# Impact of High Variable Renewable Generation on Future Market Prices and Generator Revenue

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***Abstract*—This study assesses the potential impact of high renewable generation on the spot electricity prices, generator revenue and profits in an energy-only electricity market. In particular, it presents modelling outcomes for the Australian National Electricity Market (NEM) with a range of possible renewable penetrations in 2030. It is assumed that the current reliability standard is maintained and participants deploy short run marginal cost bidding. The study found that increasing the share of wind and PV generation would likely result in lower average spot prices and subsequently revenue and profit of generators. The revenue impact on large-scale PV was found to be very severe and could lead to insufficient revenue to cover the costs, particularly at higher renewable penetrations. Changes in market mechanisms, such as increasing the Market Price, may be required to ensure revenue sufficiency and long-term resource adequacy in an energy-only market with high renewables.**

***Index Terms*— Revenue sufficiency, energy only market, renewable, Australian National Electricity Market (NEM)**

## I. Introduction

RENEWABLE generation sources, particularly wind and solar photovoltaics (PV), are fast becoming major generation sources in a number of electricity industries. This is due to falling solar and wind energy technology costs and growing concerns over climate change and energy security. Due to the variable availability and somewhat unpredictable nature of wind and PV generation, there are concerns over the potential impacts of such renewable sources on the electricity industry. For restructured electricity industries with competitive market arrangements, the high capital yet low operating costs (short run marginal cost or SRMC) of these technologies poses some interesting additional challenges. In particular, growing penetrations of low SRMC renewable generation in energy-only wholesale markets are likely to reduce spot electricity prices and hence market returns to all generators.

The risk of insufficient revenue to recover both fixed and variable operation costs is one of the major concerns for generators. Concerns over revenue sufficiency are also shared by many policy makers and market regulators given that this might lead to long-term resource adequacy challenges by promoting early retirement and deferred entry to the market, which can reduce the reliability of the electricity supply [1, 2].

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The Australian National Electricity Market (NEM) is a moderately sized market (around 35GW of peak demand and 200TWh per year) with growing wind and solar deployment and significant renewable resource potential, It features a relatively transparent energy-only market with relatively few constraints imposed on generation offers, and therefore provides an interesting case study for analysis of high renewable scenarios, and their revenue implications.

Previous studies have explored the technical feasibility and economics of high renewable scenarios in the NEM, including scenarios of 100% renewable energy [3, 4]. However, these studies have not directly quantified the revenue implications of these high renewable systems. Some observers have raised questions about the feasibility of the NEM's energy-only market design in high renewable scenarios, including claims that a system composed of a majority of low SRMC generation may not deliver appropriate commercial incentives for assured resource adequacy [5].

This study aims to examine the possible impact of high renewable penetrations on spot electricity prices, generator revenues and profits in a future Australian NEM in 2030, with a view to assessing the potential viability of the present energy-only market and its mechanisms to ensure resource adequacy and hence long-term reliability. The paper provides quantitative analysis using a long-term generation portfolio planning and investment modelling tool first developed in [6]. A number of high renewable penetrations are considered including uncertainties associated with these. The modelling assumes that the current NEM reliability standard is maintained and participants deploy SRMC bidding.

## II. Methodology

This study uses a probabilistic generation portfolio modelling tool which extends the commonly applied load duration curve (LDC) based optimal generation mixes by using Monte Carlo simulation to incorporate key uncertainties into the assessment [6]. These uncertainties include future gas costs, carbon policies and electricity demands. The tool determines a probability distribution of annual revenue, operating costs and profits/losses of each generation technology for different possible generation portfolios. The "expected" annual revenue, operating cost and profit of each generation technology for a particular portfolio represent the average of all the simulated revenue, costs and profits from every Monte Carlo run. Generators obtain revenue through a spot market based upon the spot electricity price (or "market clearing price") in each period.

Generators are dispatched based on their SRMC with the objective of minimizing the total system operating cost of meeting demand in a year subject to demand balancing constraints. SRMC is the sum of the fuel, variable operations and maintenance (O&M) and greenhouse emissions costs of each unit. The modelling assumes that generators bid into the market at their SRMCs and the spot price is the cost to supply the last MW of electricity to meet demand.

