2015 ASIA-PACIFIC SOLAR RESEARCH CONFERENCE

Peer Reviewed
2015 Solar Research Conference

Oscar Wilkie

Revenue Sufficiency in the Australian National Electricity Market with High Penetrations of Renewable Energy

Oscar Wilkie[1], Iain MacGill[2], Anna Bruce[1]
[1]*School of Photovoltaic and Renewable Energy Engineering, UNSW, Sydney, Australia*

[2]*Centre for Energy and Environmental Markets and School of Electrical Engineering and Telecommunications, UNSW, Sydney, Australia*

E-mail: o.wilkie@unsw.edu.au

Abstract

Given the declining costs of renewable energy technologies and the need to drastically reduce greenhouse gas emissions from the electricity sector, it seems likely that electricity industries around the world will have to successfully integrate very high penetrations of renewable generation. However, there is the question of how well existing wholesale electricity market arrangements might facilitate the investment necessary to achieve high renewable penetrations. In particular, the low operating costs of variable renewables such as wind and solar PV places downwards pressure on spot market prices. The likelihood of significantly higher penetrations of renewables raises the question of whether the Australian National Electricity Market (NEM)'s present wholesale spot market is capable of providing sufficient revenue to generators to allow them to recover their long run marginal costs and hence appropriately incentivise entry of new renewable generation, as well as potentially other new generation required to ensure reliable industry operation.

This paper seeks to answer this question by modelling the revenue sufficiency of generators in a scenario with a high penetration of renewable energy in the NEM. This is done using PLEXOS, a commercially available electricity market simulation software package. The model used is adapted from the Australian Energy Market Operator's PLEXOS database used in the 2014 National Transmission Development Plan. The impact of different levels of strategic bidding on prices and revenue was studied using PLEXOS's Nash-Cournot competition model.

Modelling results suggest that for long-run profitability, new entrant generators may need to rely on significant levels of strategic behaviour, reductions in generator capital costs, policy intervention, or changes to the present NEM wholesale market design.

1. Introduction

Serious action by Australia to prevent anthropogenic climate change must involve significant reduction in electricity industry carbon emissions, most likely through an increase in the penetration of renewable generators. Technical modelling from numerous sources suggests that a 100% renewable generation mix is technically and economically feasible in the Australian National Electricity Market (NEM) (Elliston et al., 2013; Vithayasrichareon and MacGill, 2012; Wright and Hearps, 2010; AEMO, 2013a). However, while existing studies have assessed the industry cost of transitioning to high penetrations of renewable generation, they have not assessed commercial market outcomes for participants, which are determinants of investment in a restructured electricity industry.

Variable renewables such as solar PV and wind have low short run marginal costs (SRMC) in comparison to conventional thermal generation technologies (BREE, 2012). At current penetrations of renewables this places downward pressure on spot market prices, a well documented effect (Cutler et al., 2011; AEMO, 2013b; ACIL Allen, 2014b). This has raised concerns that under future high penetration renewable energy scenarios, the current NEM wholesale market design may not result in sufficient generator revenues to allow for capital cost recovery and thus incentivise the entry of new generators.

The majority of work to date has focused on technical feasibility and total industry costs rather than market outcomes such generator profitability. Preliminary work by Reisz and MacGill assessed whether changes to the market price cap would enable revenue recovery in an electricity market with 100% renewables penetration (Riesz and MacGill, 2013), although this work used approximations of expected prices, and did not involve simulation of market dispatch of a high renewables generation mix. Work has been done to model the impact of increasing renewables penetrations on spot prices and generator operating profits (Vithayasrichareon et al., 2015). However, this model did not consider the impact of annual capital cost repayments on profitability. Additionally, all generators in this model bid in at their short run marginal cost (SRMC) whereas in practice strategic bidding from generators is a key driver of high price events.

This paper seeks to explore the issue of generator long-run profitability using PLEXOS to model market dispatch of an 80% renewables generation mix. PLEXOS has previously been used to model the performance of different generation mixes with a focus on the impact of technical operating constraints on overall industry costs, as well as market returns for different types of generators (Lozanov, 2014). This work seeks to move towards a more realistic model of the NEM by (i) assessing revenue sufficiency for individual generators and companies rather than technology classes as a whole, (ii) increasing the period of analysis from one year to six, (iii) modelling generator outages, and (iv) making a preliminary assessment of the impact of strategic bidding strategies using a Nash-Cournot game.

