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Impact of Carbon Price on Transition Rate of Renewable Sources in Australia

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Abstract

Australia's National Electricity Market (NEM) is experiencing a rapid transformation toward renewable electricity generation. To ensure energy adequacy, reliability, and security, the possible future electricity generation portfolios should be comprehensively investigated. Over the past few years, the significant decline in the cost of renewable energy generation has led to a huge increase in the share of these technologies in the electricity market. As a result, the need for supporting mechanisms, such as carbon cost, has shrunk. However, the share of carbon-intensive fossil fuel generation technologies, such as coal based generation units, in the Australian generation mix is still significant. Moreover, despite a huge increase in the share of renewable energy generation, fossil fuel generation technologies will still exist in different generation mix scenarios. Therefore, recognising the environmental impact of different generation technologies could be of interest to electricity industry stakeholders. One mechanism to advance this recognition is to impose carbon cost on generation technologies to promote cleaner electricity production.

This paper investigated the impact of imposing different values of carbon cost on the optimal generation portfolio. The study is based on the Integrated System Plan (ISP) model and dataset provided by Australian Energy Market Operator (AEMO). The power system planning tool PLEXOS was used to find the most economical generation mix under different carbon cost scenarios. The base case was simulated using the published "neutral ISP" model and data, followed by a simulation of the same scenario with the introduction of different carbon costs. The results showed that imposing higher carbon cost does not lead to reduction of fossil fuel capacity, but significantly decreases the participation rate of capacity factors. It was also evident from the simulation results that imposing the carbon price leads to higher capacity of renewable energy technologies as well as battery storage. The need for higher battery capacity is a direct result of the higher share of intermittent renewable energy generation. The storage fleet mainly comprises pumped hydro technology, mainly because of lower development cost of pumped hydro technology compared to utility battery storage (Per Mega Watt). The results also showed an increase in the share of gas-based technology in the generation fleet as well as in the total industry cost, by more than 1.9 billion dollars in the final year of simulation compared to AEMO's estimation.

1 Introduction

A recent Integrated System Plan (ISP) model presented by the Australian Energy Market Operator (AEMO) suggested that generation portfolios in the order of 80% renewable energy would be feasible in the Australian National Electricity Market (NEM) by 2040 [2]. Although the NEM's geographically extensive network and Australia's rich solar and wind resources make high variable renewable energy (VRE) penetrations possible, technical and economic issues persist.

In this paper, we investigated potential effects of imposing carbon price on the National Energy Market and changes to future NEM scenarios. The PLEXOS Integrated Energy Model [1] was selected, given its widespread use by market operators in international electricity jurisdictions, including the AEMO [2]. In this study, three cases with carbon prices of 0, 25 and 50 $\$/tonne\ CO_2$ were investigated.

Section 2 of this paper provides a theoretical basis for the study and the methodology used; Section 3 presents results and analysis, and Section 4 provides the conclusions and remarks.

2 Context

In the last century, fuel price and access were the main factors considered while establishing power plants and energy systems. Power plants were built in locations near cities. This was because cheap fuels, such as coal, and less sophisticated systems, such as coal power plants, were available almost everywhere. Moreover, supplying fuel for power plants is cheaper than developing transmission lines and there was no law preventing construction of power plants close to cities [3].

However, this approach started to change owing to many factors: the development of cities; the imposition of laws that required power plants to be built at a safe distance from cities, thereby increasing transmission costs; the increased price of fuel; the emergence of new energy generation technologies; and, more recently, the urgent need to incorporate renewable energy sources to mitigate climate change. The treatment of the energy sector as a subject of national scale and long-term implications developed complex math problems that have many answers but only a few economically practical ones. Finding the most economical solution to build and run the entire electricity system requires consideration of capital and operational cost of all generation technologies as well as building new transmission lines and optimising the system's parameters to achieve the objective. However, this would be subject to a set of physical and economical constraints, including generation technology types, size and dispatch schedule. In this paper, the most economical solution for the Australian electricity system under different assumptions was investigated, and its implications are discussed.

2.1 Definition

The process of optimally adding new generation and transmission lines to grids based on increasing demand is called capacity expansion modelling. The expansion plan describes a group of new generation and transmission facilities. Generation-expansion optimisation aims to find an expansion plan that would result in the lowest combined operating, capital and reliability cost incurred by the operator over the course of the modelled time horizon, which is achieved by optimising the total cost of meeting demand. The total cost comprises capital investment for new generation, dispatch cost of existing and new generation, retirement cost, and cost of building new transmission lines [4].

