A Portfolio approach to wind and solar deployment in Australia

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Chi Kong Chyong
Carmen Li
David Reiner
Fabien Roques

Most power systems are trying to cope with increasing penetration of Variable Renewable Energy (VRE). We introduce a new method (residual demand minimisation) that can be used to analyse interactions between solar and wind generation in the Mean-Variance Portfolio Theory (MPT) framework. We used this framework to understand the role of electricity transmission in integrating a high VRE share in Australia's largest power system, the National Electricity Market (NEM).

First, we analysed the optimal generation mix for all 16 operational zones in the NEM that maximised the generation output with wind energy only and confirmed the risk hedging benefit of geographical diversification when transmission links are not congested. We then included solar into the portfolio and showed that technological diversification further reduces the risk, especially within each of the transmission operational zone even with relatively low levels of solar penetration.

Since the output maximisation framework might not fully capture some dynamic interactions between wind and solar generation and demand, we considered an alternative objective: minimising the deviation of the generation output from the demand (i.e., residual demand minimisation). In this residual demand minimisation framework, we implicitly also included the cost of backup generation (e.g., OCGT) as well as an estimate of the curtailment cost of wind or solar. We showed that under the new objective, solar became more favourable in the optimisation than when the objective was output maximisation, and therefore the share of solar in the optimal portfolios in NEM increased significantly. Nevertheless, the disadvantage of solar only being able to generate during the day remained and wind still dominated in the optimal solutions. Furthermore, our sensitivity analyses suggest that the way we treat risks in the MPT framework and the way we choose our sample of our time series (e.g., taking only the top 10% of peak load hours vs whole time series) could change the optimal share of solar in optimal generation portfolios.

Our results give rise to a number of policy conclusions. To incentivise investors to integrate their generation portfolio across the NEM, a finer wholesale electricity price signal might be required that could then be used to link with renewable support schemes. For example, instead of the five reference price points currently used in

the NEM, there could be a move to a more granular locational (e.g., nodal) pricing system, at least for generators. Linking revenue streams of a wind (or solar) farm to nodal wholesale electricity market prices would incentivise merchant investors to hedge locational risks and take advantage of the geographical diversification available in the NEM. A move to finer-grained wholesale electricity prices is in line with the current discussion by Australia's Energy Security Board (COAG Energy Council, 2019), which has put forward a series of market reforms including nodal pricing and marginal loss factors applied to individual generators. Other proposed reforms include differentiating between different renewable zones (e.g., greenfield or brownfield) and access regimes to networks (e.g., access via a dedicated asset or through the network) giving a finer-grained approach to coordinated investments in renewables and transmission assets. Even though our 16 regions only provide a crude estimation, our findings about the locational value of existing transmission boundaries, the wind and solar resource base and their correlations for hedging purposes can contribute to the policy discussion around potential market redesign to minimise total system costs for the NEM as it moves towards increasingly higher shares of wind and solar.

Secondly, adopting an integrated investment planning approach where generation and transmission planning are viewed holistically could minimise system cost in the NEM – such an approach could take advantage of our findings that wind generation and transmission capacity expansion are complements (higher wind penetration would always require more transmission so that to minimise the balancing cost of wind, or in the MPT framework, minimise risk at a chosen level of wind output) while solar generation complements wind generation in close proximity (within a transmission boundary or zone). This also means that solar generation competes with transmission capacity expansion at a low level of solar penetration. But overall, with very high wind and solar penetration in NEM, transmission capacity will be needed to minimise system risks associated with wind and solar uncertainties. Thus, while generation investment in the NEM is largely on a merchant basis and transmission investment is regulated, a careful integrated planning process that would minimise risks for generation investment is required – in this regard, our results show that in order to minimise risks of a VRE dominant generation portfolio, transmission capacity and efficient access will become very important. A lack of transmission capacity would therefore imply higher risks and hence higher returns and thus potentially lead to higher energy prices at a high level of VRE penetration.

That said, our proposed research framework did not value exactly how much transmission capacity would be optimal at every level of risk associated with each generation portfolio. Secondly, while our proposed approach looks at wind and solar (and implicitly at backup generation like OCGT and curtailment of VRE), including other emerging technologies like electrical battery storage or even traditional generation technologies like hydro run-of-river, hydro pumped storage, and CCGTs would add value to both policy discussion around optimal transition pathways for Australia's NEM to more renewables. Modelling those technologies explicitly in the MPT approach would alter the efficient frontier and might reward solar generation more than what we currently show in our results (i.e., solar coupled with storage making the technology almost dispatchable and hence lowers its uncertainties). Adding storage might also alter our findings with regard to the extent to which existing transmission capacity is influenced by the wind resource base and its negative correlation with solar. Furthermore, our proposed approach could be applied to other jurisdictions with potentially large VRE potential but also where benefits of geographical diversity could be high (e.g., Europe, North America, China).

Contact	k.chyong@jbs.cam.ac.uk
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