Section 2 outlines the methodology used to create the basic PLEXOS model. The results of this modelling are presented in section 3. The impact of strategic bidding is explored in section 4. A discussion of the results is contained in section 5 and conclusions are presented in section 6.

2. Methodology – Development of the basic model

Hourly dispatch of an 80% renewables portfolio in the NEM was simulated using aggregated historical demand data (AEMO, 2015b) and corresponding hourly wind and PV generation data (ROAM Consulting, 2012) from financial years 2006 to 2011 using PLEXOS, a commercially available electricity market simulation software package. This model was developed using the 2014 National Transmission Development Plan (NTNDP) PLEXOS database (AEMO, 2015a), which contains the key generator characteristics. Simulations have been completed over a period of six years in order to capture inter-annual variability in demand and renewable generation.

The wind and PV generation data is sourced from hourly profiles of representative 1MW generation traces developed for 43 locational polygons covering the five NEM regions for 8 to 9 reference years. These were produced by selecting all sites within each polygon available for the relevant technology, estimating build limits for each site and applying a relevant energy conversion model to weather data.

In the NTNDP the NEM is modelled as a single node for each NEM region with a constrained interconnector between the nodes. However, in order to avoid making assumptions about future interconnector capacities or the location of new generation, the NEM was treated as a 'copper plate' system in this paper, with no transmission constraints or losses between regions.

2.1. Generation portfolio

The generation portfolio used in the high penetration renewables scenario for this study was obtained using the National Electricity Market Optimiser (NEMO) (Elliston et al., 2014) with a target of 80% renewables. NEMO is an open source[1] optimiser, which utilises a genetic algorithm to search for least-cost generating systems for a given penetration of renewable energy. The following inputs were used to run NEMO with a target of 0.002% unserved energy for 2010 demand data:

- $8/GJ gas prices.
- Capital cost estimates for 2030 from the Australian Energy Technology Assessment (AETA) (BREE, 2012). A discount rate of 10% was used as per the AETA.
- No generation from concentrated solar thermal generators, due to the complexity of modelling these generators and minimal installed capacity of this technology in the least-cost mix output by NEMO (due to high capital costs in the AETA model).
- Historical wind generation data was sourced from the AEMO 100% Renewables Study (ROAM Consulting, 2012) polygons 1, 20, 24, 38b and 42. Historical Single Axis Tracking (SAT) PV data was sourced from Polygons 14, 21, 13 and 37.

The resultant generation portfolio and dispatch results from NEMO, which were implemented in the PLEXOS model, are shown in Table 1.

Table 1. 80% Renewables Portfolio generated by the NEMO (Elliston et al., 2014)

Technology	*Capacity [GW]*	*Capacity Share*	*Energy Generated [TWh]*	*Energy Share*	*Capacity Factor*
Pumped Storage Hydro	2.2	3.1%	6.9	3.4%	35.7%
Biogas Turbine	6.1	8.7%	4.8	2.4%	9.0%
OCGT	7	10.0%	0.6	0.3%	1.1%
SAT PV	5.5	7.9%	16.1	7.9%	33.4%
Wind	39.7	56.8%	123.7	60.5%	35.6%
Coal	4.3	6.2%	37.8	18.5%	100.0%
CCGT	0.3	0.4%	2.4	1.2%	89.8%
Hydro	4.8	6.9%	12	5.9%	28.5%
Surplus	N/A	N/A	30.4	15.0%	N/A

Black coal, OCGT and CCGT generation was modelled in PLEXOS using the following existing units from the NTNDP database: Bayswater 1 & 2, Eraring 1, Liddell 1 & 2, Vales Point B unit 5, Mount Piper 1, Colongra 1 to 4, Uranquinty 1 to 4, Tallawarra 1. Hydro and pumped storage hydro generators were modelling using all existing hydro generators in the

[1] Source code is available at http://nemo.ozlabs.org/

NTNDP database. Additional new build OCGT was modelled for the remaining capacity using units of the new build NCEN OCGT generator in the NTNDP database.

Biofuel gas turbines were modelled using the new build NCEN OCGT generator characteristics with a \$92/MWh short-run marginal cost, the same technique applied to modelling biofuel used by Elliston et al. (2013) and used to create the generation mix with NEMO.