2.1.1 Dispatch cost

The price is formulated by collection of time intervals with varying lengths at nodes where demand and generation are present [4]. Dispatch cost can be calculated by multiplying the generation cost and demand and then summing the product over the region for which the model is being used with the all-time intervals. The resulting equation is given below:

$$C_d = \sum_{t=1}^{T}\sum_{g=1}^{GA} CGA_{t,g} + \sum_{g=1}^{G} CG_{t,g} \times E_{t,g} + \sum_{r=1}^{R} (CP_{t,r} \times USE_{t,r}) \qquad \text{Equation 1}$$

where c_d = dispatch cost, T = number of time intervals, R = number of regions, GA = available generators, CGA = cost incurred by generator g to supply energy at time interval t, G = number of generators, $CG_{t,g}$ = generator g cost to operate at time interval t, $E_{t,g}$ = amount of energy generator g supplies at time interval t, $CP_{t,r}$ = penalty cost for unavailable energy in region r, at time interval t., and $USE_{t,r}$ = unavailable energy in region r, at time interval t.

2.1.2 Generation investment cost

Whenever there is insufficient generation to meet demand and requirements for minimum reserve, the model includes new generation units that should be established to prevent the supply shortfall. The cost of this new generation is calculated using the following equation:

$$C_{ng} = \sum_{ng=1}^{NG} \sum_{t=1}^{T} CA_{t,ng} \qquad \text{Equation 2}$$

Where, C_{ng}= capital cost required to add new generation units, T = total number of considered time periods, NG = total number of options available for new generation units, $CA_{t,ng}$ = amortised capital cost of generation, which varies depending on the size of the time interval under consideration.

The cost required to establish new generation units is compensated by lower operational cost resulting from lower fuel or fixed or variable cost, as the model is able to select the option with lowest total cost for a specific time and region. The ability to choose an appropriate time and region becomes available by amortising the cost of adding new generation over the modelled timeframe.

2.1.3 Generation unit retirement

Generation unit retirement is costly for both the operator and the market that the generation unit is a part of. The retirement can occur for two main reasons: First, the existing generators can and should exit the market if the modelled market signals indicate that costs can be minimised by switching to new generators with a combination of lower fuel, emission or operating, and power transmission costs owing to availability of a location proximal to demand. Second, generation units also can be withdrawn from participation in the market due to ageing, reduced efficiency and increased variable and maintenance cost incurred by the operator.

Equation 3 shows the total cost of retirements:

$$C_{RG} = \sum C_{rg} \qquad total\ cost\ of\ plant\ retirements. \qquad \text{Equation 3}$$

Where, C_{rg} = unit retirement cost.

The cost of retirement incurred by the operator can be considered as a capital cost at the retirement time or the end of the unit's lifetime. This cost is more significant for sophisticated generation units such as nuclear plants.

The cost incurred by the market on retiring an existing generation unit can be compensated by using more efficient generation sources with lower operational cost. This becomes possible owing to lower fuel, variable, fixed or carbon costs, which provide the model with the ability to select from options with the lowest total cost that are appropriate for a time interval.

2.1.4 Transmission line augmentation

It should be considered while optimising the cost that establishing new generation units usually needs new transmission lines. Augmenting transmission cost is so significant (and usually irreversible) that every generation expansion model tries to avoid building a generation unit far from demand centres, unless it is more cost-effective to do so. This situation usually occurs when a renewable generation unit can only be established far from the operating network due to such as proper geographical locations or low fuel prices, such as those of coal or gas, encourage the establishment of generation units in a particular area.

The cost of a new transmission line can be calculated by Equation 4:

$$C_{nt} = \sum_{nt=1}^{NT} \sum_{t=1}^{T} CA_{t,nt} \qquad \text{Equation 4}$$

Where C_{nt} = cost to add transmission network, T = number of time intervals considered in the model, NT = number of available new generation units and $CA_{t,nt}$ = amortised capital cost for augmenting new transmission.

