Peer Reviewed
2017 Solar Research Conference

Fast Frequency Response Markets for High Renewable Energy Penetrations in the Future Australian NEM

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Abstract

The growth of non-synchronous variable renewable energy generation poses new operational challenges for the Australian National Electricity Market (NEM). One such challenge is managing grid frequency as power system inertia falls. Inertia is a property of a power system provided by rotating masses in generators and loads which are coupled to the system's electrical frequency. Coal, gas and hydro generators provide inertia to the NEM but wind and photovoltaic (PV) generators do not. Inertia is a valuable property because it lowers the rates of change of frequency (RoCoF) the power system experiences. Inertia acts against frequency disturbances caused by contingencies, such as the sudden loss of a large thermal plant, instantaneously, automatically and proportionally, hence reducing RoCoF and assisting in frequency restoration.

With the prospect of falling inertia and hence higher RoCoF as wind and PV penetrations grow, an important issue for the NEM is whether its present regulatory frameworks ensure sufficient frequency control in the very short term. The NEM's current frequency control ancillary services (FCAS) include 6 second, 60 second and 5 minute contingency markets. In the future, additional measures for procurement of inertia or alternative fast frequency response resources with response times in the order of 1 second may be necessary to secure the power system.

The study presented in this paper explores procurement of such resources through market arrangements with a dynamic requirement for total system inertia. A unit commitment model is used to simulate NEM dispatch in MATLAB with differing penetrations of wind and PV generation and a dynamically set requirement for total system inertia. In some modelling scenarios, in addition to synchronous generators, inertia may be sourced from devices such as synchronous condensers. The study also considers *synthetic inertia* from wind generators as a potential resource for providing fast frequency response. A number of mechanisms for recovering the costs of payments for inertia are also modelled.

This study provides new insights into the potential impacts of market-based approaches to deliver inertia or very fast frequency response. In particular, the costs of inertia can be reduced by:

1. Allowing synthetic inertia from wind generators to be bid into inertia markets.
2. Installation of synchronous condensers.
3. Increasing the system's allowable RoCoF.
4. Using a cost recovery mechanism that penalises generators in proportion to their relative requirement for tight frequency controls.

These results suggest that commercial frameworks that accommodate a variety of existing and emerging technologies are likely to be most suitable for the NEM in a high renewable energy future.

1. Introduction

The Australian Energy Market Operator (AEMO) manages both the physical and commercial operation of Australia's National Electricity Market (NEM) (AEMO, 2015b). In the NEM and in many power systems around the world, renewable energy generation is increasing, particularly from solar photovoltaics (PV) and wind, while reliance on carbon-intensive fossil-fuel generation is decreasing. This is evident from capacity investment and retirement trends. Since 2012, around 1.5 GW of new wind capacity has been added to the NEM, accounting for 60% of all new generation capacity. During this same period, around 1.8 GW of coal plant has been retired (AER, 2015). These trends are projected to continue. It is predicted that 3-8GW of additional coal capacity withdrawal will occur by 2034-2035 and 20-35 GW of renewable capacity will be added to the NEM (AEMO, 2015c), including a growing penetration of utility-scale PV generation.

One of AEMO's primary objectives is system security; meaning that power system operation is maintained within technical limits and is secure against potential disturbances. An important aspect of system security is control of grid frequency. AEMO aims to keep grid frequency as stable as possible around 50 Hz by ensuring the ongoing balance of supply and demand. This is done every 5 minutes through the dispatch of energy markets so that generation meets expected demand. Within each 5-minute period, AEMO maintains the supply-demand balance and manages grid frequency through a set of Frequency Control Ancillary Service (FCAS) markets (AEMO, 2015a).