Renewable generators were modelled in PLEXOS using the ROAM Generation Profiles and generator characteristics from the Australian Energy Technology Assessment (BREE, 2012). However, rather than using only the siting wind generation in the polygons used as inputs to NEMO, known as portfolio A, the generation in each state was split into two polygons, known as portfolio B. This was done in order to increase diversity in the generation profiles so more accurately reflect the diversity that would be present in the NEM should renewable penetrations reach the high levels being modelled. One third of the generation capacity for each polygon resulting from the original run was transferred to a new polygon in the same state. To do this, PV generation was reallocated to polygons 6, 31, 32 and 38a, and wind generation was reallocated to 17, 31, 32, 37 and 42. Implementing generation portfolio B reduced the NEM average price between 2006 and 2011 from \$43.43/MWh to \$43.07/MWh and reduced peak unserved energy in a single year from 0.0007% to 0.0002% of total demand. As the NTNDP PLEXOS model also includes demand side participation whereas NEMO does not, it should be noted that the maximum of unserved energy plus demand curtailed in a single year decreased from 0.0015% to 0.0008% of demand.

2.2. PLEXOS and the NTNDP Model

The 2014 NTNDP PLEXOS dataset is configured for running long term planning simulations with a horizon of 25 years using the Long Term (LT) Plan simulation phase (AEMO, 2015a). To model hourly dispatch a number of modifications need to be made, in particular removing the LT Plan simulation phase and adding a Short Term (ST) Schedule phase and a Medium Term (MT) Schedule phase.

ST Schedule is used to solve hourly dispatch and deals with unit commitment and any constraints included in the model. The ST schedule phase was set to solve dispatch in weekly step sizes, reducing simulation time compared to longer step sizes but still enabling reasonable arbitrage opportunities for pumped storage hydro generators whose operational decisions optimised in ST Schedule rather than MT Schedule (Energy Exemplar, 2013a).

MT Schedule solves medium term constraints, such as the allocation of hydro generation, which are computationally intractable at the ST Schedule resolution. It does this by reducing the number of simulation intervals to a reduced chronology. For this model the ‘fitted chronology’ method was chosen such that the weekly load curve was decomposed into 35 load blocks per week using the least-squares method. Additionally, the MT Schedule phase allows modelling of competitive behaviour.

2.3. Modifications to the NTNDP Model

A number of changes were made to the 2014 NTNDP PLEXOS model to include key parameters related to unit commitment and generator outages.

A minimum synchronous generation constraint of 10% of total generation was included to ensure some level of system inertia. Synchronous generation was sourced from coal, CCGT, OCGT, hydro and biofuel generators. Generator start profiles, minimum up and minimum downtimes were added for coal and gas generators to ensure unit commitment was modelled more realistically. Data was sourced from ACIL Allen's Fuel and Technology Cost Review completed for the 2014 NTNDP (ACIL Allen, 2014a).

Maintenance rates, equivalent full forced outage rates and time to repair were sourced from ACIL Allen (2014a). Time to repair was modelled as constant to reduce computation time. Maintenance and forced outages were confined to single units rather than the entire plant, which may occur due to substation outages or network constraints. Additionally, partial unit outages were not considered. Wind & PV generators were modelled as 1MW units.

PLEXOS automatically schedules maintenance events for all generators prior to the ST Schedule and MT Schedule simulation phases. Forced outage patterns are generated in PLEXOS for each generator using a Monte Carlo method. The 'Convergent Monte Carlo' stochastic method was used, which pre-filters outage patterns by choosing the pattern closest to the expected outcome based on the chi-squared statistic of five candidate patterns (Energy Exemplar, 2013b).

Modelling was completed using a Monte Carlo run with 20 distinct outage patterns to assess the impact of outages. Additionally, a fixed random number seed in PLEXOS was used to create a single outage pattern for use in modelling competitive behaviour. This was done to minimise computation time for these runs.

3. Modelling Results

The modelling results of the base model for six simulated demand years without any consideration of generator market power are presented below. The results show significant variability in pricing between demand years, dependent on the particular balance of supply and demand in that year. Low spot market profits in relation to annualised capital costs are apparent. The NEM Load Weighted Average Price (LWA) in the period of analysis has a mean of $66/MWh for the 20 pattern Monte Carlo run. This is compared to the average price of $43/MWh before the modifications discussed in section 2.3 were introduced.

