to decrease relative to the more conservative estimates. A cost of 2230 $/kW was used for the minimum cost scenario. For the more mature generation technologies with significant deployment in the Australian context, and therefore less uncertainty in their future cost projections, the CSIRO's 'High VRE' scenario costings were used, shown in Table 3.

The O&M costs of each technology are shown in Table 4. Some technologies have cost parameters beyond capital and O&M costs (i.e., fuel costs or costs related to the hours of storage), which are captured in the additional costs column.

3. Results and discussion

3.1. Annualised system costs

The relationship between exogenously fixed offshore wind capacity and annualised LCS system cost, for both the average and minimum capital cost scenarios, is shown in Fig. 3, with the nine optimisations categorised under three groups: control, average cost, minimum cost.

Fig. 3 demonstrates that, under the average capital cost projection for offshore wind, the annualised system cost increases continuously with increasing additions of offshore wind capacity, with the cost increase being approximately linear until fixed offshore wind capacity reaches 22.5 GW (7.5 GW per OWZ). The linear relationship found in the range of 0–22.5 GW, indicates that increasing offshore wind capacity in steps of 7.5 GW caused a 2.2–2.7 % increase in LCS cost. As the amount of exogenously fixed offshore wind in the NEM increases, NEMO is unable to find a LCS which reaches the same cost as the control offshore wind scenario, if the capital cost of offshore wind is priced at 3633 $/kW. The annualised system costs for the control and average costing optimisations are shown in Table 5, alongside the percentage cost increase caused by the addition of offshore wind capacity under the average costing. The percentage increase in annualised system cost of the 7.5 GW and 15 GW average cost optimisations may not be prohibitive if decision makers are willing to accept some amount of cost increase relative to the control LCS.

Fig. 3 also demonstrates that the inclusion of offshore wind reduces annualised system costs relative to the control scenario under the minimum capital cost projection of 2230 $/kW. This demonstrates that, under favourable cost projections, significant amounts of offshore wind could be included in the NEM while simultaneously bringing down system costs. All four LCS optimisations under the minimum offshore wind cost scenario produced system costs which are at least 3 % less expensive than the control scenario. The two lowest cost solutions occurred when the amount of offshore wind in the NEM was fixed to either 15 GW or 22.5 GW under the minimum cost scenario, producing annualised system costs of 79.16 $/MWh and 79.40 $/MWh respectively.

Fig. 3 should not be used in isolation for an analysis of the economic merits of including offshore wind in the NEM. The reasons for this are twofold. Firstly, the fixing of offshore wind capacity changes the deployment of other generation technologies in the simulated NEM, as discussed below. Secondly, other considerations, such as the concerns of local communities, and the infrastructure already existing in the NEM can have economic implications and should also inform policy decisions. The results of the average cost scenario optimisations are discussed in Sections 3.2 and 3.3, while the results of the minimum cost scenario optimisations are discussed in Sections 3.4 and 3.5.

3.2. Installed capacity for each LCS under average capital cost scenario

The capacity breakdown for each scenario is presented in Fig. 4, which shows how varying the amount of fixed offshore wind capacity changes the composition of the LCS. (A detailed capacity breakdown is presented in Table B.1). Varying the amount of fixed offshore wind capacity also changes the total capacity required to meet the NEM's electrical demand.

The total amount of wind technology included in the LCS (i.e., onshore wind + offshore wind) remains relatively constant across all five scenarios with an average of 34.3 GW ± 2.7 GW. With both offshore and onshore wind having similar variable costs, these two technologies compete with each other in the merit order based on their LCOE. Total wind capacity stays relatively constant even though increasing amounts of fixed offshore wind capacity decreases the total amount of capacity required to service electrical demand. The decrease in total capacity of the LCS is driven by the decreased installation of both solar and onshore wind capacity. Because the offshore wind resource is stronger and more consistent than the onshore wind resource, less solar and onshore wind is required as the demand is increasingly met by offshore wind.

It is interesting to note that the control LCS (with zero offshore wind) has the highest total capacity. The control LCS is able to maintain low costs while having a high total capacity because onshore wind and utility solar generators have low capital and O&M costs. The affordability of the electricity generated by these technologies is reflected in the LCOE achieved. In the 0 GW control LCS, solar is able to achieve an LCOE as low as 26 $/MWh, while the cheapest LCOE from onshore wind is 67 $/MWh (also in the control scenario). In contrast, the lowest LCOE achieved by offshore wind is 81 $/MWh (achieved in the 30 GW offshore wind scenario). Although the lowest achievable LCOE for offshore wind is significantly higher than that achieved by onshore wind, it can be included in the NEM without causing prohibitive cost increases to annualised LCS cost, as offshore wind displaces the need for generation from solar as well as onshore wind generators. This trend was broken for the 30 GW offshore wind optimisation, as NEMO was unable to converge on a LCS with reduced capacities from other generation sources. In addition to cost savings from displaced generators, exogenous offshore wind also has the potential to reduce transmission networks costs.

