Examining the Viability of Energy-Only Markets with High Renewable Penetrations

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***Abstract*—An illustrative energy-only electricity market model was used to explore possible market outcomes in scenarios with 100% renewable energy, including high penetrations of low operating cost variable technologies such as wind. Results indicate that even in scenarios with wholesale market prices at $0/MWh in the majority of periods, all technology types can precisely recover their costs via energy-only wholesale market revenues, if the generation mix is least cost optimized. Importantly, this includes the variable generation technologies. Furthermore, it is illustrated that exercise of market power is not essential for the modelled energy-only market; generators recover costs based upon short run marginal cost (SRMC) pricing alone (representing a highly competitive market), as long as the Market Price Cap (MPC) is set appropriately to reach the desired level of unserved energy. The appropriate setting for the MPC depends upon the cost parameters for the highest SRMC plant (often open cycle gas turbines).**

***Index Terms*—Energy-only market, renewable generation**

I. Introduction

A growing number of studies have indicated that 100% renewable power systems are technically feasible at costs that, while higher than present, appear manageable. For example, the Australian Energy Market Operator (AEMO) recently released detailed modelling of 100% renewable scenarios for the Australian National Electricity Market (NEM) [1], consistent with previous analysis conducted at the University of NSW [2], and by Beyond Zero Emissions with the University of Melbourne [3].

A key objective of these modeling efforts has been to find renewable mixes that meet the existing NEM reliability criterion of 0.002% unserved energy (USE). As such, they raise, but do not themselves address, questions regarding the viability of the existing energy-only wholesale gross pool market arrangements of the NEM with 100% renewables.

The analysis presented in this paper aims to explore the issue of system adequacy in a 100% renewables market, meaning the market mechanisms that manage the quantity of installed generating capacity, and the adequacy of this installed capacity to meet anticipated demand. Specifically, we ask whether the present NEM mechanisms for system adequacy have the potential to function effectively in a 100% renewables system.

Electricity market resource adequacy models have been fiercely debated over the past decade [4] and the issue remains unresolved [5, 6]. Proponents of energy-only market models argue that they avoid the need for increasingly prescriptive regulations, and create better incentives for operations and investment [7, 8]. On the other side, proponents of capacity market models argue that an energy-only market cannot operate satisfactorily on its own; regulatory demand for energy, operating reserves and capacity are required [9, 10]. This paper aims to extend and inform this debate through examination of energy-only markets in the context of very high renewable penetration.

The majority of renewable technologies have short run marginal costs (SRMC) close to zero. Given that efficient energy-only wholesale markets should drive preference revealing bidding, where generators offer the majority of their power at their plant's SRMC, a competitive electricity market composed entirely of renewable technologies could be expected to have a high proportion of very low priced periods. This is already being observed in depressed wholesale electricity prices in a growing number of electricity industries with significant renewables, including the NEM region of South Australia (which features a wind penetration approaching 30% by energy) [11].

Adding further complexity, some renewable technologies are variable in nature, meaning that their availability varies over time. This complicates conceptual understanding of the fundamental operation of energy-only markets with significant penetrations of such technologies.

These two factors have led some to suggest that energy-only markets cannot provide adequate investment signals in a system with a large proportion of renewable generation. It is a commonly held view that an energy-only market with prices at or close to zero for the majority of the time, and including large quantities of variable generation, would not be an attractive environment for new generation investment [12]. This has perhaps contributed to the fact that a number of electricity markets, including those of Great Britain, Germany and the

Texas ERCOT system, are now in stages of implementing or considering a move away from an energy-only system to alternative market models [12].

II. Model Description

In order to examine the investment incentives in a 100% renewable electricity market, a simple market optimization model was developed. This model applies conventional deterministic load duration curve methods to calculate the least cost installed mix of dispatchable (firm capacity) technologies depending upon the cost profiles (capital and operating) of those plant, and a given demand profile.

The model calculates the total annual costs of each firm capacity technology available, as a function of the number of hours of the year that it operates, as illustrated in Figure III.1 (A). This is then mapped onto the load duration curve, with the lowest cost technology selected to supply the load at each capacity factor, as illustrated in Figure III.1 (B). The hourly load profile from the calendar year 2010 in the Australian NEM was applied. The least cost optimal capacity installed for each technology was then calculated from the vertical axis representing demand (GW). Wholesale electricity prices were calculated for each hour of the year, based upon the SRMC of the marginal operating plant in each period, as illustrated in Figure III.1 (C). This assumes a highly competitive system, with no opportunity for the exercise of market power.