PV and wind generation is incorporated into the modelling through the use of a residual (net) load duration curve (RLDC) approach to capture the chronology of PV and wind resource variability and its match to NEM electricity demand, based upon historical correlations observed in 2010. As the lowest SRMC generation, PV and wind generation is dispatched first in the merit order. With this approach, hourly simulated PV and wind generation is subtracted from hourly demand over the year to obtain residual demand, which is then rearranged to obtain a RLDC. It is this curve which has to be met by conventional technologies in the portfolio.

A 15% minimum synchronous generation requirement is applied in all dispatch periods to provide adequate system inertia, fault feed-in levels and system stability [7]. This represents the minimum amount to which aggregate conventional generators can be turned down. This constraint is important for high renewable scenarios since some of the most promising kinds of renewable generation (notably wind and PV) are non-synchronous and therefore do not generally provide inertia and fault feed-in current to the system [1]. For the purposes of this study, coal, gas and hydro plants are assumed to provide synchronous generation (some types of renewable generation such as solar thermal, geothermal and biomass are also synchronous, although these technology types have not been modelled in this study).

In addition to the market revenue, conventional generators also receive a supplementary payment in periods in which they are dispatched out of merit order to satisfy the 15% synchronous requirement constraint. This supplementary payment is referred to in this study as a "constrained on payment", and is determined based upon the SRMC of the most expensive conventional generator that is dispatched to meet the synchronous requirement.

For each Monte Carlo run, annual revenue, of each generation technology is calculated according to Eq. (1) – (3).

*Spot market revenue*
$$REVSpot_n = \sum_{t=1}^{T} P_{n,t} \times MC_t \quad (1)$$

*Constrained on payment*
$$CP_n = \sum_{t=1}^{T} Pconv_{n,t} \times SRMC\,max_t \quad (2)$$

*Annual revenue*
$$REVTotal_n = REVSpot_n + CP_n \quad (3)$$

where $P_{n,t}$ is the generation output of technology $n$ (MW), $MC_t$ is the market clearing price ($/MWh), $Pconv_{n,t}$ is the output of conventional generator (MW) that is dispatched out of merit order to meet the synchronous requirement, $SRMCmax_t$ is the SRMC of the most expensive generator ($/MWh) that is dispatched to meet the synchronous requirement in period $t$.

Annual operating cost and profit of the generator are determined based upon Eq. (4) – (5) respectively.

$$OPEX_n = \sum_{t=1}^{T} P_{n,t} \times SRMC_{n,t} \quad (4)$$

$$OPProfit_n = REVTotal_n - OPEX_n - FOM_n \quad (5)$$

where $SRMC_{n,t}$ is the SRMC ($/MWh) of technology $n$ in period $t$ and $FOM_n$ is the annual fixed operating and maintenance (O&M) costs ($) of technology $n$.

## III. The Australian National Electricity Market (NEM) Case Study

Six different renewable penetration scenarios for the NEM in 2030 were considered: 15%, 30%, 40%, 60%, 75% and 85% (by energy contribution). Eight technologies were included: coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), co-generation, distillate, utility-scale PV (single axis tracking), wind (on shore) and hydro. The renewable penetration scenarios and the percentage of each renewable technology are summarised in TABLE I. Note that the proportion of PV and wind energy for each renewable penetration were selected based on assumptions on future investment scenarios, as explained in [8].

TABLE I
Different Renewable Penetration Scenarios

| Renewable penetration scenarios | Achieved total renewable penetration | % PV energy | % Wind energy | % Hydro energy | % Fossil energy |
|---|---|---|---|---|---|
| 15% | 14 | 4 | 4 | 6 | 86 |
| 30% | 27 | 7 | 14 | 6 | 73 |
| 40% | 40 | 10 | 24 | 6 | 60 |
| 60% | 60 | 20 | 34 | 6 | 40 |
| 75% | 73 | 30 | 37 | 6 | 27 |
| 85% | 83 | 39 | 35 | 9 | 17 |

The maximum spot price is set at $13,500/MWh, which is the current Market Price Cap (MPC) for the NEM [9]. This price is triggered in periods when demand exceeds available generation capacity. The installed capacity was determined so that each generation portfolio will, on average, meet the present NEM reliability standard of 0.002% annual unserved energy (USE).