As shown below in Figure 1, there is significant variation in the annual average price depending on the year and the outage pattern. In some years, such as 2006, the range from minimum to maximum price in the Monte Carlo run was quite small. However in other years the outage pattern causes major variability in price, such as in demand year 2011 where the range was $20.29/MWh. Figure 1 also shows that the single outage pattern chosen for the modelling of competitive behaviour, discussed in section 4. Figure 1 appears to show prices increase from 2006 to 2011, however this is a feature of how supply matched with demand in each particular year rather than a trend of increasing prices. The simulation was run over a period of six years to capture the variability in demand and renewable generation rather than to assess a trend of increasing prices.

The mean annual unserved energy from the Monte Carlo run ranged from 0.0000% to 0.0019%. The maximum value for a single year was 0.0031%. The peak value of unserved energy for the single outage trace run was 0.0029%, in all other years the unserved energy was below the 0.002% reliability standard.

At the pricing levels resulting from the single outage trace, the majority of technology types will struggle to recover their long run costs from spot market revenues alone, as shown in Figure 2. In this scenario no wind or solar PV generators made a profit in the long run.

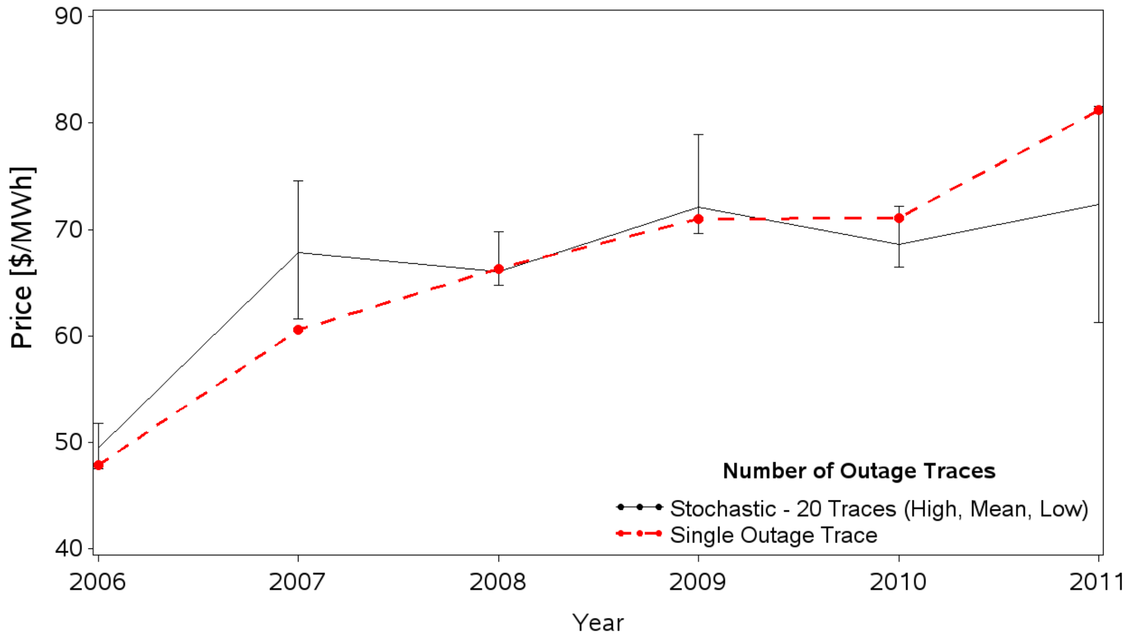

Figure 1. NEM pricing for simulated operation of 80% RE in the NEM over the demand years 2006 to 2011. Mean, minimum and maximum values from a convergent Monte Carlo run alongside results from a single trace.