2.1.5 Optimisation

Generation capacity expansion modelling aims to minimise the total cost of providing stable and reliable energy according to demand. The total cost can be written as a sum of dispatch, generation expansion, generation retirement and transmission augmentation costs (equations 1, 2, 3 and 4). Stable and reliable operation of power systems is ensured by establishing reserved capacity, which is used in case of generation failure. While the minimum reserve level requires a specific lower limit on capacity level to be available in a region at all times, it does not specify the source from which the capacity is to be supplied; this allows regions to source the capacity and energy from either their own generation units or other regions. It also allows regions to conduct reserve sharing, which allows outsourcing of reserve capacity from neighbouring regions. Fine-tuning generation and outsourcing energy and capacity from other regions is practiced to find the most economical solution [5].

2.2 Effects of carbon price on the optimisation

Owing to the detrimental impacts of CO_2 emission, a carbon tax has been introduced in some electricity industries to promote cleaner production. The carbon tax (also known as carbon price or carbon cost) is applied to the amount of CO_2 emission produced by a generation unit (usually fossil fuel-based technologies). The introduction of carbon tax results in higher costs of generation for emission-intensive technologies; this promotes higher utilisation of renewable energy sources. The carbon tax policy was adopted in Australia from July 2012 to July 2014. Although the policy has not been in place since July 2014, recently, there have been discussions about re-introducing it to accelerate transition to carbon-free electricity. Therefore, in this paper, we investigated the impact of carbon tax on the optimisation of electricity planning.

Adding a carbon price to the optimisation platform will change not only the result of optimisation but also the way sub-factors including dispatch cost, generation expansion, generation retirement and transmission line augmentation interact with each other [6]. Imposing a carbon price will increase the dispatch cost of fuel-based plants, thereby promoting utilisation of renewable energy sources. This can also result in the early retirement of fossil fuel-based generation, thereby incurring additional cost on the owner and the market and creating opportunities for renewable plants to expand. As a result of carbon tax, unsurprisingly, the total cost of generation expansion planning will also increase [7]. Utilising new generation sources may also result in the need for new transmission lines, resulting in a further increase of the total cost.

2.3 Methodology

Three scenarios were modelled in the PLEXOS Integrated Energy Model [1, 8]. For modelling, the currently installed generation plants in the NEM were considered and three carbon price scenarios (0, 25 and 50 $\$/tonne\ CO_2$) were introduced.

The first scenario, with zero carbon price, represented the current neutral scenario model developed by AEMO, where no explicit carbon price is integrated but indicative state renewable energy sources and emission targets are implemented. Moreover, it should be noted that in the model published by AEMO, generation units' retirement dates are provided to the software as input, and therefore retirement decisions are not optimised. A reason for adopting this approach by AEMO, might be the fact that a certain amount of dispatchable capacity should be participating in order to provide fast frequency response and emulated inertia [10].

The second scenario was modelled with 25 $\$/tonne\ CO_2$ carbon price. This price was derived from the previous carbon price used in the NEM with some modifications based on factors such as increased price of electricity after removing carbon price and a new approach offered by AEMO to expedite the transition toward renewable sources.

The third scenario was modelled with 50 $\$/tonne\ CO_2$ carbon price to investigate the effect of higher carbon price on generation and the rate of transition to renewable energy sources. In addition to the three scenarios, a different scenario with very high cost of expansion for pumped hydro was also modelled in order to investigate the effect of limited utility storage in NEM.

In all the scenarios, the model was developed using publicly available data[1] provided by AEMO as part of the AEMO ISP plan, with a neutral growth rate of renewables and solved with a 1-hour resolution [9] with the linear embedded solver in PLEXOS (Xpress-MP 34.01.03) for a 25-year term plan. Since capacity expansion modelling is a long-term plan, the results are shown on a yearly basis, for the duration from 2018 to 2043.

3 Results

This section presents the results of the abovementioned scenarios. The ISP model comprises several hundreds generation units; therefore, to facilitate the visualisation, the technologies are grouped as follows:

- Coal (black and brown coal)
- Hydro
- Pumped hydro
- Solar photovoltaic
- Gas (Open cycle gas thermal and closed cycle gas thermal)
- Utility scale battery storage
- Wind
- Liquid fuels + biomass + gas peaking

Three main outputs are presented in this section: generation, installed capacity and generation cost. Generation is total energy (GWh) provided by each category every year. Installed capacity is the aggregated capacity of existing and new generation units. Generation cost is the cost of generating electricity for each generation technology.

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[1] In the scenario developed for investigating the effect of limited pumped hydro generation, the generation expansion model is increased and does not match the data publish by AEMO.