FCAS markets are divided into regulation markets and contingency markets. Regulation markets allow AEMO to manage small-scale variability and uncertainty of load and generation. Contingency markets allow AEMO to respond to the sudden outage of large generators, loads or transmission lines (contingency events) and correct the supply-demand imbalance over a short timeframe. Contingency markets are a major focus of this study. At present, there are contingency markets operating at 6 second, 60 second and 5 minute periods for both frequency raise and lower services in each of the 5 regions of the NEM. Frequency raise services utilise technologies which can rapidly decrease load or increase generation, whereas frequency lower services involve rapid increases in load or decreases in generation. FCAS market participants' compliance with market rules is enforced by the AER and non-compliant participants may be subject to civil penalties (AER, 2014) (AEMC, 2017). This allows AEMO to operate this market framework and implement its frequency control objectives.

The displacement of thermal generation (coal and gas) with PV and wind generation is likely to affect AEMO's ability to meet its frequency control objectives in the future (AEMO, 2016b; AEMO/Electranet, 2014; AEMC, 2016; Gannon, 2014). This is because thermal generators provide inertia (resistance to changes in frequency) to a power system, whereas wind and PV generators do not. If inertia reached a level of scarcity such that the current FCAS market framework did not allow AEMO to meet its frequency control objectives, then this framework may need to be modified.

Under the current FCAS market framework, market participants who provide inertia or very fast frequency response (FFR) on a timescale of less than 6 seconds are not directly financially rewarded for doing so (Riesz et al., 2015). Thus, implementing market mechanisms to incentivise inertia provision in the NEM may be an effective strategy to ensure system security in a future NEM with high renewable energy penetration. The question of how to design such market mechanisms is addressed in the study presented in this paper.

In order to consider the design and potential implications of an inertia market, it is important to understand which technologies have the ability to provide it and its value to different participants in that market. This is the focus of Section 2 of this paper. Section 3 details the design of several market mechanisms for the provision of inertia and the method of simulating the operation of these markets in the NEM. Section 4 discusses the assumptions underlying the modelling and the limitations of the findings. Section 5 highlights significant results from the simulations and Section 6 highlights the broader implications of this study and suggests possible avenues for future work.

2. Inertia and Fast Frequency Response

2.1 Definition of Inertia

Power system inertia comes from the kinetic energy of spinning masses whose rotational frequency is directly coupled to the electrical frequency of the grid. When an imbalance between supply and demand occurs, inertia creates resistance to frequency change proportional to the size of the imbalance. This limits the Rate-of-Change-of-Frequency (RoCoF) caused by power imbalances, including contingency events (Gannon, 2014).

The relationship between inertia and RoCoF in the NEM is shown in Equation 1 (AEMC, 2016). Equation 1 shows that the RoCoF reached immediately after a contingency event is proportional to the size of the contingency event and inversely proportional to the level of system inertia.

$$RoCoF = 25\left(\frac{\Delta P}{I}\right), \qquad \textbf{Equation 1.}$$

where $RoCoF$ is the rate of change of frequency (Hz/s), ΔP is the size of the power imbalance arising from a contingency event (MW) and I is the system inertia (MW.s).

The inertial response of synchronous plant is both immediate and inherent (AEMO, 2016b). Synchronous plants provide a fixed level of inertia dependent on the particular technology and their rated capacity, not their power output (Gannon, 2014) (ERCOT, 2014).

2.2 Sources of Inertia and Fast Frequency Response

Various sources of inertia and similar FFR resources are described in the coming section. Their key properties are summarised in Table 1.

Synchronous generators including coal, gas and hydro powered plants are the largest sources of inertia in the NEM. Other technologies providing inertia in electricity industries around the world include nuclear, biomass and concentrating solar thermal plant.

Induction generators also provide inertia to a power system, although this inertia is generally less than for synchronous generators per unit of power delivered. Notable induction generators in the NEM are type 1 and type 2 wind turbines. These old-style turbines are either fixed speed or semi-variable speed and account for approximately 1GW of capacity. The installed capacity of these types of turbines is not expected to increase in the NEM (AEMO, 2013).

Synchronous condensers are similar devices to synchronous generators except that their shaft is not connected to a turbine but can spin freely. They are unique devices in the way that they provide inertia to a system without generating or consuming power, except for a small parasitic loss. Thermal plant can be converted to synchronous condensers, which may be an appealing option for decommissioned power stations (Gannon, 2014; Fogarty and LeClair, 2011).