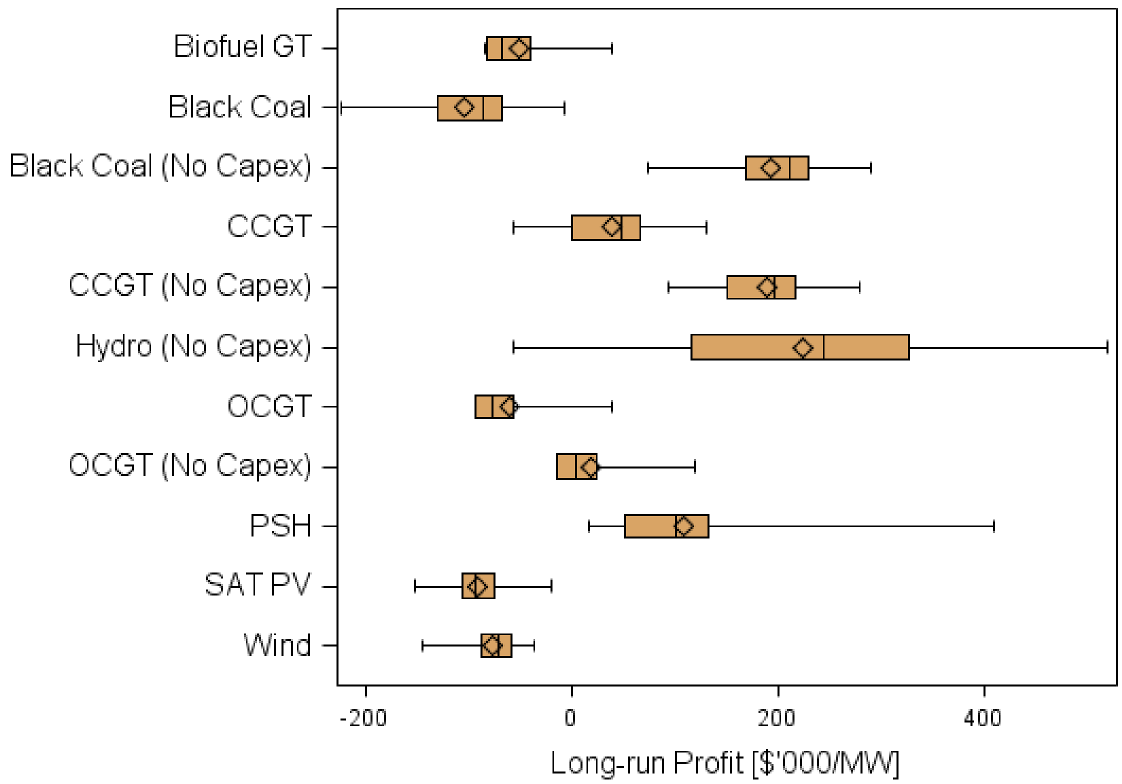

Figure 2. Box plots of generator long run profitability by technology type annually, single outage trace. Whiskers show full range of observations.

4. Modelling Strategic Bidding in the NEM

Strategic bidding behaviour by generators can have a significant impact on spot market prices. The Australian Energy Market Commission (AEMC) observes that generators do not currently exert market power for extended periods of time and so do not exert 'substantial market power' (AEMC, 2013). However, market power has been noted as a factor in high market price events in the NEM (Biggar, 2011).

4.1. Implementation

Strategic bidding behaviour from generators was modelled by assigning generators to company groups that participate in a Nash-Cournot game. PLEXOS solves the Nash-Cournot game in the MT Schedule phase, and thereby creates bidding strategies for use in the ST Schedule model (Energy Exemplar, 2015). In the Nash-Cournot game each company adjusts their bids to find an equilibrium against a demand function on the basis that other companies keep their bids the same. The amount of generation participating in the Nash-Cournot game is determined by each company's level of strategic bidding, which can be specified in the PLEXOS model. Pricing and profitability was explored for the three different sets of companies described in Table 2.

Table 2. Description of generation ownership sets used to model competitive behaviour

Set	Description
A	6 companies. Each company owns all the generation of a particular technology type, with a single company owning all the OCGT and CCGT.
B	5 diversified companies. Each company owns a variety of generation technologies. Two companies own 30% of capacity each, one company owns 20% of capacity, and two companies own 10% of capacity each
C	10 diversified companies. Each company owns a variety of generation technologies. Three companies own 15% of capacity each, four companies own 10% of capacity, and three companies own 5% of capacity each

4.2. Results

Strategic bidding behaviour can result in significant uplift in system prices, as shown in Figure 3. The prices resulting from Company Set B are systematically higher than that of Sets A and C. Thus it can be inferred that fewer participants lead to greater market power for those companies and that diversified companies hold more market power than those owning a narrow range of technologies. However, counter intuitive results occur at 5% strategic bidding, as the price is higher for company set C than for set B. This is counter intuitive as, in theory, the greater the number of market participants, the less market power each participant may exert. This is likely due to the perverse effects that the Nash-Cournot competition model produces at low levels of strategic bidding when the model appears to break down. For example, for company set B at levels of 1% strategic bidding the average price is -107$/MWh, an obviously unrealistic result which arises because the Nash-Cournot model solves for an equilibrium against a demand function and price is not constrained to be positive.

