

# Operation of Ancillary Service Markets with Large Amounts of Wind Power

S. R. Thorncraft

[s.thorncraft@ieee.org](mailto:s.thorncraft@ieee.org)

H. R. Outhred

[h.outhred@unsw.edu.au](mailto:h.outhred@unsw.edu.au)

D. J. Clements

[d.clements@unsw.edu.au](mailto:d.clements@unsw.edu.au)

F. K. Barker

[filita@unsw.edu.au](mailto:filita@unsw.edu.au)

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Centre for Energy and Environmental Markets

The University of New South Wales, Sydney, Australia

## Abstract

High integration levels of wind energy in a restructured electricity industry will have implications for centralised and decentralised decision-making processes. This paper comments on the operation of the market-based ancillary services implemented in the Australian National Electricity Market (NEM) under such a scenario. The issues for decision-making processes are categorised into security, technical and commercial dimensions. The main focus of the paper is on security and technical related matters with commercial issues being considered in less detail. Conclusions are then drawn with a brief discussion of the features of the NEM that facilitate high levels of wind integration and aspects of its design that might be improved. In this way the NEM can be compared to market designs implemented elsewhere in terms of features that facilitate wind integration.

## 1. Introduction

Increased awareness of climate change, the implementation of environmental markets and the desire to reduce reliance on non-indigenous fuel sources has resulted in the integration and plans for further integration of significant amounts of wind power into electricity industries throughout the world [1], [13]. A high integration level of wind energy will to varying degrees impact all of the decision-making processes that are implemented in a restructured electricity industry with implications for both centralised and decentralised forms of decision-making [6].

A set of decision-making processes that may be impacted are those concerned with ancillary services. Ancillary services are control actions coordinated by the system operator and implemented by generators, consumers and network service providers to manage the availability and quality of supply [15]. In many electricity industries, market-based arrangements have been implemented for ancillary services [28], [29]. Consequently there is a need to consider not only technical issues but also the commercial implications for all market and industry participants.

This paper comments on the operation of the market-based ancillary service arrangements in the Australian National Electricity Market (NEM) for a high level of wind integration. The main focus of the paper is on security and technical related matters with commercial issues being considered in less detail. To this end, the market design features that facilitate wind power integration are identified as well as the aspects that may need refinement. In this way the NEM design can be compared to market designs implemented elsewhere in the world in terms of the features that facilitate the integration of wind resources.

## 2. Australia's Electricity Spot Market Arrangements

The NEM presently comprises the south-eastern states of Queensland, New South Wales, Victoria, South Australia (SA), Tasmania and the Australian Capital Territory and supplies around 90% of Australia's demand for electricity [27]. The electrical network spans a large area of approximately 4000km from north to south and 2000km from east to west. Assuming the feasibility of network augmentation to sites plentiful in wind resources the NEM could see a large amount of wind integration and is well placed to benefit from diverse weather conditions across its large geographical scope.

The NEM implements a regional gross-pool electricity spot market that is solved on a 5-minute cycle. In addition to pricing and dispatching energy services, the electricity spot market also prices and coordinates 8 different types of frequency control ancillary service (FCAS). While the system and market operator, NEMMCO<sup>1</sup>, implements several forward-looking processes to forecast the supply, demand and prices, only the ex-ante 5-minute regional energy and FCAS prices are used for spot market settlements. Participants also trade in electricity derivative markets to manage financial risks associated with electricity spot market outcomes.

Market generators are presently classified as being scheduled or non-scheduled. The former applies to generation systems that exceed a nameplate capacity of 30MW with such entities being allowed to submit offers for the provision of energy and FCAS. Presently the NEM classifies large wind farms, even those exceeding 30MW in size as being non-scheduled. Rule changes are presently being progressed that may introduce a third category, semi-scheduled that would apply to large intermittent generation sources such as wind [19], [20]. To facilitate participants in making

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<sup>1</sup> National Electricity Market Management Company

decentralised unit-commitment decisions, the bids and offers may be revised as required and can influence the next set of 5-minute prices and dispatch<sup>2</sup>.

## 2.1. Frequency control ancillary service arrangements

A detailed discussion of ancillary service arrangements in the NEM is given in [17] and the references within; this paper restricts attention to only the market-based FCAS. The 5-minute electricity spot market jointly dispatches generators (and controllable loads) for the provision (and consumption) of energy as well as setting aside generation capacity (and controllable load) to restore the balance between supply and demand within each 5-minute period by correcting both small and large deviations in measured power system frequency.

The key attributes of the 8 types of FCAS are summarised in Table 1. The services are defined in such a way as to accommodate a variety of technologies, thus there are different service response times as well as the notion of raise and lower services. The former are concerned with increasing generation (or reducing load) to correct the system frequency when it falls below nominal<sup>3</sup> and the latter with decreasing generation (or increasing load) to correct the system frequency when it rises above nominal.

Each market participant submits offers for any of the 8 services they are willing and able to provide and the electricity spot market optimisation computes the lowest cost service providers along with the corresponding FCAS prices. The generators (or controllable loads) participating in the FCAS markets are provided with *enablement* levels for each of the 8 FCAS which is a quantity of generation or controllable load set aside to correct frequency deviations, if required, over the next 5-minute period.

NEMMCO computes the total amount of each service required to satisfy the frequency standards [9] for each 5-minute electricity spot market period based on the present state of the system; these are termed the *FCAS requirements*. Under most circumstances FCAS providers can correct the frequency from anywhere within the interconnected power system, however situations arise where it is necessary to source (or “pre-arm”) FCAS providers from specific network locations. Accordingly, NEMMCO sets the FCAS requirements in terms of *global requirements* where providers may deliver a response from anywhere within the connected system and *local requirements* where providers must be situated at particular network locations.

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<sup>2</sup> In other words, there is no gate closure other than minor delays attributable to communications and the time it takes to solve the spot market optimisation which is of the order of seconds.

<sup>3</sup> The nominal frequency in Australia is 50Hz.

Generators (and controllable loads) that are enabled to provide FCAS earn spot market revenue for each service as follows<sup>4</sup>:

$$FR_{ij} = \frac{FP_j \times FE_{ij}}{12}$$

where  $i$  is an index for market participants,  $j$  is an index for each FCAS,  $FR_{ij}$  is the 5-minute revenue earned by participant  $i$  for being enabled for service  $j$ ,  $FP_j$  is the 5-minute price of service  $j$  and  $FE_{ij}$  is the 5-minute FCAS enablement level for service  $j$ . This payment is made irrespective of whether the service is required and no further payments such as usage payments are made.