3.1 Generation

Figure 1 shows the energy generation projection of all case studies, with carbon price varying from 0 to 50 $\$/tonne\ CO_2$. Total generation (to meet demand) in all scenarios is similar, but the contribution by different technologies varies in each case. A significant difference across the scenarios is observed in coal generation units' operation, with a decrease in generation from 54.3 TWh (terra watt hours) in neutral case to 48.7 TWh in the case with carbon price of 50 $\$/tonne\ CO_2$ in 2043. This shortage in generation would be covered by gas thermal units in the early years (2019–2022), while wind and solar energies seem to be contributing to meet the demand in the later years (2022–2033). After this stage, owing to the retirement of a lot of coal generation units, again there is an increase in gas participation, which is replaced again by wind and solar energies in the following years. With a high share of wind and solar generation, a need for storage is evident from the results, hence, pumped hydro units would start to participate significantly during this stage. A higher carbon price has increased the share of renewable energy. For example, in 2020, there is more than double the solar generation in the high carbon price scenario (50$\$/tonne\ CO_2$) as compared to the medium carbon price scenario (25$\$/tonne\ CO_2$). Contrary to expectations, the contribution of coal generation units does not vary much among the studied cases. This stems from AEMO's policies regarding coal generations units' retirement.

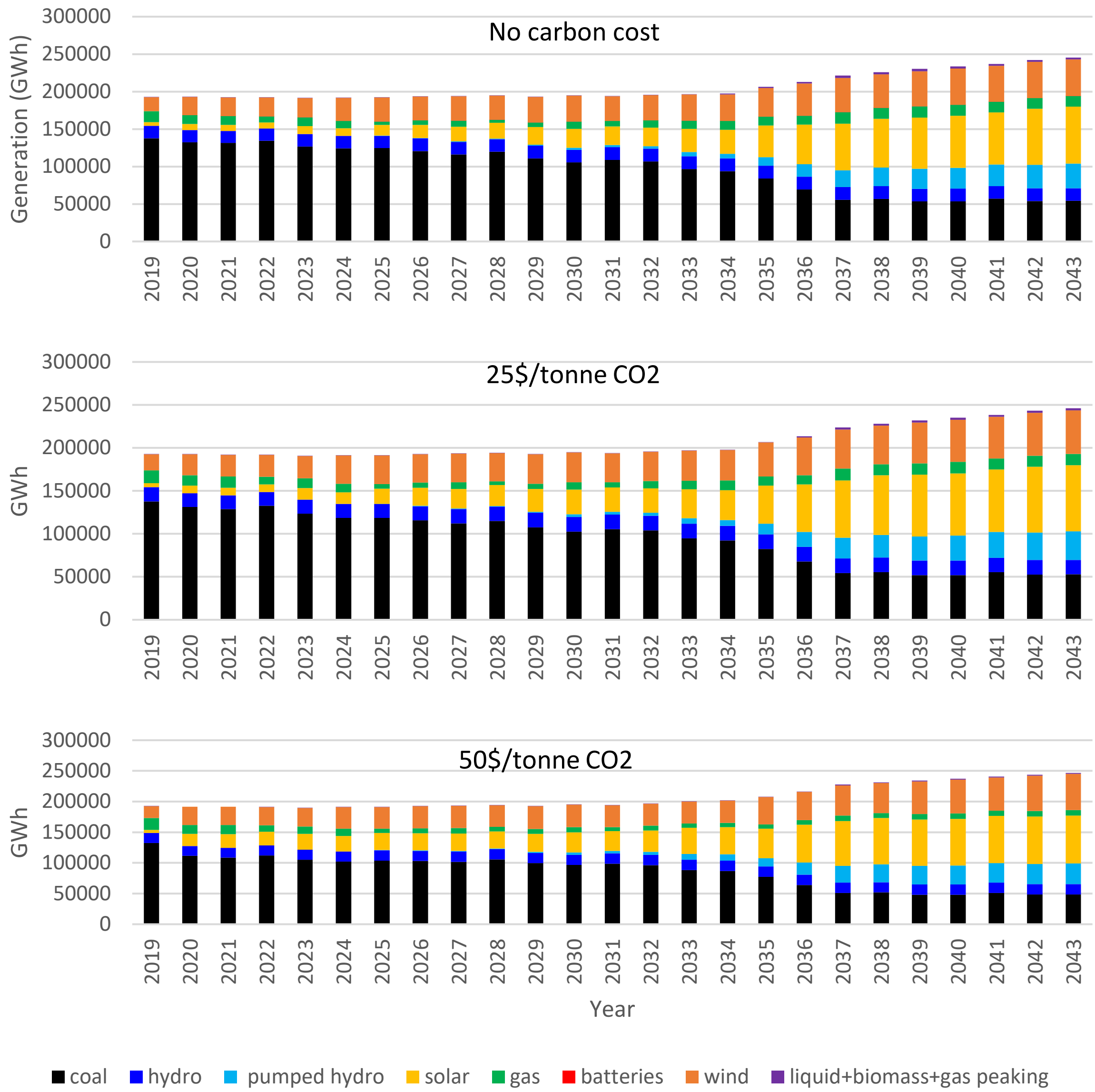

Figure 1. Generation in three scenarios