For company set C with 10% of generation bidding strategically there were some instances of revenue sufficiency in every technology type, as shown in Figure 4. In this case the majority of wind generators were profitable however the majority of PV generators were not.

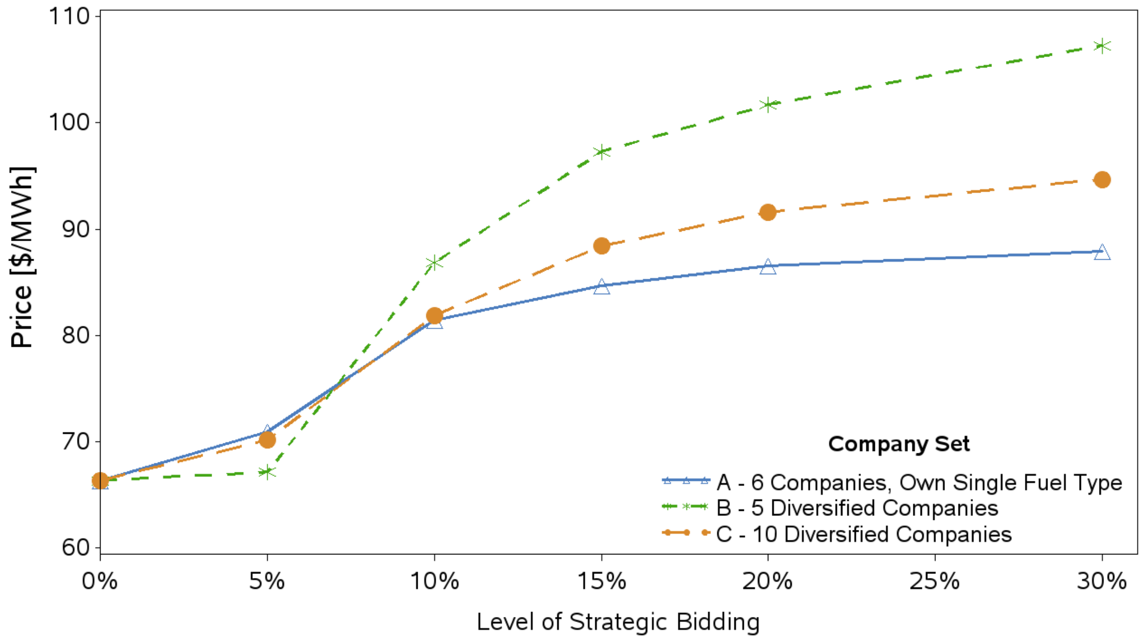

Figure 3. Load weighted average price at varying levels of market competition

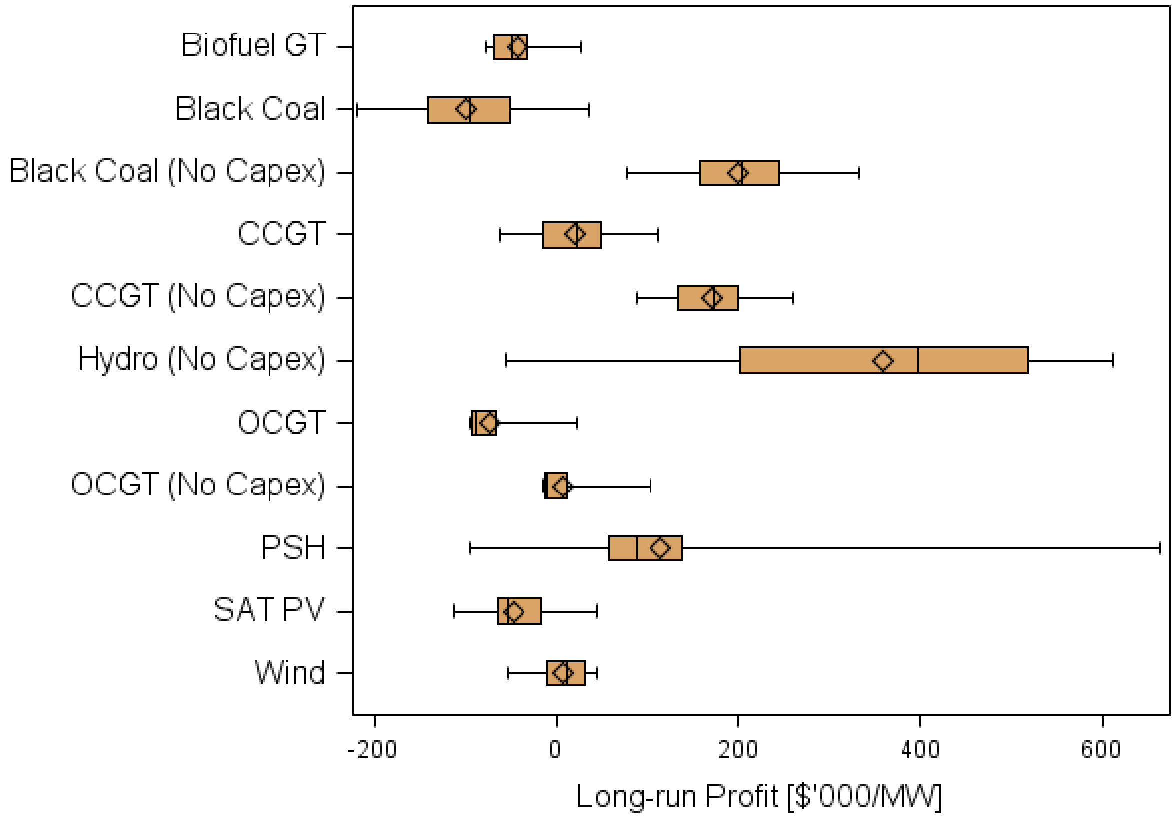

Figure 4. Box plots of generator long run profitability by technology type annually, single outage trace with 10% strategic bidding for company set C.

5. Discussion

Caution is required when considering the results of this study given the complexities and challenges associated with market simulation in PLEXOS, the assumptions involved in implementing an 80% renewables scenario, and with the exercise of market power in particular. Still, the modelling outcomes suggest that high renewable penetrations in the NEM may lead to many generators being unable to pay off their capital costs without significant levels of market power being exerted. It is particularly notable that the new build renewable generators may not have sufficient incentive from spot market revenues alone to enter the market. Existing generators, such as black coal and hydro, represent sunk capital costs and thus may be profitable on the basis of their spot market revenues. However, the owners of these generators may still have debt payments so some capital costs (CAPEX) will likely need to be considered. Since generator capital costs are key variable in the revenue sufficiency equation, further reductions in capital costs could enable spot markets to provide sufficient revenue to new generators.

These findings should also be considered in the light of failure to achieve the NEM reliability standard in some years. This implies that there is not a significant oversupply of capacity in the market placing downward pressure on prices. This unserved energy likely arose because outages were not modelled in NEMO when creating the input generation portfolio. As the