Table 1. FCAS service definitions

Service Class	Service Name	Service Description
Regulation	Regulation raise	Continuous correction of small frequency deviations and accumulated time errors. The control action is implemented by a centralised Automatic Generation Control (AGC) system.
	Regulation lower	
Contingency	6-second raise	Fast acting response to arrest large frequency deviations within the first 6 seconds following a disturbance; for example governor response and under-frequency load shedding.
	6-second lower	
	60-second raise	Slower acting response to stabilize the frequency deviations within 60 seconds of the disturbance.
	60-second lower	
	5-minute raise	Response to return the system to a normal frequency operating band 5-minutes after the disturbance. For example, rapid unit unloading or loading.
	5-minute lower	

## 2.2. Ancillary service cost recovery

The total revenue that is paid to the FCAS providers is subsequently recovered from market participants according to the cost-recovery methodologies described in Table 2 [21].

The criterion on which a market participant is charged under causer pays for regulation services is based on the availability of adequate SCADA metering; this generally includes most of the large wind farms built to date in the NEM [33].

During FY 05/06, the FCAS costs totalled \$31m which is only 0.4% of the combined cost of FCAS and energy market turn-over. For this period, regulation services accounted for 15% of the FCAS costs; raise contingency services 48% and lower contingency services 37% [30].

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<sup>4</sup> For simplicity, the formula excludes notation to account for the fact that revenue is paid on a regional basis using regional FCAS prices.

Table 2. FCAS cost recovery methodology

Service Class	Service Name	Cost Recovery Method
Regulation	Regulation raise Regulation lower	Causer-pays methodology applies, which is a calculation based on 4-second SCADA measurements of generator outputs to identify the plant that caused the need for regulation and hence regulation costs are allocated accordingly.
Contingency	6-second raise 60-second raise 5-minute raise	Market generators charged in proportion to energy production. Costs arising from the need to source FCAS within a localised area are assigned to generators located in that area in proportion to energy production.
	6-second lower 60-second lower 5-minute lower	Market customers charged in proportion to energy consumption. Costs arising from the need to source FCAS within a localised area are assigned to consumers located in that area in proportion to energy production.

### 3. NEM Wind Integration

The NEM presently experiences a coincident peak demand of 32GW and has 42GW of installed capacity including a little over 600MW of wind power resources. If the integration level is defined as the total nameplate capacity of the wind resource divided by peak demand, then this corresponds to a 2% wind integration level. Table 3 shows that based on wind farms presently under construction, the integration level<sup>5</sup> will double to 4% and if all of the planned wind farms were built then it could rise to 12% [26]. An estimate of the total amount of wind resources that could be integrated into the NEM excluding issues associated with network limitations suggests that 8.4GW is feasible, which corresponds to an integration level of 26% [31].

Table 3. Wind integration scenarios in the Australian NEM

Status	Installed NEM Capacity (MW)	NEM Integration Level (%)
Built	618	2
Under construction	556	4
Planning approval	2752	12
Estimate of feasible integration	8400	26

High integration levels of wind will test the robustness of electricity markets and the corresponding arrangements for the management of system security of which ancillary services play an important role. This paper classifies electricity market design issues into the following three categories with the potential risks to FCAS being as follows [32]:

- *Security issues* are actions taken by the system operator to ensure the power system is operated within the frequency standards. These include the calculation of FCAS contingency

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<sup>5</sup> Excluding the possibility for a change in peak demand.

requirements, calculation of FCAS regulation requirements and assessing inter 5-minute ramping issues;

- *Technical issues* correspond to the decentralised physical operation of wind farms including the controllability of wind farms and their potential contribution to system frequency control; and
- *Commercial issues* comprise the financial implications of the FCAS markets, behaviour of market participants and their ability to participate in the FCAS markets.

The first of these issues will be discussed in detail in this paper with the latter two being treated in less detail.

## 4. Contingency Requirements

For each 5-minute spot market interval, NEMMCO calculates the FCAS contingency requirements for the 6 contingency FCAS described in Table 2 to be delivered by providers to replace the generation (or load) lost following an unplanned generator (or load) failure. The FCAS raise contingency requirements are based on the size of the largest potential loss of generation and the FCAS lower contingency requirements are based on the size of the largest potential loss of load<sup>6</sup>. Because network failures can result in the loss of generation or load they are also taken into account in the calculation. The specifics are detailed in [24] and [34].

Contingency requirements are also specified on a locational basis. A case that is particularly relevant for a high wind integration scenario is the setting of local contingency requirements for the state of Tasmania on the basis of power flows on the high voltage DC transmission line Basslink which connects Tasmania to mainland Australia as shown in Figure 1. The transmission line is unable to transfer FCAS between the mainland and Tasmania under certain conditions most notably when it reaches the maximum export limit or maximum import limit or when it is transferring power within a ‘dead-zone’ between -50MW to 50MW. This typically occurs whenever there is a transition from exporting power to importing power or vice-versa [23]. At times when Basslink is unable to transfer FCAS, the mainland and Tasmania must each be able to correct frequency disturbances using only resources within the respective regions. Tasmania is also a good candidate for further wind integration with 134MW presently installed, 74MW under construction and 290MW with planning approval.

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<sup>6</sup> An estimated amount of frequency-sensitive load is subtracted from the largest loss of generation or load.