Synchronous condensers are currently installed in the NEM to assist with voltage control ancillary services (VCAS) (AEMO, 2015a).

In a similar way to generators, **synchronous motors** and **induction motors** contribute inertia to a power system. Estimates for international power systems suggest that the contribution of loads to system inertia are small but not negligible. For example, an estimate for Great Britain is that loads contribute 8-25% of total inertia, depending on load and generation (Tielens and Van Hertem, 2016). The contributions of motors to total power system inertia in the NEM are treated as negligible in the study presented in this paper.

Most modern **wind turbines** (type 3 and type 4) cannot provide inertia to a power system. This is because they are connected to the grid via a power-electronic interface and do not rotate at a speed dependent on the grid frequency (AEMO, 2013). However, modern turbines can emulate an inertial response by providing what is called *synthetic inertia*. Synthetic inertia is delivered when the power electronic interface of a turbine is configured to access the rotational energy stored in a turbine following the detection of a high RoCoF (Miller et al., 2017).

A key distinction between synthetic and conventional inertia is that initiation of a synthetic response requires a short time-period for the detection of a RoCoF event. There is a trade-off between a short detection period, which would make the response more like conventional inertia, and RoCoF measurement reliability. A high RoCoF could be detected over a single cycle (0.02s) at minimum, but it is more practical to average the RoCoF over a longer period (~0.1s) to avoid false triggering from local frequency variations or other disturbances (Riesz, 2016a).

Synthetic inertia from wind turbines is one of many FFR services which have response times of less than one second but are distinct from conventional inertia. Similar responses can also be provided by photovoltaic plants, high-voltage direct current (HVDC) transmission lines, batteries, electrical loads and static synchronous compensators (STATCOMs) (Rahmann and Castillo, 2014; Li et al., 2014; NationalGrid, 2016; Miller et al., 2017; McGarrigle and Leahy, 2014). Synthetic inertia from wind turbines is considered in the modelling in this study, whilst all other alternative sources of FFR are not.

The inertia delivered by a device depends on its inertia constant, which is the ratio of the kinetic energy stored in the rotor of the device when operating at rated capacity to the output at rated capacity. The inertia constants of various devices in the NEM is shown in Table 1.

Table 1. Inertia Constants and FFR Requirements for Devices in the NEM

Device	**Service Offered**	**Inertia Constant (s)**	**FFR Requirement**
Coal	Inertia	6	High
Open-cycle Gas Turbine (OCGT)	Inertia	6	High
Combined Cycle Gas Turbine (CCGT)	Inertia	6.5	Highest
Wind (Type 1 and 2)	Inertia	4	High
Wind (Type 3 and 4)	Synthetic Inertia	4	Lowest
Hydro	Inertia	3	Lowest
Synchronous Condenser	Inertia	1.25-8	High
Synchronous Motor	Inertia	2-5	High
PV	NA	NA	Low

(Piriz et al., 2012; Agranat, 2015; PPAEnergy, 2013; Liu et al., 2014; Miller et al., 2017; AEMO, 2013; Muljadi et al., 2012)

Since type 3 and 4 wind turbines provide synthetic inertia, the listed inertia constant (4s) is not directly comparable to that of other devices in the table. However, higher levels of synthetic inertia are known to reduce the levels of conventional inertia needed for power systems to meet their frequency objectives (Riesz, 2016b). Hence, to the extent allowed by the relevant frequency objective, conventional and synthetic inertia can be considered economic substitutes.

2.3 Requirement for Inertia and Fast Frequency Response

Inertia is cumulative and shared across an alternating current (AC) interconnected power system. This means that the providers of inertia in the NEM are effectively providing inertia to the entire system (Gannon, 2014). Notably, Tasmania is connected to the NEM via a HVDC interconnector (*'Basslink'*) and so cannot contribute to or benefit from the inertia available on the mainland (ETAC, 2010). Hence, the NEM region of Tasmania was excluded from the study presented in this paper.