generation mix was chosen by NEMO to meet the 0.002% reliability standard specifically it is expected that when supply is withdrawn due to outages the reliability minimum standard will be exceeded. Furthermore, the breach of reliability standard occurred in the simulated year of 2011, whereas NEMO was run for 2010 only. In future work, incorporating outages and other constraints into the model used to create the input generation mix might ensure the reliability standard was not breached, however prices would decrease compared to the current generation portfolio. Running NEMO over a longer timeframe or using a method such as PLEXOS's LT Plan could ensure the generation mix is better matched to the dispatch constraints and load profiles.

A key limitation of this work is that transmission constraints between regions were not considered. Future modelling to should aim to address this, as these constraints are a key driver of market prices and increase the impact of market power (Biggar, 2011). Additionally, the modelling could be improved by using more polygons per state for each technology type to better reflect renewable generator diversity.

The issue of revenue sufficiency can be addressed in a number of ways. This could include increasing the market ceiling price, as suggested by Riesz and MacGill (2013), which would increase generator revenue during periods of unserved energy and allow for greater strategic bidding. Higher levels of demand side participation would ensure that the value of energy to consumers is better valued and would result in less generation capacity being needed to meet the reliability target. However, the impact that this would have on prices in the long run is unclear.

Alternatively, a transition to a capacity market, the introduction of carbon pricing, or a side payment scheme for renewable generators, such as that currently implemented with the Large-scale Renewable Energy Target, may ensure revenue adequacy. Modelling the impact of carbon pricing using the model developed in this paper is a key area for further work.