USE was included as another "technology type", with zero fixed costs, and a SRMC at the market price cap (MPC). The MPC was adjusted to set the amount of USE to the reliability standard of the system (in this study assumed to be 0.002% USE per annum, as currently applied in the Australian NEM).

Wind generation was modelled as an hourly aggregate generation trace, sourced from modelling results by Elliston et al. [2]. Total wind generation in the NEM in each hour was subtracted from the demand in the relevant hour, prior to calculation of the (net) residual demand duration curve. The total capacity of wind installed was iteratively adjusted by scaling the aggregate wind trace to minimize total system costs.

The model is broadly designed to represent the technology options and market design of the Australian NEM. However, the model does not capture many of the complexities of this market, and in particular does not attempt to represent plants with energy storage such as hydro, incumbent plant and operational constraints such as minimum operating levels, ramp rates or unit commitment timeframes and costs. It is entirely deterministic with no consideration of demand, plant performance or cost uncertainties. Nor does it consider the full spectrum of technologies that may be available in future.

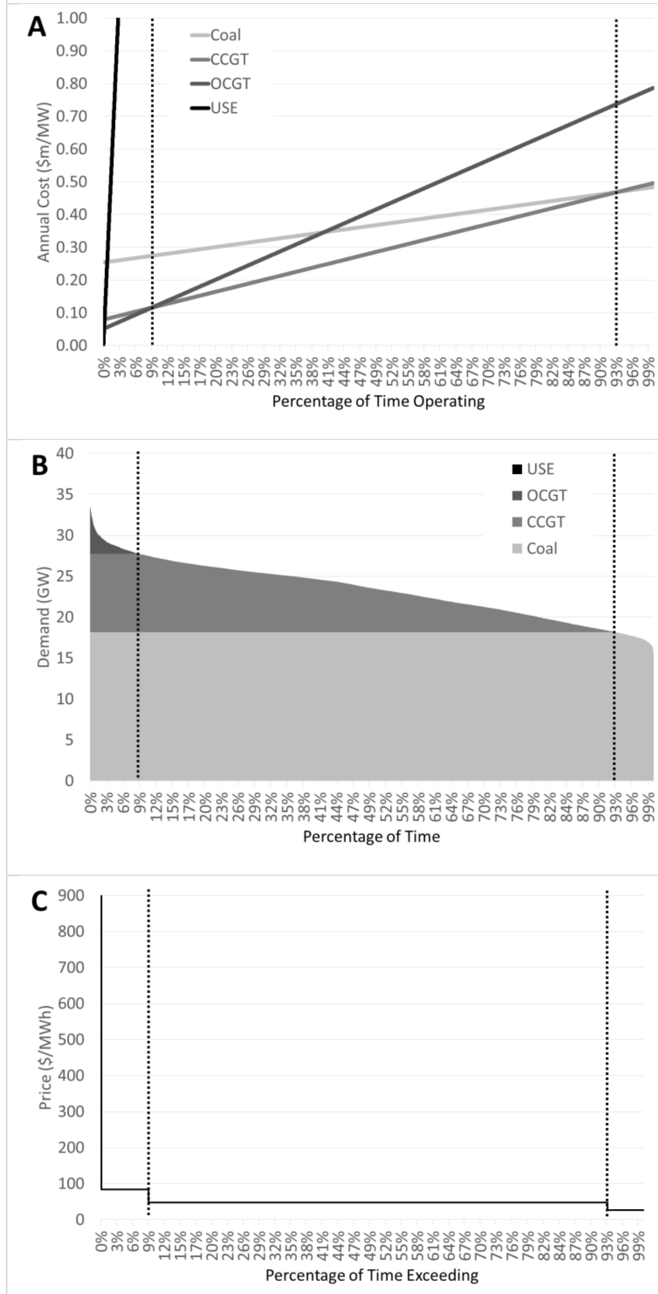
III. Results

A. *Fossil fuel scenario*

A scenario that utilizes conventional fossil fuel technologies is presented first, to demonstrate the operation of the model, and to provide a point of comparison for later scenarios with high proportions of renewable technologies.