In Figure 2, to compare the effect of imposing carbon price on the rate of transition, the contribution of renewable energy sources (solar and wind) to the total generation is shown for all the case studies. Imposing carbon price shows more significant impact over the initial years. Over the first three years, the difference between zero and 50 $\$/tonne\ CO_2$ carbon cost is about 8–10%; this difference shrinks over the following years and almost settles on about 3% over the final years. This rapid increase in renewable energy contribution in the early stages will create an opportunity for new technologies, such as battery storages, to participate. This is discussed in detail in section 3.3.

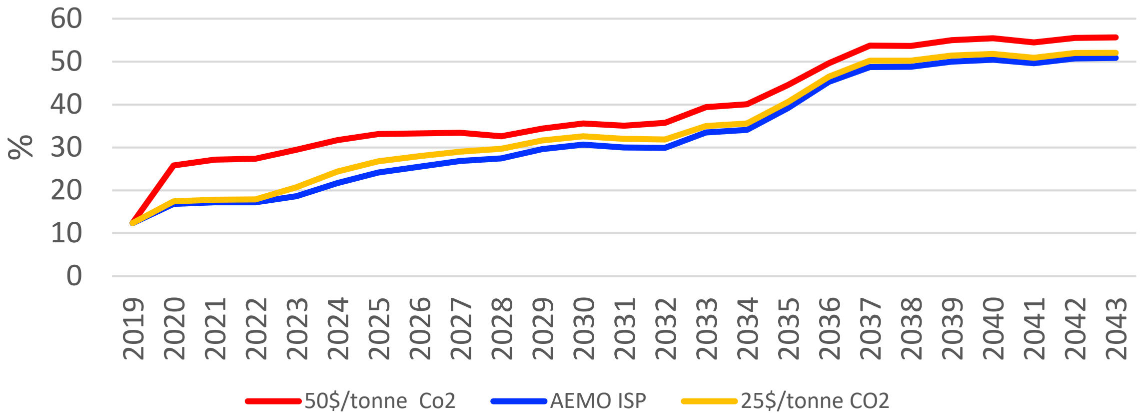

Figure 2. Ratio of generation of renewable energy sources to their respective generation mix

3.2 Installed capacity

Figure 4 shows the installed capacity in the three scenarios. Unsurprisingly, higher carbon price increases the capacity of renewable energy technologies. After the retirement of coal generation units, an increasing trend is seen on installation of renewable generation units; the final share of renewable energy from the total installed capacity changes by approximately 4% across different case studies. It should be noted that although the capacity of coal generation units is not significantly different in the scenarios, their contribution to energy generation is different (as shown in Figure 1). This means the coal generation units have not retired (the retirements are decided by AEMO depending on factors such as system strength), but their utilization has decreased owing to the higher cost of generation resulting from increased carbon price. To compare the rate of change towards the renewable energy industry, the ratio of combined installed capacity of renewable energies (wind and solar) to their respective total installed capacity in each case study is shown in Figure 3. Again, imposing carbon price is seen to have a more significant impact on the initial years (up to 7% change) as compared to the final years (~2%).