6. Conclusion

This research modelled spot market dispatch of an 80% renewables portfolio in the National Electricity Market to investigate questions regarding the revenue sufficiency of different generation technologies under the current NEM design. Significant uplift in spot prices was seen by incorporating the impact of generator operating constraints and generator outages. However, these prices were not sufficient for solar PV and wind generators to recover their capital costs through spot market revenues alone. This was the case even though the NEM reliability standard was breached in some years of the simulation, indicating that there was not an oversupply of generation capacity. The model was extended to include the impact of generator market power, showing that generators may recover their long run costs with sufficient strategic behaviour. Changes in market design, significant reductions in capital costs, or policy intervention may be required for long run cost recovery, and to incentivise investment in new generation.

7. References

ACIL Allen 2014a. Fuel and Technology Cost Review - Data. ACIL Allen.

ACIL Allen 2014b. RET Review Modelling. ACIL Allen.

AEMC 2013. Final Rule Determination - Potential Generator Market Power in the NEM. Australian Energy Market Commission.

AEMO. 2013a. *100 per cent renewable study - modelling outcomes | Department of the Environment* [Online]. Australian Energy Market Operator,. Available: http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes 2015].

AEMO 2013b. South Australian Wind Study Report 2013. Australian Energy Market Operator.

AEMO. 2015a. *2014 Plexos LT model and traces* [Online]. Australian Energy Market Operator. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/2014%20NTNDP%20LT%20Database%20and%20Traces.ashx [Accessed 30/04/2015 2015].

AEMO 2015b. NEM Market Management System (MMS). Australian Energy Market Operator.

Biggar, D. 2011. The Theory and Practice of the Exercise of Market Power in the Australian NEM. Australian Energy Regulator.

BREE 2012. The Australian Energy Technology Assessment (AETA) 2012 Report. Bureau of Resources and Energy Economics.

Cutler, N. J., Boerema, N. D., MacGill, I. F. & Outhred, H. R. 2011. High penetration wind generation impacts on spot prices in the Australian national electricity market. *Energy Policy*, 39**,** 5939-5949.

Elliston, B., MacGill, I. & Diesendorf, M. 2013. Least cost 100% renewable electricity scenarios in the Australian National Electricity Market. *Energy Policy,* 59**,** 270-282.

Elliston, B., MacGill, I. & Diesendorf, M. 2014. Comparing least cost scenarios for 100% renewable electricity with low emission fossil fuel scenarios in the Australian National Electricity Market. *Renewable Energy,* 66**,** 196-204.

Energy Exemplar. 2013a. *PLEXOS Wiki - Pumped Storage* [Online]. Energy Exemplar. Available: http://wiki.energyexemplar.com/index.php?n=Article.PumpedStorage [Accessed 17/09/2015 2015].

Energy Exemplar. 2013b. *PLEXOS Wiki - Stochastic Monte Carlo Method* [Online]. Energy Exemplar. Available:

http://wiki.energyexemplar.com/index.php?n=Stochastic.MonteCarloMethod [Accessed 30/09/2015 2015].
Energy Exemplar. 2015. *PLEXOS Wiki - Nash-Cournot Competition* [Online]. Energy Exemplar. Available: http://wiki.energyexemplar.com/index.php?n=Article.NashCournot [Accessed 25/05/2015 2015].
Lozanov, T. 2014. *Possible Generation Implications of Operational Constraints for Investment Modelling in the National Electricity Market.* Bachelor of Engineering (Electrical), University of New South Wales.
Riesz, J. & MacGill, I. 2013. 100% Renewables in Australia - Will a capacity market be required? *3rd International Workshop on the Integration of Solar Power into Power Systems.* London.
ROAM Consulting 2012. ROAM report on Wind and Solar modelling for AEMO 100% Renewables project. Australian Energy Market Operator.
Vithayasrichareon, P. & MacGill, I. F. 2012. A Monte Carlo based decision-support tool for assessing generation portfolios in future carbon constrained electricity industries. *Energy Policy,* 41**,** 374-392.
Vithayasrichareon, P., Riesz, J. & MacGill, I. 2015. Impact of High Variable Renewable Generation on Future Market Prices and Generator Revenue. *IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC).* Brisbane.
Wright, M. & Hearps, P. 2010. Australian Sustainable Energy - Zero Carbon Australia Stationary Energy Plan. Beyond Zero Emissions, University of Melbourne Energy Research Institute.

8. Acknowledgements

Preparation of this paper was supported by the School of Photovoltaic and Renewable Energy Engineering, UNSW. Energy Exemplar for provided an academic license for PLEXOS. The authors would like to acknowledge Ben Elliston from the Centre for Energy and Environmental Markets for his assistance in developing the input generation portfolio.