### A. Hourly Demand and Generation

An hourly electricity demand profile for 2029-2030 was obtained from analysis by the Australian Energy Market Operator (AEMO) on a 100% renewables system under a moderate economic growth scenario. Hourly wind and solar output profiles for 2030 were simulated from hourly traces of 1-MW on-shore wind and solar PV (single axis tracking) generation in different locations across the NEM provided by AEMO [7]. For hydro generation an annual hydro energy dispatch limit of 13 TWh was applied, based upon the long-term average hydro generation estimated by AEMO [7].

Generation output of each thermal technology (coal, CCGT, OCGT, cogen and distillate) in each period was determined using merit order dispatch based upon their SRMCs in 2030. Technical and cost parameters of generating plants were based upon a previous study presented in [8].

### *B. Modelling Uncertainties*

Key uncertain parameters considered in the modelling are gas prices, carbon prices and electricity demand as they have experienced a higher degree of uncertainty than other variables [10, 11]. Lognormal distributions were applied to model future fuel and carbon prices to reflect the asymmetric downside risk associated with high price outcomes. Demand uncertainty was modelled assuming a normal distribution of residual peak demand for each renewable penetration scenario. Both lognormal and normal distributions can be characterized by their mean (expected value) and standard deviation (SD).

The mean and SD of fuel prices and carbon prices were determined based upon Australian Government estimates for 2030 [12, 13]. Correlated samples of coal, gas and carbon prices were simulated from their marginal lognormal distributions 10,000 times using Multivariate Monte Carlo simulation techniques described in [6]. The mean and SD of peak demand were estimated based on the Probability of Exceedance (POE) demand projections in 2029-2030 provided in [7], and were explained in detail in [8]. Residual peak demand were also simulated 10,000 times. In order to achieve the 0.002% USE reliability standard on average, there were instances where the simulated residual peak demands exceeded the installed fossil-fuel generation capacity.

## IV. Modelling Results And Analysis

With Monte Carlo simulation techniques, the modelling calculated overall generation costs, emissions, revenue and operating profits for each technology within each possible generation portfolio for 10,000 simulated future fuel prices, carbon prices and electricity demands. The cost of USE is valued at the MPC ($13,500/MWh), and is included in the overall generation cost.

Fig. 1 illustrates the efficient frontiers consisting of optimal generation portfolios in terms of expected generation cost and cost risk (SD of cost) for different generating portfolios, ranging from 15% to 85% renewable generation. Each dot is a plot of a portfolio's expected costs (against the vertical axis) and the cost risk (against the horizontal axis), calculated over 10,000 simulations.[1] As illustrated in Fig. 1, the lowest cost generation portfolio features 60% renewable energy, with an expected cost of $92/MWh. The costs rise as renewable energy increases to 75% and 85%, and are also higher for the renewable penetration levels below 60%.

For the purpose of this discussion, only the revenue and profits of each technology in the least cost portfolio for different renewable penetrations are quoted. For example, the least cost portfolio for the 15% renewable portfolio is the one that consists of 41% coal, 21% CCGT, 7% OCGT, and this lowest cost portfolio is used as the basis for analysis.

The average spot price duration curve for the least cost portfolio in each renewable penetration for the highest 2% price periods is shown in Fig. 2. The figure also shows the corresponding PV and wind generation outputs in those periods. The results suggest that the magnitude of price spikes increases with higher renewable penetrations but the high price periods (e.g. greater than $500/MWh) are less frequent. For example, the average highest spot price in the 85% renewables scenario is around $8,500/MWh compared to $1,500/MWh in the 15% renewables scenario. However the number of periods where the spot prices are greater than $500/MWh is less than 0.4% of the time (35 hours per year) in the 85% renewables scenario compared to 2% of the time (75 hours per year) in the 15% renewables scenario.[2]