Figure III.1 illustrates model results for a scenario involving fossil fuel technologies, with costs sourced from the Australian Government's 2012 Energy Technology Assessment (AETA) [13], applying a 5% discount rate. Cost assumptions are listed in Table I. The following technologies were included: black coal-fired supercritical plant, combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). No carbon price was applied, and the gas price was assumed to be $6/GJ, with a 20% uplift for the lower capacity factor OCGTs.

Figure III.1 - Least cost optimized results for Fossil Fuels Scenario



The model finds that the least cost solution involves 18 GW of coal-fired capacity, 9.5 GW of CCGT, and 5.2 GW of OCGT. An MPC of $4,300/MWh is required to meet the reliability standard of 0.002% USE.

TABLE I. COST ASSUMPTIONS FOR FOSSIL FUEL SCENARIO

	Capital + FOM ($/MW/yr)	SRMC ($/MWh)
Coal	253,721	26
CCGT	79,085	48
OCGT	51,032	84
USE (MPC)	-	4,300

CCGT plant are at the margin for 85% of periods, setting the wholesale price to $48/MWh. During these periods, the high capital cost coal-fired plant earned 74% of annual revenue, and recovered 63% of fixed costs (fixed operations and maintenance (FOM) and annualized capital). The remaining 37% of fixed costs were recovered during higher priced times when OCGTs were at the margin (9% of the time and 18% of fixed cost recovery), or during the 11 hours when USE was occurring, and the price was at the MPC (19% of fixed cost recovery).

This example serves to highlight that even in systems with conventional fossil fuel technologies, high capital cost plant such as coal-fired plant can earn a significant proportion of their fixed costs during a very small number of periods when prices are at the MPC. Thus, as has been previously established, it is important that the MPC is set sufficiently high, to avoid the missing money problem.

Analysis of generator revenues in this scenario reveals that all technology types earn annual spot market revenue precisely equal to 100% of their costs (to within the rounding error of the model). This is due to the fact that the composition of the system has been optimized for least cost, and demonstrates the fundamental principles of the energy-only market.

B. 100% Renewable Scenario 1

To explore the operation of a possible 100% renewable energy market, a system composed of geothermal, biogas gas turbines (GTs) and wind was developed, with cost parameters as listed in Table II. Costs were sourced from the Australian Energy Technology Assessment [13], with a 5% discount rate applied. Wind generation costs were reduced from AETA estimates to ensure that this technology entered the market under a least cost optimization, so that its impact could be examined. A realistic system for the Australian market is likely to also include a range of solar technologies and hydro generation; these were not included in this analysis since they created additional complexity and were not necessary for demonstrating the underlying principles of interest.

Results for this scenario are illustrated in Figure III.2. With these assumptions, the least cost system includes 15 GW of geothermal plant, 16 GW of biogas GTs, and 16 GW of wind capacity. The MCP required to meet 0.0002% is now $5100/MWh. The relatively high capital cost of geothermal plant means that it is lower cost to run biogas turbines for a significant proportion of the time, despite a relatively high SRMC of $92/MWh. The biogas GTs are at the margin for 86% of periods, meaning that the geothermal plant can recover high fixed costs over a substantial number of periods. Only 14% of geothermal fixed costs remain to be recovered during the seven hours at which the system is experiencing USE.

TABLE II. COST ASSUMPTIONS FOR 100% RENEWABLE SCENARIO 1

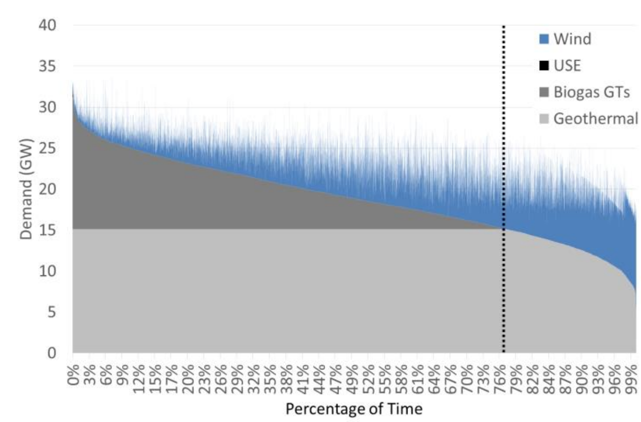
	Capital + FOM ($/MW/yr)	SRMC ($/MWh)
Geothermal	655,360	0
Biogas GT	35,662	92
Wind	140,000	0
USE (MPC)	-	5,100

As in the fossil fuel system, all technologies recover precisely 100% of their annual costs through energy-only market revenues. This outcome occurs because the composition of technologies has been optimized to the least cost mix required to serve the load, to the specified reliability standard (0.002% USE per annum).