Different participants in the NEM require different levels of frequency control and hence do not place equal value on the presence of inertia. In general, synchronous plants (coal, OCGT, CCGT, synchronous motors) have a relatively high requirement for FFR. This is due to the thermal and physical stresses placed on moving parts during high RoCoF episodes (Agranat, 2015). Table 1 shows the FFR requirements for various technologies in the NEM (Piriz et al., 2012; Agranat, 2015; PPAEnergy, 2013; Liu et al., 2014; Miller et al., 2017).

3. Methodology

For this study, the operation of different markets for inertia in the NEM was simulated using a MATLAB model. It was envisaged that these markets could operate as part of a restructured NEM in 2030. Hence, modelling parameters such as the generation mix were selected to reflect reasonable values for 2030.

Due to the high computational requirements of the model, it was only feasible to simulate one week of market operation for this study. An historical summer peak period of 21/02/2016 to 27/02/2016 was chosen to provide the demand profile. This was a period with high energy demand and relatively high demand for contingency FCAS, which was deemed an appropriate test for the inertia markets being considered, since the power system is under considerable strain under these conditions. The profile through the simulation period is shown in Figure 1.

Figure 1. Demand and Contingency Requirement Profile

This study assumes a NEM-wide RoCoF standard is in effect. This is not the case in practice. For each 5-minute interval in the simulations, the RoCoF standard and the contingency requirement were used to determine the requirement for inertia in accordance with Equation 1. The contribution of a single unit toward meeting this requirement was dependent on its online capacity and its inertia constant. This is shown in Equation 2.

$$Inertia\ (MW.s) = Inertia\ Constant\ (s) * Online\ Capacity\ (MW) \qquad \textbf{Equation 2.}$$

Preliminary modelling showed that, even at a RoCoF standard of ~1.5 Hz/s, optimal unit commitment would keep generating capacity online in a way which avoids activating the inertia market or paying any costs associated with providing inertia. The tight RoCoF standard of 0.5-0.6 Hz/s was chosen to ensure that inertia markets were continually required throughout the simulation period. It was deemed that this would provide the greatest insights into their operation. For reference, a RoCoF standard of 0.5 Hz/s is currently in effect in Ireland, however this standard is under review and may be relaxed to accommodate increasing penetrations of variable renewable generation in the future (Eirgrid/SONI, 2016). In contrast, Quebec has a requirement that all generators connected to its transmission system tolerate a RoCoF of 4 Hz/s (HydroQuebec, 2009). Such a high RoCoF allowance is possible in Quebec because its generation is 99% hydro (CEA, 2014) and hydro generators can accommodate relatively large frequency excursions (Table 1).

3.1 Inertia Market Design

Three inertia market designs are considered in this study. In all cases, the price of inertia is set in accordance with section 3.1.1. The three markets differ in terms of how the costs of providing inertia are allocated amongst NEM participants, as described in section 3.1.2.

3.1.1 Pricing

If the inertia provided by dispatched units is insufficient to meet the required inertia, then additional units must be kept online in order to meet the inertia requirement, and the inertia market operates in the model. In each dispatch interval, inertia-providing units are scheduled to provide inertia in ascending cost order until the inertia requirement is met. The partially-dispatched or marginal provider of inertia sets the inertia price for the dispatch interval. Additional units not otherwise generating are providing inertia to the system at a cost proportional to the cost of operating at their minimum level (Equation 3).

$$Inertia\ Provision\ Cost\ \left(\frac{\$}{MW.s}\right) = \frac{Cost\ of\ Operating\ at\ Minimum\ Level(\$)}{Inertia\ Constant\ (s) * Online\ Capacity\ (MW)} \qquad \textbf{Equation 3.}$$

3.1.2 Cost Recovery

The first inertia market design is called **causer pays**. In this market generators are rewarded if their inertia constant exceeds the average requirement and charged if their inertia constant falls short of the average requirement. Payments are proportional to the difference between the average required inertia constant and the inertia constant delivered by a generator. This approach is reasonably consistent with current approaches to cost recovery for regulation FCAS in the NEM.