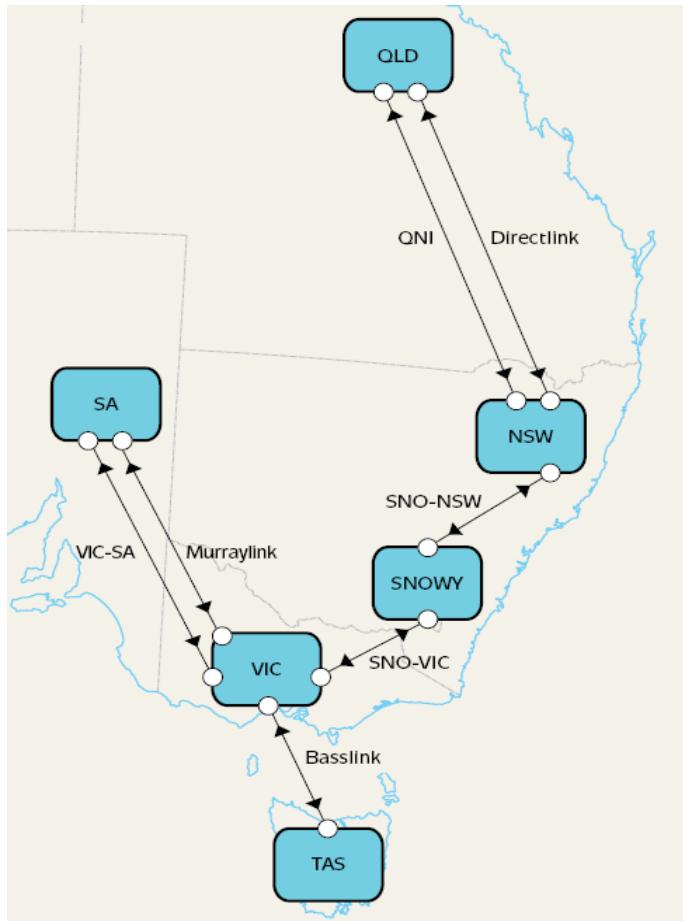


Figure 1. Diagram of NEM regions and south-eastern Australia

#### 4.1. Largest generator and load contingencies

Before considering the impact of wind integration on FCAS contingency requirements, it is useful to obtain insight into the present sizes of the largest credible contingencies. Duration curves for the largest estimated generation contingencies are shown in Figure 2 and for the largest estimated load contingencies in Figure 3 both for the period January 2006 to April 2007.

Each diagram has three curves as follows:

- the *interconnected* curve corresponds to the largest contingency while the NEM was connected and able to transfer FCAS between the mainland and Tasmania;
- the *mainland* curve corresponds to the largest contingency in the mainland at the times when the NEM was unable to transfer FCAS between the mainland and Tasmania; and
- the *Tasmania* curve corresponds to the largest contingency in Tasmania at the times when the NEM was unable to transfer FCAS between the mainland and Tasmania.

Over the period of the graphs, the NEM was interconnected for 74% of the time which is mostly attributable to Basslink first coming into service on 29 April 2006. Since Basslink has been in operation, it has been able to transfer FCAS around 94% of the time.

These diagrams suggest that at the times when the system was interconnected or when it was necessary for the mainland to source FCAS on its own; the output from a set of wind farms would need to fall by more than 500MW in less than 5-minutes before it would be necessary to increase the raise contingency requirements. Similarly, a set of wind farms would need to rise by more than 370MW in less than 5-minutes before an increase in lower contingency requirements would be necessary.

At the times when Tasmania is unable to rely on the delivery of FCAS from the mainland, the situation is more restrictive: a sudden decrease in wind farm outputs exceeding 110MW will generally exceed the size of the largest generator contingency. Similarly, a sudden increase in wind farm output of 120MW would generally exceed the size of the largest load.

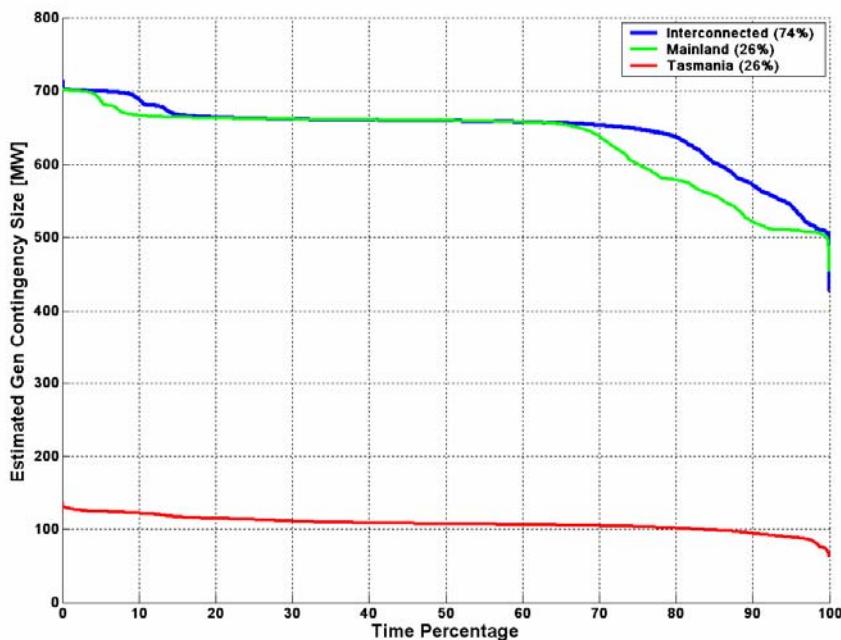


Figure 2. Duration curves of largest generation contingency for 3 situations

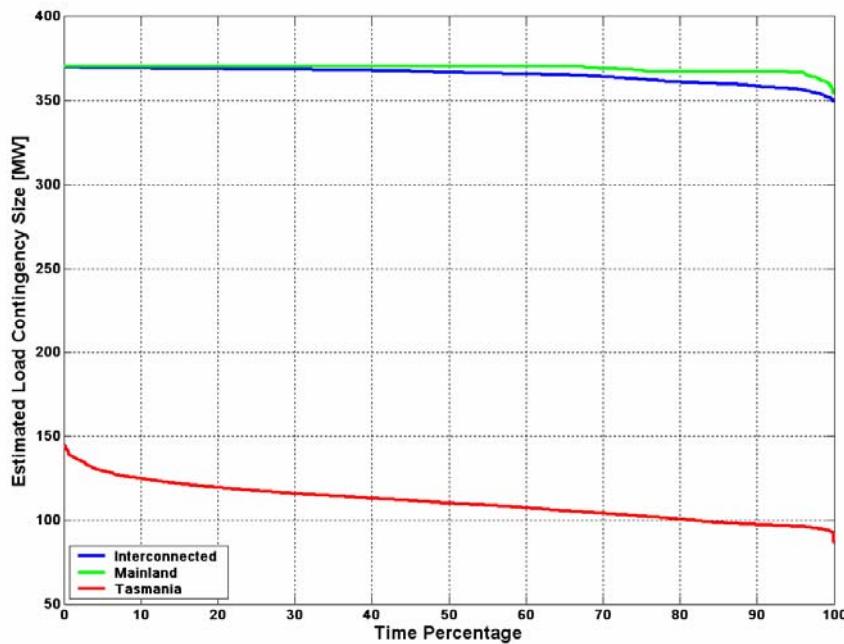


Figure 3. Duration curves of largest load contingency for 3 situations

#### 4.2. Contingency classification for wind farms

A contingency could be defined to be a rapid, uncontrolled change in supply or demand on a short timescale without a subsequent correction to the imbalance from the failed resource. For example, Figure 4 shows a conventional generator outage and its prompt return to service a little over an hour later. Because wind farms are composed of many individual turbines each presently with nameplate ratings between 1MW to 2MW, it is unlikely that the failure of a single turbine would ever be classified as a credible contingency. However, the set turbines within a wind farm or across a set of wind farms could under certain situations be highly correlated and may give rise to an overall fluctuation that poses a threat to system security. For example, Figure 5 illustrates the output of a wind farm in Tasmania which decreases rapidly as individual wind turbines are simultaneously shut down to prevent damage from high wind speeds (in this instance, the cut-off speed is  $25\text{ms}^{-1}$ ).