Importantly, this outcome is also true for the variable wind generation in the system. The variability of wind is apparent in Figure III.2, which shows the generation of aggregate system wind in each period. Wind generation is generally operating less in the higher price periods, and more in the lower priced periods. This is a result of the fact that the wind generation adjusts the ordering of periods in the net demand duration curve. Periods with higher wind generation will naturally tend have a lower residual demand due to the impact of the wind itself, and will therefore appear further to the right in the residual demand duration curve.

Even though wind generation is operating at lower levels during higher priced periods, wind generators recover precisely 100% of their annual costs through energy-only market revenues, as observed for other technology types.

Figure III.2 - Least cost optimized results for 100% Renewable Scenario 1



Wind generation in this scenario earns only 2% of revenues during periods when USE is occurring, and the wholesale price is at the MPC. This is significantly less than the proportion earned by geothermal plant during USE events (14% of annual revenues), due to the fact that wind generators are operating at low levels during these extreme peaking events. Wind generation is only operating at an average capacity factor of 7% during the seven hours of USE that occur. The majority (98%) of wind revenues are earned during periods when the biogas GTs are at the margin, since these periods occur frequently (77% of the time).

C. 100% Renewable Scenario 2

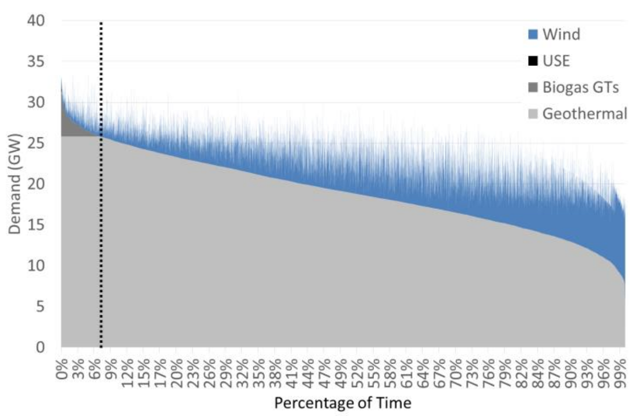
Some high renewable power systems are likely to feature prices at or close to zero for the majority of time. Therefore, this scenario aims to explore the operation of the energy-only market under these circumstances.

For this scenario, the capital cost of biogas GT plant was increased so that the least cost generation mix involved a smaller proportion of biogas GTs (marginal in only 8% of periods). In this system, the price is set to \$0/MWh in 92% of periods by geothermal plant being at the margin. Also, the cost of wind generation was reduced, to ensure that a similar quantity of wind generation was included in the least cost mix. Assumptions are listed in Table III.

TABLE III. COST ASSUMPTIONS FOR 100% RENEWABLE SCENARIO 2

	Capital + FOM (\$/MW/yr)	SRMC (\$/MWh)
Geothermal	655,360	0
Biogas GT	600,000	92
Wind	44,000	0
USE (MPC)	-	86,000

Figure III.3 - Least cost optimized results for 100% Renewable Scenario 2



In this scenario, the least cost generation mix included 26 GW of geothermal plant, 5.5 GW of biogas GTs and 15.5 GW of wind generation. Results are illustrated in Figure III.3.

Importantly, even in this scenario where the wholesale price is zero 93% of the time, all generator types earn precisely 100% of their costs through energy-only market revenues. The geothermal plant earn 2% of revenues during periods when the biogas GTs are at the margin, and 98% of revenues during the seven hours at the MPC. Since the geothermal costs are the same as in the previous scenario, this means the MPC must increase significantly to \$86,000/MWh.

Importantly, the wind technology still also earns precisely 100% of costs through wholesale market revenues, as in the previous scenario. Note that the capital cost of wind was reduced significantly to ensure that this technology featured in the low cost mix. This was necessary because wind only provides additional value to the system when it operates during the brief periods when the GTs are operating (7% of the time). This will only occur when high wind coincides with high demand. In all other periods wind provides no value to the system since it only acts to displace geothermal generation, which also has zero variable costs. As for the geothermal plant, the majority of wind revenue (89%) is earned during periods when USE is occurring, despite an average capacity factor of only 7% during these periods.