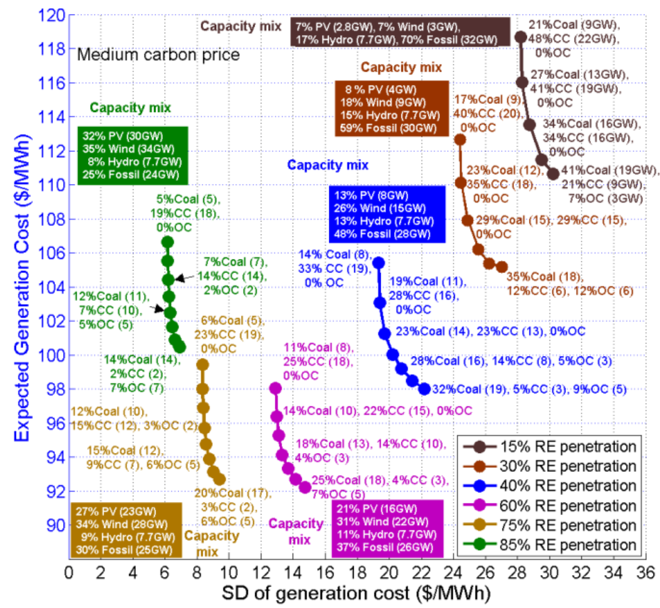



Fig. 1. Efficient frontiers containing optimal generation portfolios for different renewable penetrations in 2030. The capacity of fossil-fuel technologies in each portfolio is shown in GW (in brackets) and percentage share. The coloured boxes show the share of each technology by capacity installed.

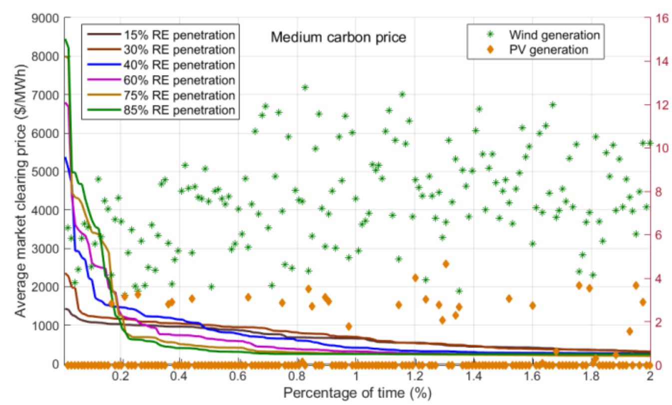



Fig. 2. Average market price duration curve for the top 2% of the price periods and the corresponding PV and wind generation.

Since the model does not incorporate strategic bidding behaviour, high spot prices in the model are driven by periods where unserved energy is occurring. This means that the price duration curves illustrate that there are fewer periods of supply and demand imbalance as the renewable penetration increases. However, the magnitude of USE occurring in each of those periods is higher (USE is concentrated into fewer periods as

[1] For each renewable penetration, the amount of distillate, cogeneration, hydro, PV and wind capacity was fixed for every possible thermal portfolio.

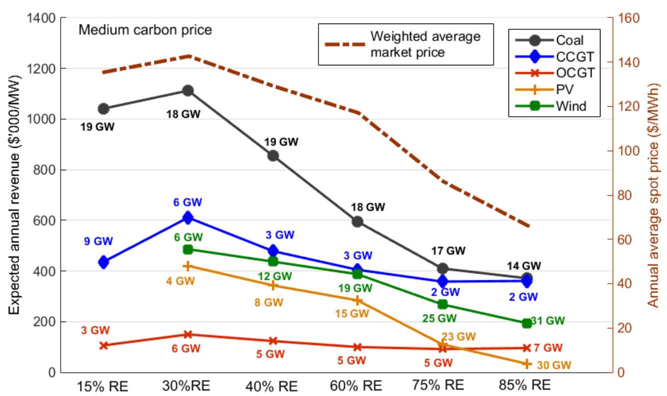
[2] Note that the figure shows the 'average' spot price across 10,000 simulated fuel prices, carbon price and electricity demand for each period. Without modelling the uncertainties, the highest spot price shown on the graph would be $13,500/MWh.

the renewable percentage increases, keeping in mind that the total USE for each generation portfolio is the same).