However, more generally the large fluctuations in wind farm outputs are harder to classify as contingencies and the question of how to unambiguously define a contingency for stochastic generation sources arises. For example Figure 6 shows the combined output of 5 NEM wind farms in SA where there is a significant fall in generation which on a larger scale may require deployment of raise services although the drop in generation is partially corrected itself. Similarly Figure 7 shows an overall increase in generation which on larger scale would require the deployment of lower services.

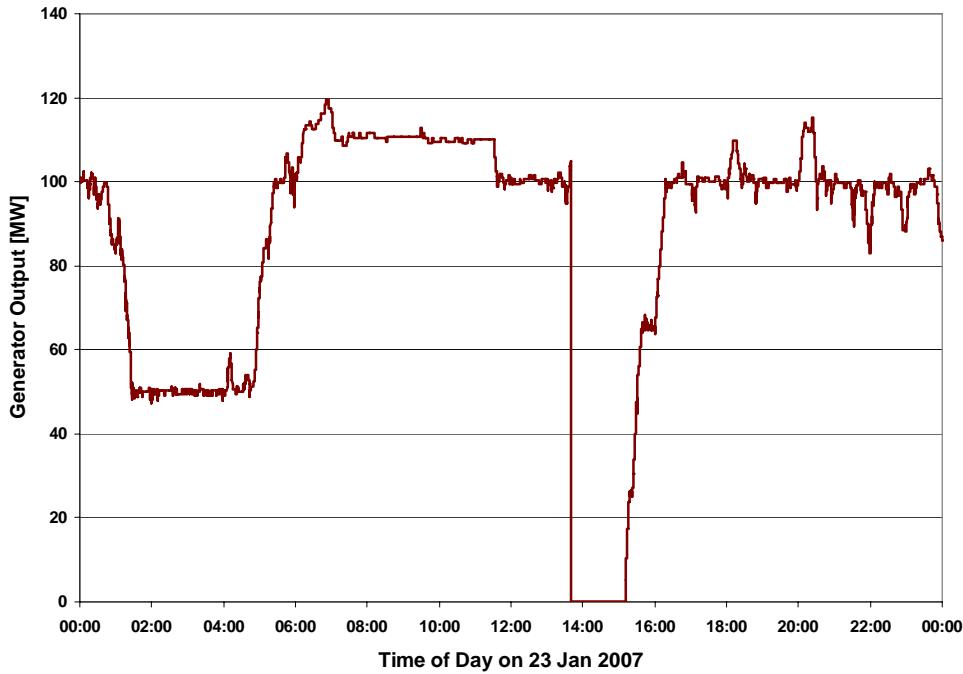


Figure 4. Conventional generator unplanned outage and return to service

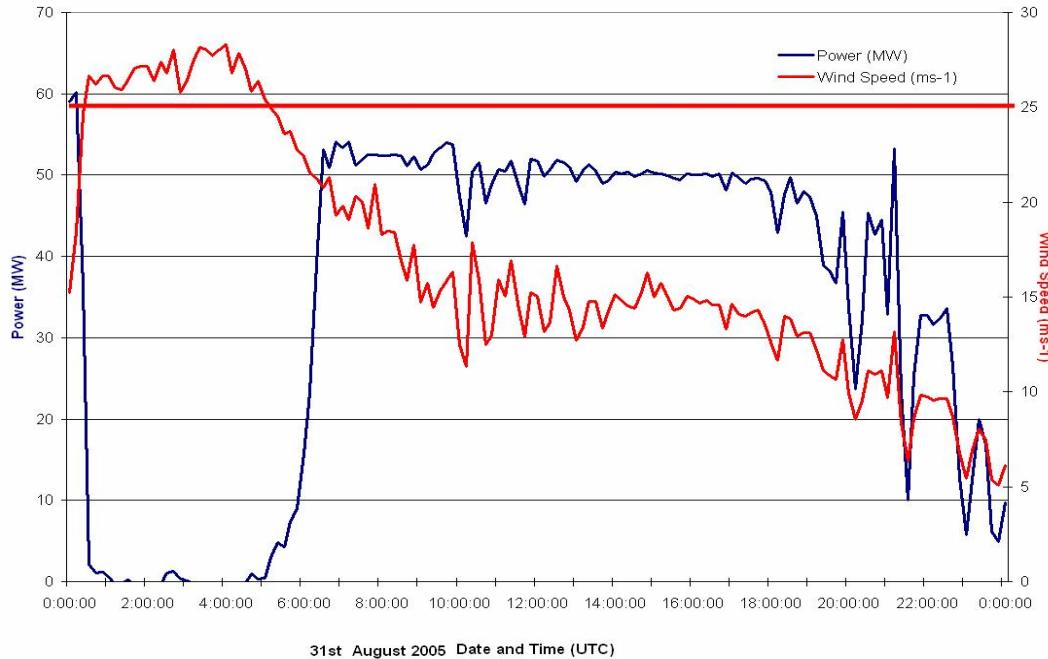


Figure 5. Output of Tasmanian wind farm and wind speed on 31 August 2005 [37]