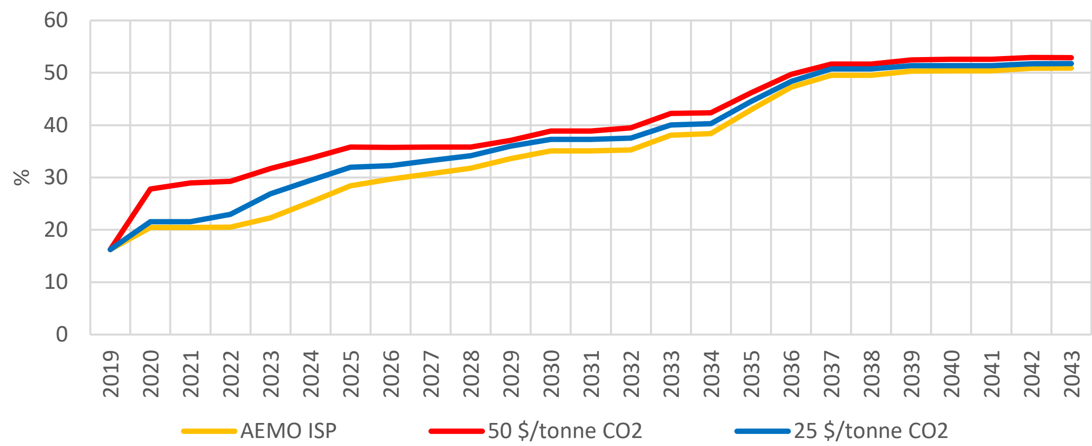

Figure 3. Ratio of installed renewable energy source to their respective total installed capacity