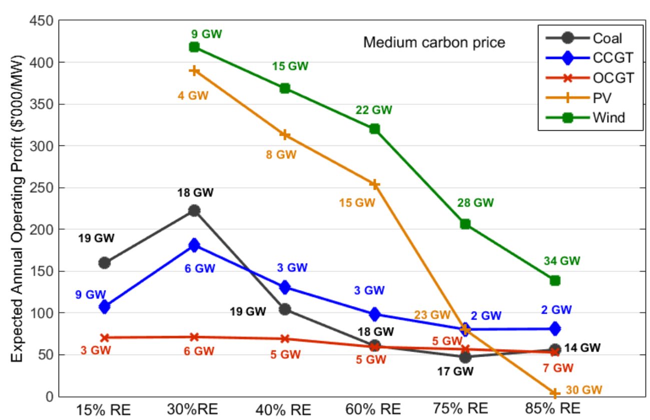
Fig. 3 shows the expected annual generator revenue and operating profit of each technology in the least cost portfolio for each renewable penetration. The annual average spot prices are also shown in Fig. 3(a). The impact of the carbon price on the revenue, operating costs and hence profits of the fossil fuel plants are apparent.

Although the revenues of PV and wind plants are relatively low, their operating profits of PV and wind plants are significantly higher than those of coal and CCGT, particularly at low to moderate renewable penetrations (i.e. from 15% to 60% renewable penetration). This is due the low operating cost of renewable generation and the impact of carbon price on the high operating costs of fossil fuel plants.

The operating profit of each technology generally reduces as the amount of renewables increases due to lower annual average spot prices influenced by the low SRMCs of wind and PV. However, fossil fuel generators are able to make operating profit even at high renewable penetration. This is likely influenced by the 15% minimum synchronous generation requirement applied in the modelling, which enforced thermal generating plants (most likely coal) to supply at least 15% of demand in every period. Hence they are able to earn revenue to most periods. This is particularly crucial during scarcity or near scarcity periods when the spot prices are extremely high.




(a)




(b)

Fig. 3. (a) Expected annual revenue of each technology and annual average spot prices (b) Expected annual operating profit of each technology for each renewable penetration. The capacity (MW) of each technology is also shown.

On the other hand, the profits of PV and wind reduce far more significantly than for thermal generation technologies. This is particularly the case for PV as shown by its negligible operating profit at an 85% renewable penetration even without taking into account annual capital repayments. Since PV, and to a lesser extent wind, do not often generate during high price periods (as shown in Fig. 2), they were unable to benefit from the high spot prices. This result may due to the very large proportion of PV included in the 75% and 85% renewable portfolios, which may be higher that economically optimal, resulting in high costs and almost negligible profits. These issues warrant further investigation

The modelling results suggest that, at high renewable penetration levels and given the current market arrangements, PV and wind plants might not earn sufficient revenue to cover their costs. In contrast, coal and CCGT plant appear to maintain operating profitability following an initial decline. OCGT plant appear to maintain operating profitability regardless of the renewable penetration level, suggesting that peaking plant may be relatively immune to the reducing average wholesale price, and able to flexibly adjust as required to access high priced periods. One of the options for increasing generator revenue is to increase the MPC from the current $13,500/MWh, since a higher MPC will lead to more revenue earned during high demand periods and hence higher profits for generators [14]. This will be examined in future work.

## V. Conclusions

This paper assesses the impact of variable renewable generation on spot market prices and generator revenues in an energy-only electricity market. The Australian National Electricity Market (NEM) with different renewable penetrations in 2030 under uncertain gas prices, carbon pricing policy and electricity demand was used as a case study.

Modelling results indicate that the annual average spot price generally reduces as the amount of renewable generation increases due to the low operating costs of wind and PV generation. Although there were fewer periods of demand and supply imbalance as the renewable penetration increases, the magnitude of the imbalance and hence average price spikes were greater. Generally, the reduction in the average spot price results in reduced revenues and profitability of generators and potentially leads to insufficient revenue to meet costs, particularly for large scale wind and PV generators.

The revenue impacts on PV and wind generation are very severe at the high renewable penetrations considered. Therefore, changes in market mechanisms such as increasing market price cap may be required to ensure revenue sufficiency and long-term resource adequacy in an energy-only market with high renewables. Further work is warranted to explore these issues.

There are some limitations in this study. The findings are highly dependent on modelling and input assumptions. For the renewable penetration greater than 60%, the proportion of PV and wind generation chosen in the modelling may not be the most economically optimal, resulting in higher industry costs and almost negligible operating profits for PV. Furthermore, there may be mechanisms other than imposing a minimum synchronous generation constraint, which is a costly option, to provide system inertia and frequency response at times of high non-synchronous renewable penetrations. These limitations represent areas for future work.

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