The second market design is called **consumer pays** and this market directly allocates the costs of inertia to energy consumers. This approach is similar to that used to pay for Network Control Ancillary Services (NCAS) in the NEM (AEMO, 2015a).

The third market design is called **user pays** and it allocates costs to generators in proportion to their relative requirement for tight frequency controls. This market values inertia in a way which is very different to traditional methods of valuing grid services. This market would be difficult to implement in practice partly because of the challenges of determining the extent to which different market participants require tight frequency controls.

These markets are summarised in Table 2.

Table 2. Summary of Inertia Markets

Market	Causer Pays	Consumer Pays	User Pays
Who pays?	Generators whose inertia constant is less than the required average.	Consumers.	All generators.
How much do they pay?	An amount proportional to the difference between their inertia constant and the requirement.	An amount proportional to the price of inertia and the requirement for inertia.	An amount proportional to their requirement for FFR.
Who earns?	Generators whose inertia constant is greater than the required average.	All generators who provide inertia.	All generators who provide inertia.
How much do they earn?	An amount proportional to the difference between their inertia constant and the required inertia constant.	An amount proportional to their inertia constant.	An amount proportional to their inertia constant.

The effects of each of the inertia markets detailed in Table 2 were compared to a base case in which there was no requirement for inertia and hence no inertia market.

3.2 *Modelling Inputs*

The NEM was modelled as a system of 7 large generators, one of each of the major types of generating plant in the NEM: CCGT, OCGT, Black Coal, Brown Coal, Hydro, Wind and PV. One of the key sensitivities explored in the modelling was the generation capacity mix of wind and PV generation in 2030 (Table 3). This mix was borrowed from Vithayasrichareon et al. (2015), and reflects their assumptions about generation and load in 2030. It was assumed that all wind turbines were able to provide synthetic inertia but not conventional inertia, reflecting the capabilities of type 3 and 4 wind turbines.

The capacities for the remaining generators are shown in table 4. These capacities represent a possible 2030 capacity mix based on current capacities (AER, 2016) and adjusted for committed withdrawals and new capacity (AEMO, 2016a). Given significant future uncertainty around capacity mixes, additional capacity withdrawals in high renewable energy future scenarios were not captured in modelling. In practice, additional withdrawals would likely occur as redundant plant became unprofitable.

Table 3. 2030 Wind & PV Capacity

RE Penetration (%)	Wind Capacity (GW)	PV Capacity (GW)
15	3	3
30	8	5
45	15	8
60	21	16
75	28	25
85	34	31

Table 4. 2030 Dispatchable Generator Capacity Mix

Generator	Capacity (MW)
CCGT	2844
OCGT	9964
Black Coal	15516
Brown Coal	4998
Hydro	5889

Table 5 shows the costs and operating constraints that were used to model each of the generators in the NEM based on the 2014 Fuel and Technology Cost Review from Acil-Allen Consulting.

Table 5. Generator Costs and Operating Constraints

	CCGT	OCGT	Black Coal	Brown Coal	Hydro	Wind	PV
Short-run Marginal Cost (SRMC)[1] ($/MWh)	48.54	91.69	28.54	9.99	6.90	15.00	0.00

Fuel Cost ($/MWh)	41.54	81.69	24.54	4.99	0.00	0.00	0.00
Variable O&M Cost ($/MWh)	7.00	10.00	4.00	5.00	0.00	0.00	0.00
Minimum Operating Level as % of Total	0.00	0.00	40.00	40.00	0.00	0.00	0.00
No Load Fuel Consumption as % of Total	30.00	30.00	10.00	10.00	0.00	0.00	0.00
Minimum Operating Level Fuel Consumption as % of Total	30.00	30.00	36.00	36.00	0.00	0.00	0.00
Fixed Cost of Operating at Minimum Operating Level[1] ($/MW/h)	12.46	24.51	10.43	3.80	0.00	0.00	0.00
Ramp Rate (%/hr)	144.0	400.00	80.00	80.00	NA	NA	NA
Ramp Rate (%/5 minutes)	12.00	33.33	6.67	6.67	NA	NA	NA
Cost of Providing Inertia[1] ($/MWs/h)	2.49	4.90	2.98	1.08	0	0	NA