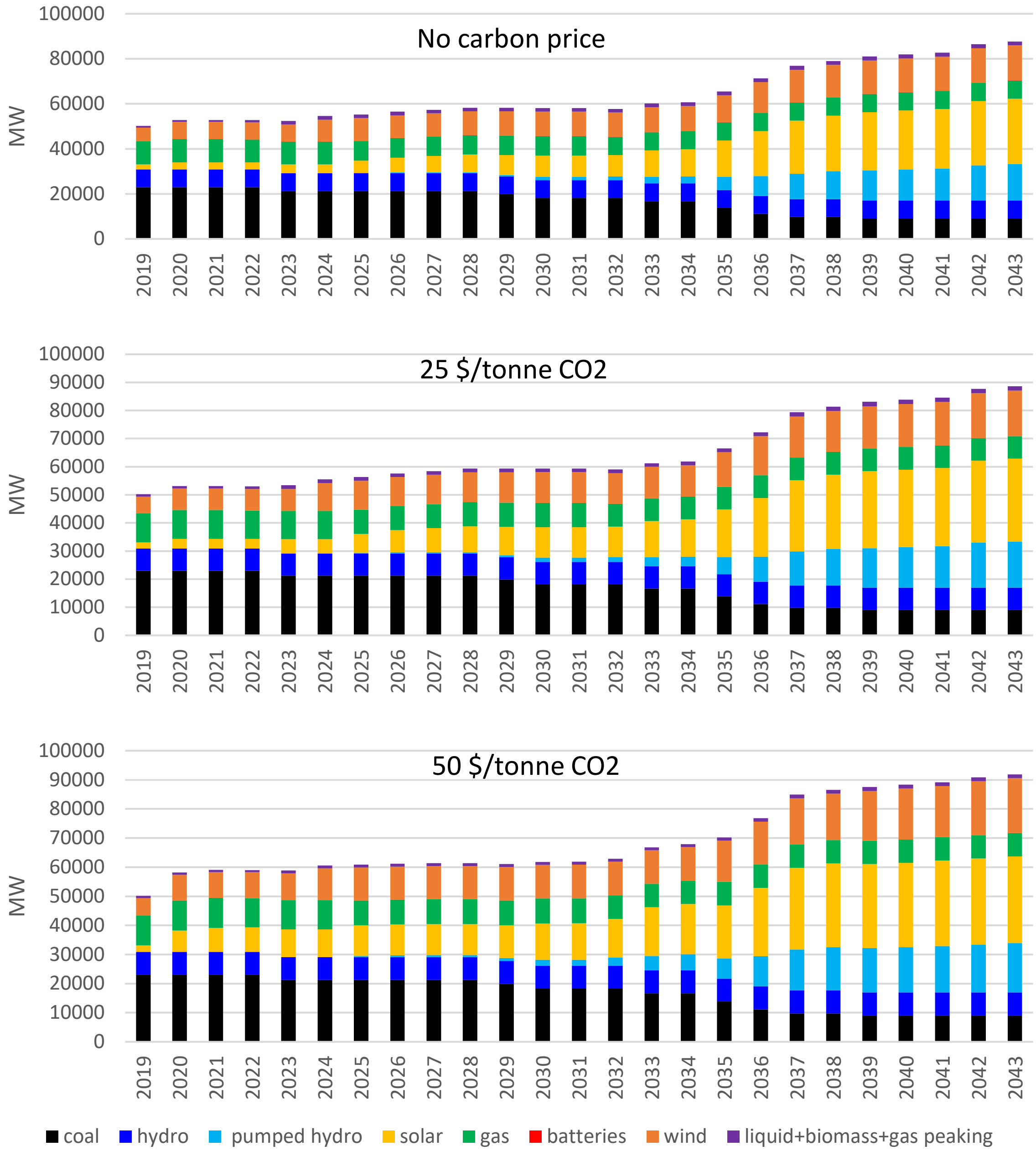

Figure 4 Installed capacity in different scenarios

3.3 *Industry cost and generation cost*

Generation cost is the revenue received by generation units that can be used as a measure to analyse the behaviour of the markets. However, the carbon cost is not received by the generation units, and therefore it is not included in estimation of generation cost in this study. The total industry cost, conversely, includes the carbon cost. Imposing carbon price not only increases the industry cost of the NEM but also has an impact on the generation cost. Figure 5 shows the generation cost of each case study. The total generation cost does not show a material difference across all three scenarios, but the generation cost of different technologies varies by imposing the carbon cost. The generation cost of carbon-intensive technologies is seen to reduce from 85% to 29% over the course of the simulation. Figure 6 shows the generation cost for three scenarios. It can be seen that generation cost would not vary significantly in 2043 among all generations but would alter the path that leads the market there. Even though gas generation units (shown in green) and liquid + biomass + gas peaking units (shown in purple) would experience a reduction during the final years of the simulation, they would have a larger contribution during the early years (corresponding to the carbon price). This will provide various opportunities for development and participation of new generation technologies, such as battery storages, since these technologies will provide compensation for the inherent intermittent shortcomings of renewable energy's. This opportunity is seen to contribute to 28% (2 billion dollars) of generation cost in the early stages and up to 31% (3.58 billion dollars) in the final stages (including pumped hydro).