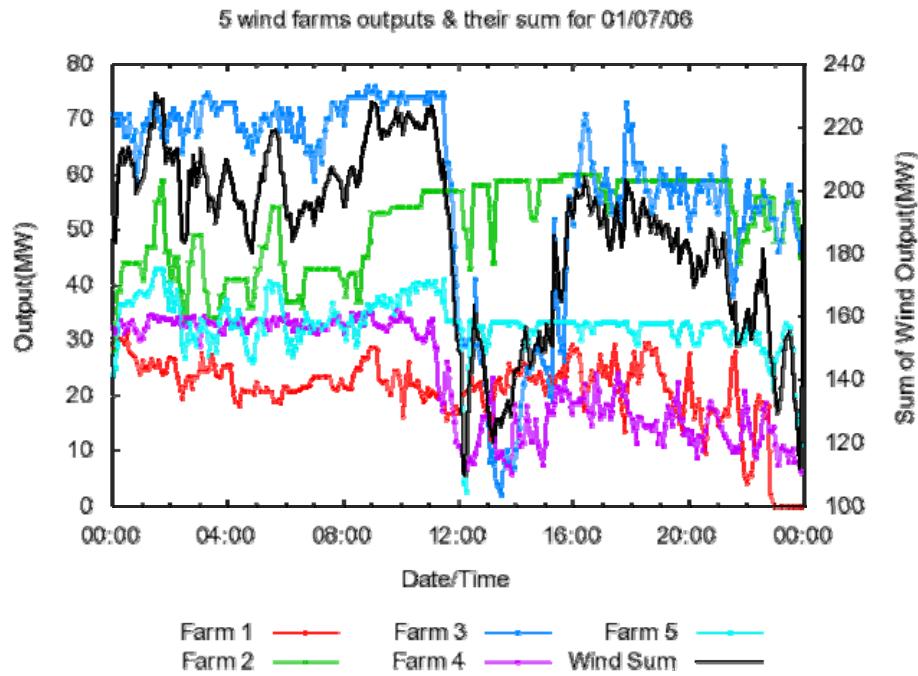


Figure 6. Combined output of 5 NEM wind farms with sudden generation decrease

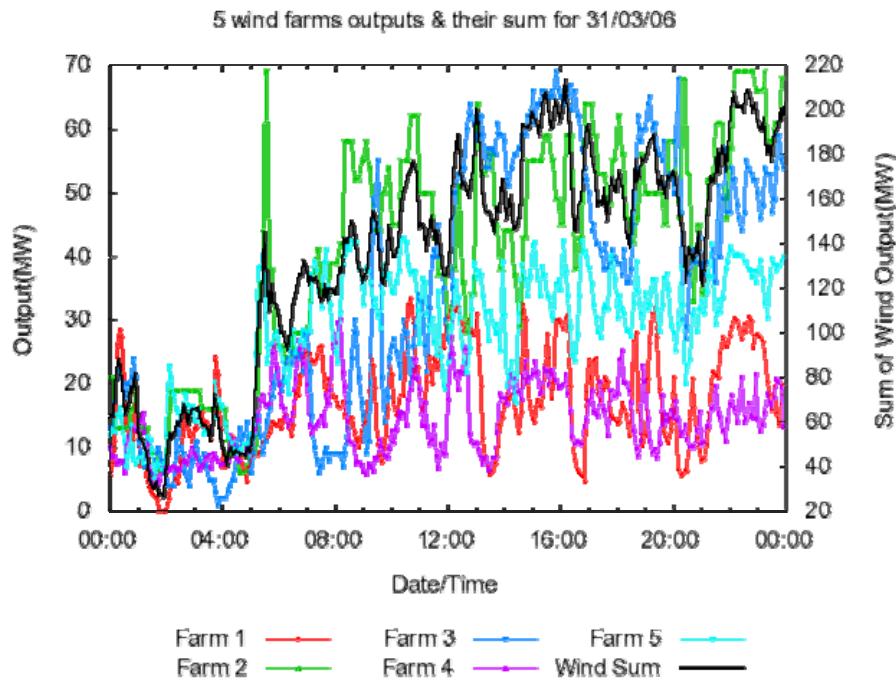


Figure 7. Combined output of 5 NEM wind farms with sudden generation increase

While these examples are unlikely to have resulted in significant frequency deviations, they highlight that a change in mindset is required for contingency analysis under a high wind integration scenario, including:

- the need to consider the correlated generation patterns across numerous wind farms rather than the output of the single largest wind farm; and
- the security risk may not be observable from measurements of the electrical equipment but rather from observations or a general understanding of weather conditions.

Consequently, for a high level of wind integration it may be necessary for system operators to adjust contingency requirements on the basis of wind speed measurements and forecasts, wind power measurements and forecasts and general observations of meteorological conditions. Preferably, any assessment of the conditions would be of an objective nature given that costs are associated with increases in contingency requirements.

### **4.3. Screening wind farm data for large deviations**

To establish some insight into the large fluctuations that a set of wind farms could produce, 10s SCADA measurements of the 5 wind farms<sup>7</sup> in the state of SA for the period of January to August 2006 (224 days) were analysed<sup>8</sup>. Taking a similar approach to that in [36], Figure 8 comprises the density functions of variations in outputs on timescales of 10s, 20s, 1m, 2m and 5m based on the 10s measurements of the combined output of 5 wind farms. The diagram shows that the vast majority of variations in wind farm outputs remain within 4% of the wind farm's installed capacity in either direction on these timescales. This illustrates that large variations in wind farm generation occur with low probabilities and it is therefore necessary to examine the tails of the distributions for large output deviations.

To examine the extreme deviations present in the data a set of extreme percentiles are shown in Figure 9. The percentiles of 0.0001% and 99.9999% account for 30m of 10s measurement, 0.01% and 99.99% account for 50 hours while 0.1% and 99.9% account for 22 days. The diagram suggests that fluctuations of around 10% in either direction can occur on timescales shorter than 60s while fluctuations in the range -20% to 25% are generally observed within a 5-minute period.

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<sup>7</sup> With a combined installed capacity of 318MW.

<sup>8</sup> Data provided by ElectraNet.

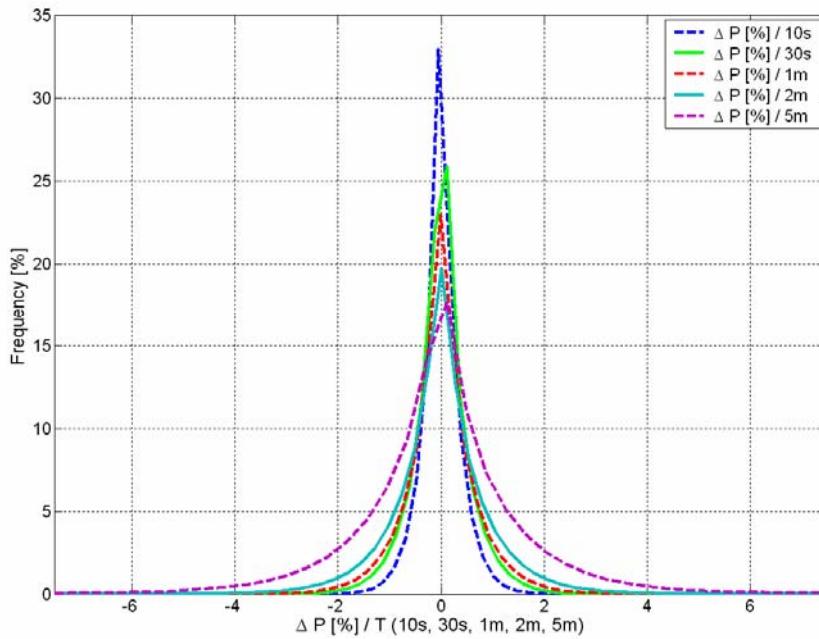


Figure 8. SA wind farm power output variations on different timescales (Jan-Aug 2006)