[1]estimated values

3.3 MATLAB Algorithm

In order to simulate the effects of possible inertia market designs on different participants in the NEM, a backwards dynamic programming (BDP) algorithm was developed to find the optimum (least cost) path of states of the system throughout the chosen time period. In each 5-minute dispatch interval, a system state is defined by the online capacity of all generators. The cost of operating the system in each state will depend on the combined cost of providing enough generation to meet demand and enough inertia to meet the inertia requirement. The dispatched capacities of wind, PV and hydro generation were assumed to follow their historical profile, and the BDP algorithm was applied to CCGT, OCGT, brown coal and black coal.

From one 5-minute period to the next, any given system state can only transition to a limited number of other states due to generator ramping constraints (Table 5). The BDP algorithm used in this study accounts for these constraints and, beginning in the second-last dispatch interval, finds the lowest cost path from each state to the final dispatch interval. The BDP algorithm then steps back one dispatch interval and finds the lowest cost path of states from the third-last to the second-last time period. By stepping back in this fashion until the first time period, the algorithm eventually determines the cheapest path of states from each initial state. Then, by selecting the initial state which has the lowest cost state path, the algorithm effectively optimises the unit-commitment throughout the simulation period. This approach is much more computationally efficient than an exhaustive enumeration approach, in which every possible path of states from every initial state would need to be determined.

4. Modelling Assumptions and Limitations

The simplification of the NEM from 336 registered generators (AER, 2017) to 7 large generators, and the omission of transmission constraints or other inter-regional considerations significantly reduced the complexity of the simulation task, but, naturally, also lowered the resolution of the modelling results and hence their practical relevance to the NEM. Additionally, by imposing a stringent RoCoF standard on the system and choosing a peak summer demand week, the costs of inertia provision were likely to have been significantly inflated compared to a more moderate RoCoF standard in an average week.

The results detailed in Section 5 of this paper should be viewed in light of these limitations. As such, general trends in the results are likely to be more meaningful than the numerical outputs of the modelling.

5. Results

5.1 Impact of Inertia Markets on Renewable Energy Penetration

Compared to the base case with no inertia market the *consumer pays* market did not materially affect the net renewable energy penetration reached over the simulation period. At high penetrations, the *consumer pays* market tended to favourably dispatch hydro over PV since hydro generators provide inertia and PV generators do not. The increase in PV spill (curtailed generation which is not supplied to the grid) and the increase in hydro generation offset each other, meaning the net renewable energy penetration was not affected in the *consumer pays* market. Wind has a higher SRMC than hydro, so an increase in hydro generation did not increase wind spill.

In contrast to the *consumer pays* market, the increase in PV spill in the *causer pays* market materially reduced the renewable energy penetration achieved over the simulation period. Both of these effects are shown in Figure 2.

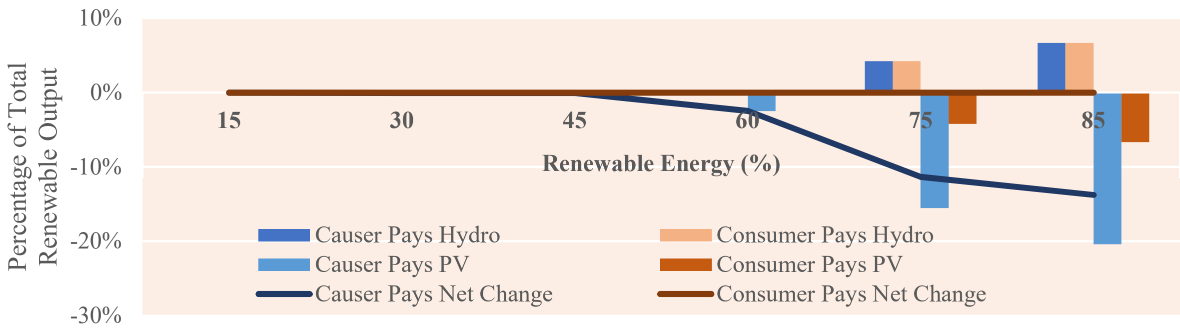

Figure 2. Change in Hydro and PV Output Compared to Base Case by Market

The *causer pays* market was also found to increase wind spill, further decreasing the renewable energy penetration achieved over the simulation period in this market.