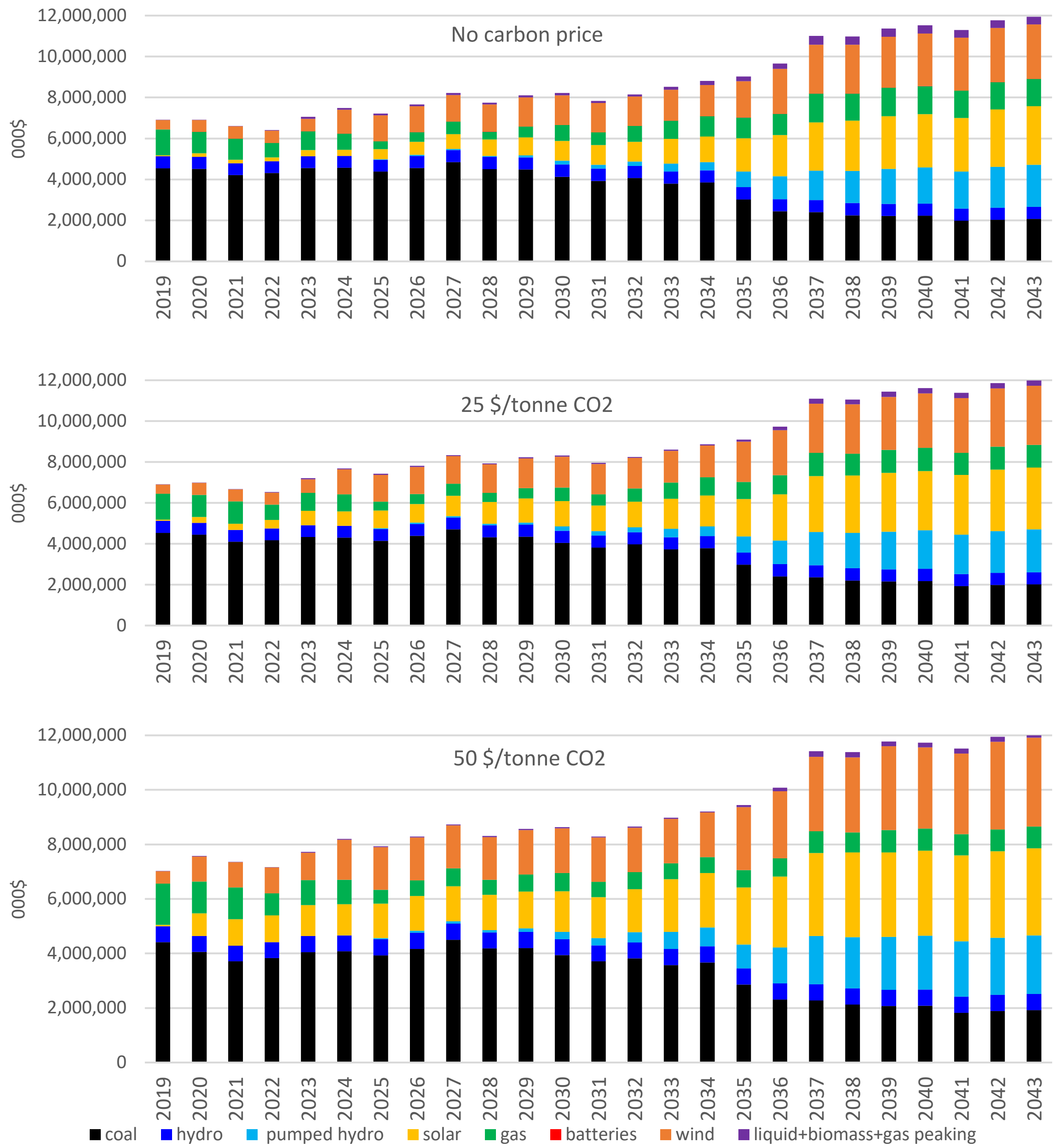

Figure 5. Impact of carbon price on generation cost

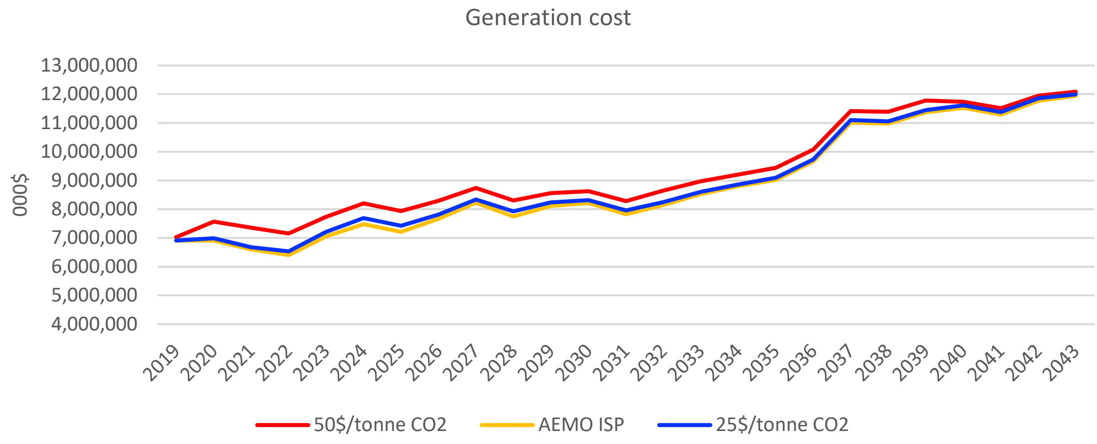

Figure 5. Generation cost

4 Conclusion

In this paper, we investigated the effects of imposing carbon price in NEM to expedite the transition toward renewable energy sources. Three different scenarios with carbon prices of 0 , 25 and 50 $\$/tonne\ CO_2$ were developed and simulated to compare the impact of different carbon costs on a least-cost generation mix solution. By comparing the outcomes of different case studies, it was seen that introducing a meaningful carbon price might not significantly change the total installed capacity of various generation units in NEM in the distant future, but it will change the contribution of each generation (capacity factor of each technology) and will also increase the total generation cost.

Conversely, imposing carbon price will change the market's approach toward renewable energies; from a reactive one, which starts to employ renewable sources after a coal generation unit is retired, to a proactive one, where renewable sources are employed as a means to reduce conventional energy's participation rate. Imposing carbon price might not change the result, but it will change the timings and increase the rate of transition, which is important as climate change is a "atmospheric stock" issue; this means early emission reductions are important.

Another important outcome of imposing the carbon price includes creation of opportunities for new energy storage technologies, such as large-scale batteries. Considering the inherent intermittent shortcomings of using renewable energies, employing energy storage technologies is inevitable. Hence, renewable energy technologies have the ability to become major participants in the NEM.

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