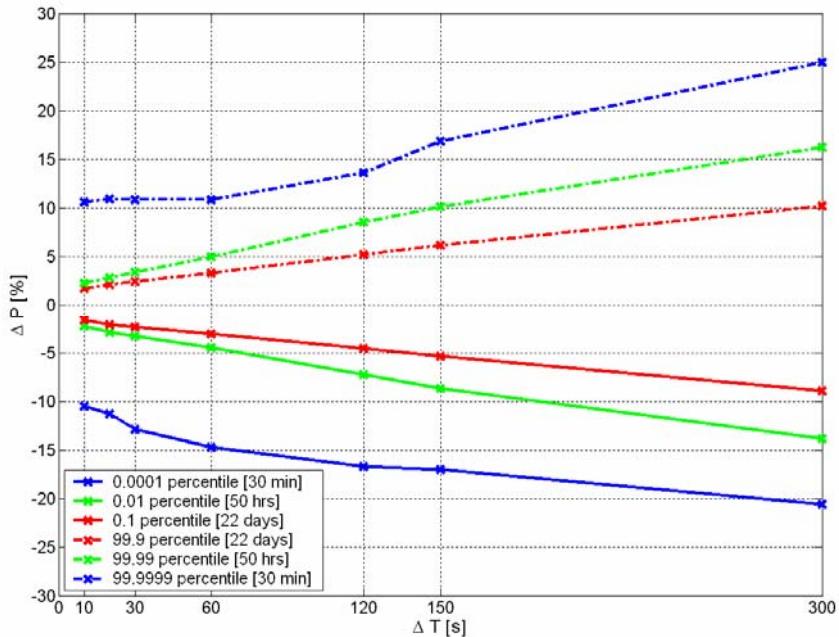


Figure 9. SA wind farm power output extreme variations for different timescales (Jan-Aug 2006)

Analysis of the data generally implies that large swings in the combined outputs of wind farms on short timescales are unlikely to impact raise or lower contingency requirements both for the present level of wind integration and for much higher levels. For example, simply scaling the results implies that a set of wind farms that simultaneously experience similar weather condition would need an installed capacity of 5000MW to produce output variations of 500MW / 10s before an increase in raise and lower contingency requirements beyond present levels would be necessary.

#### **4.4. Network connection issues**

Network planning has historically been concerned with conveying power from bulk suppliers to major load centres without regard for sites high in wind availability. In terms of contingency requirements, a reliable network connection to the grid will decrease the likelihood of a wind farm (or a set of wind farms) being classified as a credible contingency on the basis of network failure. Thus coordination between the planning of network augmentations and the planning of wind farms with regard to the implications for FCAS contingency requirements plays an important role in the management of security.

#### **4.5. Wind farm inertia**

A reduction in system inertia causes an increase in the rate of change in frequency following large contingencies and the effect may be worse when part of the connected system that with a high proportion of low-inertia resources synchronised to the grid becomes islanded [10]. Reference [22] examines the inertial response of SA under islanded conditions and suggests that for high wind integration the rate of change in frequency following the islanding of SA could increase by 40% to 55% depending on the load at the time. In the absence of sufficient contingency services to arrest the frequency either within an islanded region or across the system as a whole following a major contingency could result in frequency collapse. While modern wind turbines are fitted with power electronic interfaces to emulate an inertial response [11], [16], there are limits to the extent of the response and so a high wind integration scenario may require an increase in contingency reserve levels beyond present levels in order to account for the lack of inertia. It is more likely that the issue will first arise in locations that have a high concentration of wind resources and that are also at risk of being islanded rather than on a system-wide basis. Hence, locational contingency requirements are more likely to need to factor in the impacts of inertia rather than global requirements.

#### **4.6. Wind forecasting requirements and system operations for contingency FCAS**

Power system operations generally requires the consideration of high-impact low-probability events which are often difficult to forecast systematically because the events are non-stationary and have

ill-defined probability distributions. Thus the use of information such as wind speed measurements and knowledge of the potential generation at risk of being lost as a consequence of very high wind speeds could be factored into the process of setting FCAS contingency requirements. Since the NEM operates on a 5-minute cycle, short-term predictions of wind speed rather than wind power may prove to be more useful. This would also require wind farms to declare their turbine cut-off speeds to the system operator. Reference [38] outlines some of the difficulties inherent in short-term forecasting and suggests an approach for estimating wind speeds with reasonable accuracy on very short-timescales (2-3 minutes) with particular reference to Tasmania. System operations for contingency FCAS would also benefit from being able to identify the likelihood and implications of extreme fluctuations or oscillations in wind speeds and/or wind farm generation levels. This is presently an active area of wind forecasting research with recent results discussed in [4].

#### **4.7. Other risks to FCAS contingency requirements**

The analysis presented in this chapter implies that in the main, large scale wind integration in the NEM is unlikely to have a significant impact on the calculation of FCAS contingency requirements. However, the historical analysis of data alone is insufficient to completely quantify all operational risks or hazards that may be encountered, particularly in terms of identifying low probability events or events that may not have occurred to date. For instance, if the following conditions occurred simultaneously: Tasmania has wind integration level exceeding say 200MW, wind speeds in Tasmania are predicted to exceed shut-down thresholds of a significant number of wind turbines, the wind farms are generally operating near their nameplate ratings and Basslink is unable to import FCAS from the mainland; then the sudden shut-down of wind turbines across all wind farms will most likely constitute the largest credible contingency. The local contingency requirement for Tasmania should therefore reflect the wind farm generation that is at risk of suddenly being lost due to turbine shutdown. A similar risk arises when part of the NEM with a high amount of wind generation becomes electrically islanded from the remainder of the system, which occurs from time to time. Thus, with increased levels of wind integration there will always be a need to consider the implications of high-impact low-probability events and develop plans to reduce their impact or develop tools to assist in their detection.

### **5. Frequency Regulation Requirements**

Frequency regulation in the NEM is concerned with correcting small frequency deviations that arise from small errors in the 5-minute demand forecasts<sup>9</sup> and uncertain variations in scheduled generator

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<sup>9</sup> The demand forecast in the NEM is actually an estimate of demand less non-scheduled generation.

outputs, non-scheduled generator outputs and in demand. The raise and lower regulation requirements are set by NEMMCO as part of a monthly monitoring process where observations of the frequency and the accumulation of time-errors are made. Presently, the requirements are set so that (when the NEM operates as a connected whole) there is 130MW of raise and 120MW of lower except for certain periods<sup>10</sup> when the raise requirement is increased to 250MW to prevent time-error accumulation [18].