3.3. Annual generation for each LCS under average capital cost scenario

The generation breakdown for the year 2037–2038 under the average cost scenario is shown in Fig. 5, with the amount of unused surplus generation also included. Unused surplus is the generation in excess of electrical demand which was not able to be stored in either PHES or BESS. In practice, this energy would be curtailed. A detailed breakdown of annual generation is presented in Table B.2.

Fig. 5 shows that solar and onshore wind generation generally follows a similar pattern to their capacity across the different offshore wind scenarios, as described in Section 3.2. A comparison of Fig. 5 to Fig. 4 reveals an increase in total wind generation (i.e., onshore wind + offshore wind) as the capacity of fixed offshore wind increases, while total wind capacity remains relatively constant. This is reflective of the fact that the offshore wind resource is more productive than onshore, thus as the fraction of offshore wind capacity increases more energy can be produced throughout the year. The different capacity factors (CFs) achieved by wind technologies is evidence of this phenomena. In the 0 GW control scenario the highest CF achieved by onshore wind is 30.8 %, while offshore wind can achieve CF up to 47.8 % in the 30 GW scenario. Note that these CFs are based only on the electricity which directly services demand, i.e., they exclude generation stored by BESS and PHES assets.

It should also be noted that the 0 GW control scenario has the highest unused surplus energy throughout the year, but still provides a lower annualised system cost relative to the offshore wind optimisations using an average capital costing. The 0 GW control optimisation produces greater surplus generation while remaining cost effective due to the low LCOEs of solar and onshore wind generation, as discussed in Section 3.2. Previous work on 100 % renewable scenarios (Elliston et al., 2014) has shown that building additional capacity, which may lead to curtailment at times, can be a cost-effective way to achieve resource adequacy compared to other measures such as storage.

3.4. Installed Capacity for each LCS under minimum capital cost scenario

The capacity breakdown for the control and minimum capital cost optimisations is presented in Fig. 6, showing a trend similar to that of the average cost scenario. A detailed breakdown of the installed capacity is presented in Table B.3. A further similarity between the average cost and the minimum cost scenarios is that the total amount of wind technology included in the LCS remains relatively constant across all optimisations, with an average of 35.7 GW ± 3.0 GW.

A point of contrast between the two cost scenarios is the increased variation in total installed capacity in the minimum cost scenario (Fig. 6). As offshore wind can now be included in the LCS without increasing system costs, there is less of a need to reduce total capacity to compensate for the inclusion of offshore wind. This is highlighted by the differences in the lowest LCOE achieved by an offshore wind generator, which was 81 $/MWh in the average cost scenario but only 60 $/MWh in the minimum cost scenario, which is comparable to the LCOE of onshore wind. This enables lower system costs despite the greater total capacity in comparison to the relevant average costing counterpart.

Both the 15 GW and 22.5 GW optimisations produce similar annualised system costs in the minimum offshore wind capital cost scenario. Interestingly, the contrast between the installed capacities suggests that either high amounts of onshore wind and small amounts of utility scale solar, or small amounts of onshore wind and high amounts of solar can be paired with offshore wind to produce favourable LCS cost outcomes. Although increasing offshore wind capacity generally decreases the need for onshore wind in the LCS, offshore wind can also be paired high amounts of onshore wind in the LCS given a reduction in other generation capacity.

3.5. Annual generation for each LCS under minimum capital cost projection

The generation breakdown for the year 2037–2038 under the minimum cost scenario is shown in Fig. 7, and a detailed breakdown of annual generation is presented in Table B.4. As discussed in Section 3.4, it can be seen that offshore wind generation enables a low-cost energy system under high penetrations of solar or high penetrations of onshore wind.

It is interesting to note that the effective CFs achieved by offshore wind in the 15 GW and 22.5 GW minimum cost scenario optimisations are not significantly higher than the CFs onshore wind can achieve, with the CFs reaching a maximum of 37.8 % and 35.5 % respectively (CFs are based only on the electricity which directly services demand). Similar to the average cost scenario, Fig. 7 also indicates that the inclusion of offshore wind tends to decrease the amount of unused surplus generated relative to the control scenario.

4. Conclusions

This paper quantitatively assessed the techno-economic impacts of exogenously fixing offshore wind capacity in a future least-cost NEM under two capital cost projections. It was found that the LCS with the lowest annualised system cost occurred under the minimum capital cost scenario with 15 GW of offshore wind in the NEM. Furthermore, under this minimum cost scenario, the inclusion of offshore wind in the LCS reduced annualised system costs.

In the average capital cost scenario, system costs were found to increase linearly with increasing offshore wind capacity (up to 22.5 GW) due to the higher LCOE of offshore wind compared to other technologies. Cost increases under the average capital cost scenario could be kept below 2.7 % per 7.5 GW increment in the range of 0–22.5 GW of total offshore wind capacity as offshore wind displaced both solar and onshore wind generation sources. Above 22.5 GW of offshore wind capacity, costs increased more significantly as offshore wind was unable to displace sufficient capacity from other technologies. In contrast, under the minimum capital cost scenario offshore wind has a competitive LCOE and can be incorporated into system while reducing annualised system costs.