IV. DISCUSSION

A. Energy-only markets with 100% renewables

Consistent with previous economic analysis [14, 15], these results illustrate that, in theory, an energy-only market may be able to operate successfully even with very high renewable penetrations. Even if the price is zero for the majority of periods, the market does, in theory, allocate revenues in proportion to technology costs such that that all technology types achieve precise cost recovery. This also applies for variable generation such as wind. Note, however, that this analysis only applies for energy-only markets with the optimized least cost generation mix. If the underlying cost drivers change then the system will no longer be optimized for least cost, and incumbents may well make windfall gains or losses. Barriers to exit and entry may, of course, inhibit the market from shifting to the new least cost equilibrium.

This analysis means that investment incentives are, in theory and under a range of significant assumptions, accurately signaled to market participants in an energy-only market, even if the price is zero for the majority of the time. If slightly less wind is installed than the optimal (least cost) amount, the incumbent wind generation receives a windfall gain, making investment in additional wind generation attractive. If slightly more wind than optimal (least cost) is installed, incumbents receive less than cost recovery, encouraging retirement of capacity towards the optimal amount. This applies similarly for all technology types.

Thus, the question of whether an energy-only market can function with very high renewable proportions becomes a more subtle one. Operating in a market where a large proportion of revenues are earned during a very short period will exacerbate risks and increase hedging premiums, which ultimately increases costs to consumers. In the present NEM, participants manage the risk associated with a high MPC of \$13,100/MWh via contractual arrangements, and this approach may remain viable in an increasingly volatile market. These issues were discussed in more detail in an earlier paper [16], and will be explored further in future work.

B. Market power is not necessarily essential

Another key principle illustrated by this modelling is the fact that the exercise of market power is not a fundamental requirement for an energy-only market to avoid the "missing money" problem. This model did not include any representation of market power, assuming that prices were simply based upon the SRMC of the marginal technology, as they would be in a highly competitive market. This modelling demonstrates that a market of this nature can function successfully, in theory, if the MPC is set appropriately for the desired USE level.

C. Methodology for setting the MPC

In order to avoid the "missing money" problem, the MPC must be set appropriately. Two factors influence the appropriate value for the MPC in our simplified model: the cost properties of the highest SRMC plant (in this case the GTs), and the shape of the demand curve, which dictates the number of hours of system operation at the MPC required to meet the reliability standard. For cost recovery for the highest SRMC GT, the following must be true:

$$\mathrm{Capex}_{GT} = (\mathrm{MPC} - \mathrm{SRMC}_{GT}) \times \mathrm{hrs@MPC}$$

Thus, the appropriate setting for the MPC to achieve cost recovery for the OCGTs will be:

$$\mathrm{MPC} = \frac{\mathrm{Capex}_{GT}}{\mathrm{hrs@MPC}} + \mathrm{SRMC}_{GT}$$

This modelling demonstrates that although this MPC is only dependent upon the cost parameters of the highest SRMC plant, this MPC also allows cost recovery by the other generation types in the mix in the least cost optimized system. This has important implications for the methodology for setting the MPC for real markets; for example, in the NEM, complex market simulations are conducted to determine the required level of the MPC. These simulations aim to find the MPC level that allows an OCGT to achieve cost recovery, and do not explicitly consider the revenues of other plant in the mix. This modelling suggests this is a reasonable approach. In markets where there is the potential for the exercise of market power, it may also be appropriate to take this into account in the setting of the MPC.

D. Limitations

This modelling has many limitations. Firstly, as mentioned above, it does not consider all of the real-world practicalities of operating electricity markets, which will need to be considered carefully in future work. This modelling also does not consider the lumpiness of investment, which is significant in electricity markets, and is particularly influential in small power systems. Significantly, uncertainties such as the impacts of forced outages and other future uncertainties are also not considered, but are an important aspect of detailed reliability modelling.

Furthermore, this analysis does not include consideration of energy-limited plant, such as hydro generation and solar thermal with storage. Energy limits significantly complicate the manner in which plant offer their capacity into the market, since they can face large opportunity costs. Biogas GTs could also be considered energy limited if there were limitations on the total fuel resource available due to competition with agriculture and other land uses, which are very likely to apply in reality. Future work will aim to explore these issues in more detail.

V. CONCLUSIONS

This modelling identifies no theoretical barriers to the successful operation of an admittedly highly simplified energy-only market with very high renewable penetrations. The challenges are likely to be more subtle and practical in nature.

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