### 5.1. Present trends in frequency regulation

Figure 10 shows the daily profile of the Automatic Generation Control (AGC) system regulation requirement for different percentiles based on 4s measurements for the year 2006<sup>11</sup>. The regulation requirement is a control signal that is fed back to each generator that is required to provide raise or lower regulation FCAS. It reflects the amount of additional control effort that is required to correct the small frequency deviations. The key point of the diagram is to illustrate the times on average when the frequency regulation is most needed, in particular:

- early in the morning period between 4am to 8am there is usually a need for raise regulation which is coincident with the times when generators ramp to higher output levels to serve the day's load;
- during the day and into the evening the amount of regulation required is generally constant and slightly biased toward raise regulation; and
- the evenings experience some volatility in the regulation although there is usually a need for lower regulation.

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<sup>10</sup> Generally periods covering the morning ramping, afternoon peak and evening peak on business.

<sup>11</sup> Data source: NEMMCO, [www.nemmco.com.au](http://www.nemmco.com.au).

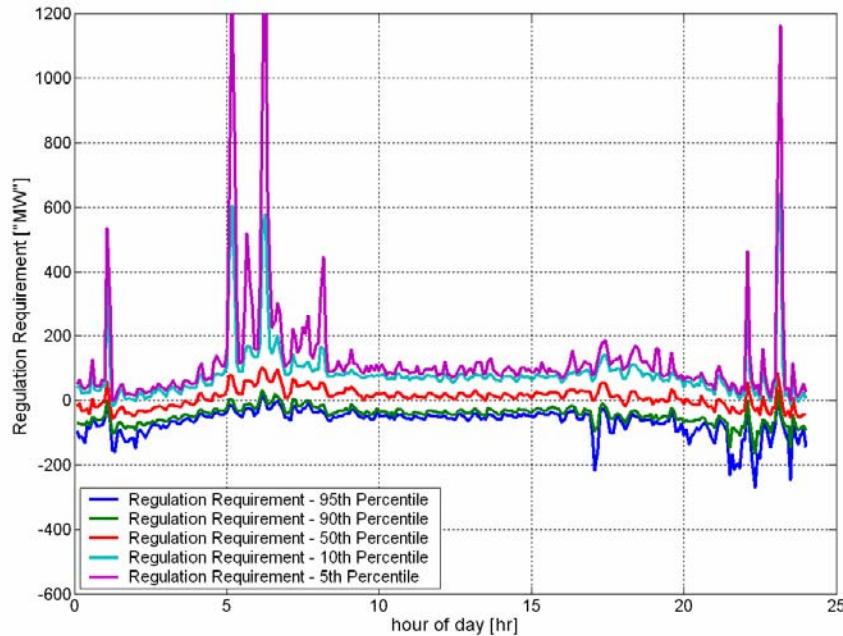


Figure 10. Regulation requirement daily profile in terms of percentiles for year 2006

## 5.2. Small deviations in wind farm generation

The question arises as to whether ongoing wind integration could exacerbate the need for regulation. To gain some insight into the behaviour of small deviations for wind across the day Figure 11 shows the density functions of the within 5-minute variations about lines of best fit applied for each wind farm in 5-minute blocks based on 10s SCADA data for the period January 2006 to August 2006. In this way, the lines of best fit act like “perfect 5-minute forecasts” and the variations comprise the small short-term deviations with any bias arising from an inaccurate forecast eliminated. The figure shows that the probability density functions of the variations for different 4-hour blocks of time over the course of a day do not vary significantly. Thus the data indicates that to date there has not been the emergence a systematic trend that might exacerbate the need for frequency regulation.

For the purpose of comparison, Figure 12 shows a base load generator based on 2 weeks of 4s data over January 2006. While the generator has a pattern that varies across the day with higher variations experienced over the evening, its overall variation are generally smaller than those attributable to wind farms. It is clear that the small deviations of the base load generator conform more closely to a normal (Gaussian) distribution while those of the wind farms have longer tails and appear to conform more closely to symmetric Levy distributions.

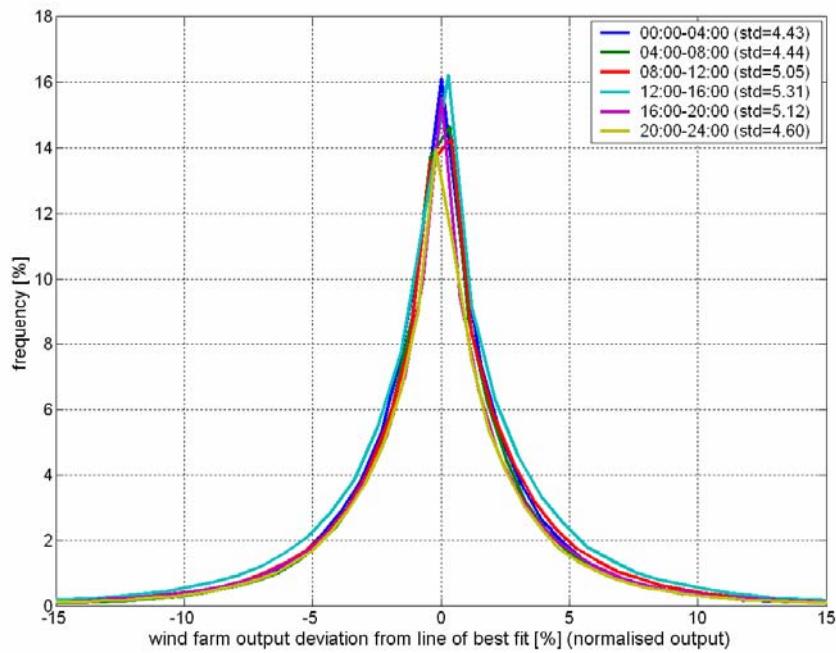


Figure 11. SA wind farm deviations from 5-minute lines of best fit (Jan-Aug 2006)