5.2 Strategies to Reduce Costs of Inertia Provision

This section details variations in **3 modelling sensitivities** which reduced the total costs of operating the energy and inertia markets over the simulation period.

In accordance with Equation 1, the **RoCoF standard** and the level of inertia required in a power system are inversely proportional. Thus, an incremental rise in the RoCoF standard from 0.5 to 0.6Hz/s is a relaxation of a constraint which is expected to reduce the amount of inertia required in a power system and the associated costs of providing this inertia. Figure 3 illustrates how relaxing the RoCoF standard affected total system operating costs for the NEM during the simulation period. The effect of relaxing the RoCoF constraint is slightly more pronounced for the *causer pays* market than the *consumer pays* market. For both markets, total operating costs are reduced by a greater magnitude as the renewable energy penetration increases.

Simulations were carried out with and without 10,000 MW.s of **synchronous condenser capacity** installed in the NEM. Adding synchronous condensers has the effect of marginally increasing demand due to the parasitic loss of synchronous condensers. It also has the effect of reducing the inertia requirement.

Figure 4 indicates a reduction in total system operating cost in both markets from adding synchronous condenser capacity. The simulations thus suggest that the costs of increased demand due to parasitic losses from synchronous condensers is more than offset by the cost savings from reducing the inertia requirement. Of course, this assessment does not factor in the capital costs of synchronous condensers.

As discussed in section 2.2, **synthetic inertia** from wind turbines can provide FFR. Increasing the levels of synthetic inertia can hence decrease the requirement for conventional inertia. In simulations where synthetic inertia was valued as equivalent to conventional inertia, the cost of meeting an inertia requirement was found to decrease. Further, synthetic inertia increased the profits of wind generators by providing an additional revenue stream to payments from the energy market. This is shown in Figure 5.

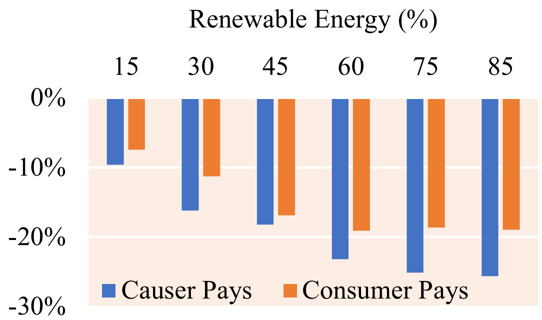

Figure 3. Change in Total System Operating Cost (%) from Relaxing RoCoF Standard from 0.5 to 0.6 Hz

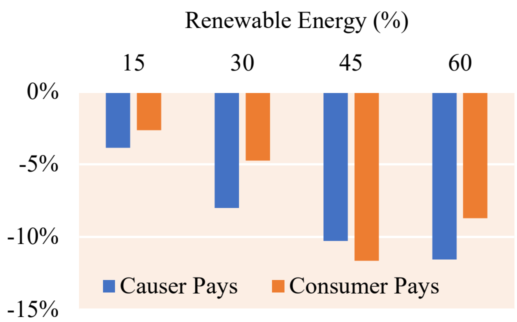

Figure 4. Change in Total System Operating Cost (%) from Adding 10,000 MW.s of Synchronous Condenser Capacity