If offshore wind capital costs fall in-line with the favourable minimum cost projection used in this study, policy makers should seek to encourage the inclusion of offshore wind in their respective energy systems. If the capital cost of offshore wind declines at a slower rate, such that it aligns with the average capital costing used in this study, policies which encourage the uptake of offshore wind should be considered more carefully. This study indicates that under the average cost projections, offshore wind can be included in a future grid to a moderate extent with only minor impacts to the annualised system cost. Organisations managing the transition of electricity systems should also consider potential system cost increases incurred by the inclusion of substantial offshore wind capacity under average capital cost projections against other potential benefits such as: potential for siting closer to load centres, reduced need for transmission infrastructure, lesser use of onshore land resources, and the potential to transition existing fossil fuel workers in offshore oil and gas industries.

Future research in this area could explore the sensitivity of the results to a wider range of capital and operating cost scenarios for offshore wind. Such research would demonstrate the impact differing cost reductions have on the ability of offshore wind to be integrated into a low-cost 100 % renewable NEM.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data Availability

Please refer to relevant references for further information on the NEMO model or the data used in this study.

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Appendix A

See Tables A1-A2.

Table A1
Available Hydropower & PHES assets in NEMO's optimisation.

Project Type	Polygon Number	Capacity (MW)	Storage Limit (MWh)
Hydropower	24	42.5	–
Hydropower	31	43	–
Hydropower	35	71	–
Hydropower	36	2513.9	–
Hydropower	38 a	450	–
Hydropower	38 b	13.8	–
Hydropower	39	586.6	–
Hydropower	40	280	–
Hydropower	41	590.4	–
Hydropower	42	578.5	–
PHES	1	250	2000
PHES	17	500	5000
PHES	24	500	3000
PHES	35	2000	350,000
PHES[a]	36	1740	15,000
PHES	39	700	10,500

[a] Combines NSW PHES: Tumut 3 (6×250 MW), Bendeela (2×80 MW) and Kangaroo Valley (2×40 MW).

Table A2
Battery system capacities used in modelling.

State	Polygon	Battery Capacity [MW]
Queensland	11	300
New South Wales	31	2330
ACT	36	460
Victoria	38b	600
South Australia	27	720

Appendix B

See Tables B1–B4.

Table B1
Optimised capacity breakdown for control and average cost offshore wind scenarios.

	Capacity (GW)					
Fixed Offshore Wind Capacity (GW)	Battery	Solar	Biogas	Wind	PHES	Hydro
0	4.4	31.1	16.8	36.9	5.4	4.8
7.5	4.4	27.3	19	24.6	5.7	4.2
15	4.4	23.5	18	21.3	4.9	5
22.5	4.4	16.8	20.6	9.1	5.4	4.8
30	4.4	14.7	20.1	4.6	5.3	5.1

Table B2
Annual generation breakdown for control and average cost offshore wind scenarios.

	Generation (TWh)							
Fixed Offshore Wind Capacity (GW)	Surplus	Battery	Solar	Biogas	Wind	Offshore Wind	PHES	Hydro
0	48.2	4.7	70.1	7.2	81.3	0	12.5	13.9
7.5	34.6	5.6	66.5	9.9	63.5	18.4	12.2	13.8
15	39.0	4.9	61.3	6.5	56.7	36	11.2	13.2
22.5	19.3	3.9	45.2	9.9	33	71.8	12	13.9
30	29.3	0.6	39.1	8.6	17.8	98	12.9	12.7

Table B3
Optimised capacity breakdown for control and minimum cost offshore wind scenarios.

Fixed Offshore Wind Capacity (GW)	Capacity (GW)					
	Battery	Solar	Biogas	Wind	PHES	Hydro
0	4.4	31.1	16.8	36.9	5.4	4.8
7.5	4.4	28.4	16.4	30.1	5.2	3.9
15	4.4	13.5	18.9	24.3	5.7	5.1
22.5	4.4	27	18.8	8.3	5.4	5.1
30	4.4	16.2	20.1	4.1	5.4	5.2

Table B4
Annual generation breakdown for control and minimum cost offshore wind scenarios.

Fixed Offshore Wind Capacity (GW)	Generation (TWh)							
	Surplus	Battery	Solar	Biogas	Wind	Offshore Wind	PHES	Hydro
0	48.2	4.7	70.1	7.2	81.3	0	12.5	13.9
7.5	48.7	3.9	66.2	7.5	72.7	16.1	11.3	12
15	25.4	0.4	35.7	6.4	83.2	39.9	12.3	11.8
22.5	40.4	5	65.7	7.9	23.8	61.1	12.7	13.5
30	31.3	1	43.7	8.5	15.4	95.6	13	12.6

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