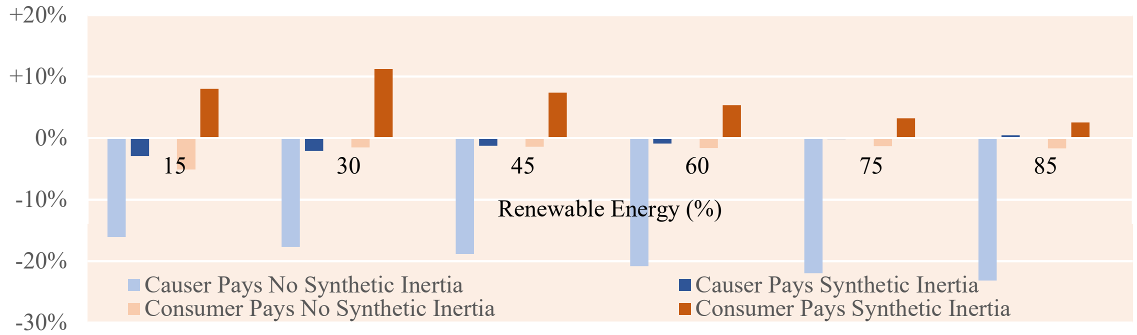

Figure 5. Change in Wind Profits (%) Compared to Base Case - Synthetic Inertia

5.3 Overall Effects of Inertia Markets

Table 6 summarises the effects of the different inertia markets on NEM participants. Results are displayed in general terms relative to the other inertia markets.

Table 6. Summary of Inertia Market Impacts by Participant

NEM Participant	Causer Pays	Consumer Pays	User Pays
Consumers	Costs increased most.	Costs increased slightly less than causer pays.	Costs increased least.
Black Coal	Profits increased least and profits decreased at low	Profits increased most.	Profits increased moderately.

	renewable energy penetrations.		
Brown Coal	Profits decreased at low renewable energy penetrations. Profits increased most at high penetrations.	Profits increased most at low renewable energy penetrations. Profits increased moderately at high penetrations.	Profits increased moderately at low renewable energy penetrations. Profits increased least at high penetrations
CCGT	Profits increased least.	Profits increased moderately.	Profits increased most.
OCGT	Profits increased least.	Profits increased moderately.	Profits increased most.
Hydro	Profits decreased at low renewable energy penetrations. Profits increased least at high penetrations.	Profits increased greatly and to a similar extent to user pays.	Profits increased greatly and to a similar extent to consumer pays.
Wind	Profits decreased most.	Profits decreased moderately.	Profits decreased least.
PV	Profits decreased most.	Profits decreased moderately.	Profits decreased least.

6. Discussion and Conclusion

The results in section 5 highlight some key implications for the implementation of market-based incentives for the provision of inertia.

Firstly, the inertia market design and particularly the choice of cost-recovery mechanism strongly impact the achieved renewable energy penetration and costs to consumers. The *causer pays* market tended to reduce the total renewable energy penetration and may thus be poorly suited to a future version of the NEM with renewable energy penetrations in excess of ~60%. The *user pays* market led to the lowest total costs to consumers of any of the three inertia markets considered. Although the *user pays* market is a somewhat experimental concept, there appears to be value in further investigating market mechanisms which allocate costs according to NEM participants' relative requirement for FFR.

Secondly, there are potentially significant operational cost savings associated with installing synchronous condensers, relaxing RoCoF requirements or allowing synthetic inertia to be bid into inertia markets. Further research into the capabilities of a range of FFR technologies and a better understanding of their technical constraints is therefore critical to delivering affordable electricity to end users.

Thirdly, results indicate that the increased profits for coal and gas plants from inertia markets are significant at high renewable energy penetrations. This implies that such plants are of great value to the system when inertia is scarce. Since coal plants in particular are likely to have reduced energy production in the NEM in the future, the option of converting existing plant to synchronous condensers may be profitable for coal operators and efficient from a system perspective. The costs of conversion relative to the financial benefit is an important area of future work.

This study offers new insights into the use of market-based approaches with a dynamic inertia requirement for addressing the emerging frequency control challenges associated with falling inertia in the NEM. However, significant modelling limitations mean that the findings of this study should be interpreted with significant caution.

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