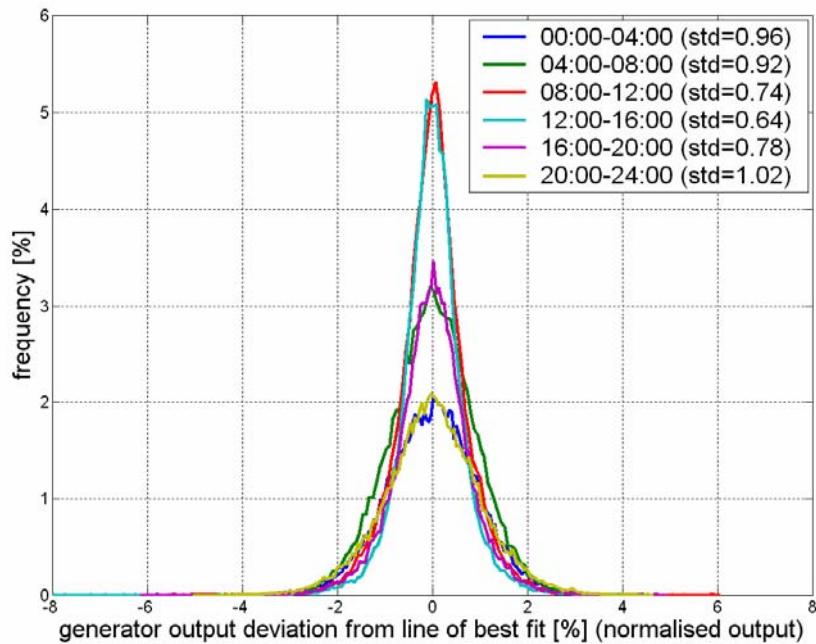


Figure 12. Example of deviations from 5-minute lines of best fit for base load generator

### 5.3. Observations of variability as a function of the number of wind farms

As reported in [2], [5], [7] and [8] increased levels of wind integration sees a reduction in the variability of outputs. A reduction in the overall variability in generation reduces the need for frequency regulation. The same trend can be demonstrated using 10s SCADA data for 5 SA wind farms. Figure 13 shows that the average standard deviation of the variability in the wind farms outputs decrease as the number of wind farms increases. Consequently increased levels of wind integration should reduce the impact on the need for frequency regulation.

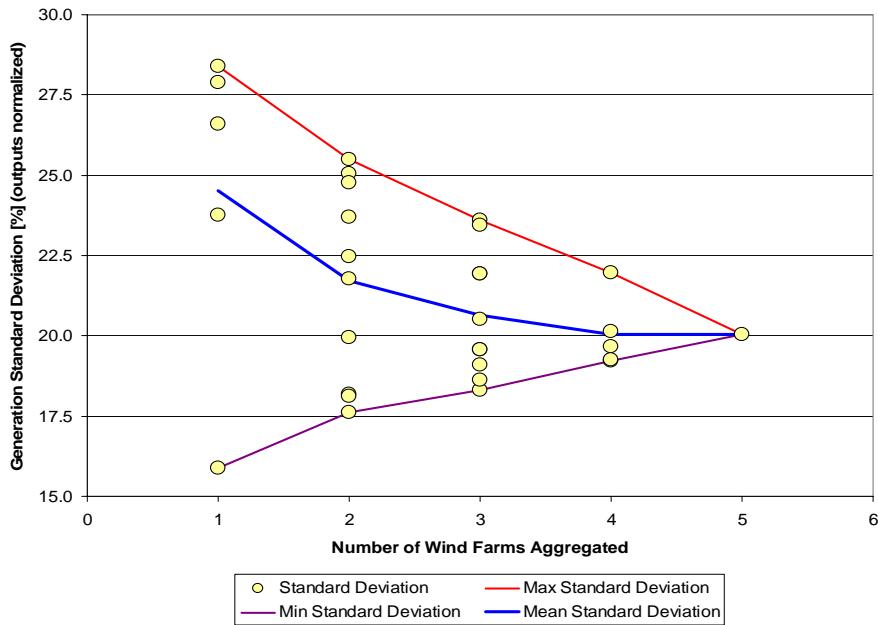


Figure 13. SA generation standard deviations for combinations of different wind farms (Jan-Aug 2006)

### 5.4. Wind forecasting requirements to assist frequency regulation

Another important aspect of minimising the impact of wind farms on frequency regulation is an accurate 5-minute-ahead forecast of generation. While there are many issues that impact the accuracy of wind forecasts and numerous ways of evaluating wind forecast accuracy, the following trends are observed: reductions in forecasting errors with reduction in forecast horizon, for example [14] suggests around a 5%-6% mean absolute error for 1 hour ahead compared to 15%-25% for 5 hours ahead for a variety of wind power forecasting techniques; and reductions in forecasting errors with the number of wind turbines that are aggregated, for example [12] suggests that broadly wind forecasting errors for regions tend to be more accurate than for individual sites. The 5-minute spot market interval in the NEM and its regional structure enable it to take advantage of these trends. However, while a regional (or a system-wide) wind power forecasts may reduce the need for

frequency regulation it is likely that large wind farms will in one form or another [19], [20] will be scheduled and hence forecast individually in order to facilitate decentralised commercial decision-making. Thus there may be a reduction in the accuracy of the forecasts. Consequently there is a trade-off between security management and facilitation of commercial decision-making. It is therefore important to ensure that the design of the electricity market imposes an incentive for accurate forecasts irrespective of whether the forecasting agent is centralised or decentralised.

## 6. Inter 5-minute Variations

The 8 FCAS are concerned with managing issues that arise within any given 5-minute period while shifts in supply or demand beyond a 5-minute period are solved as part of the electricity spot market. Thus the issue of load-tracking (which is sometimes treated in other industries as an ancillary service) has a technical dimension as well as a commercial dimension where market participants will respond to both price and dispatch outcomes. This section discusses the former issue while discussion of commercial decision-making is presented in section 8.

Figure 14 shows the NEM-wide ramping up and down daily profiles for the 5<sup>th</sup> and 10<sup>th</sup> percentiles based on the 5-minute data for the year 2006 where adjustments have been made for generator availability, minimum stable levels and maximum outputs of the plant. In essence the graph shows that (ignoring network limits) the NEM could collectively ramp down by 1500MW within 5-minutes or up by 3000MW within 5-minutes. Figure 15 shows the situation in Tasmania while Figure 16 shows the situation in SA where the graphs exclude generation capability that could be imported from neighbouring regions. The graphs show that the situation within those regions is more restrictive, with the following issues being evident:

- between 6-8pm<sup>12</sup> Tasmania's ramping up capability is a limiting factor and in the absence of imports for 5% of the time is unable to increase generation at a rate exceeding 40MW/5m – thus an increase in wind at a rate exceeding 40MW/5m could, in the absence of imports present a problem – a similar issue occurs for the period 8-10am where the ramping limit is more like 100MW/5m; and
- between 2:00-6:00 SA's 5-minute ramp down capability is around 70MW/5m which again, in the absence of imports indicates that there is a problem for around 5% of the time.

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<sup>12</sup> All time here is in Eastern Standard Time.

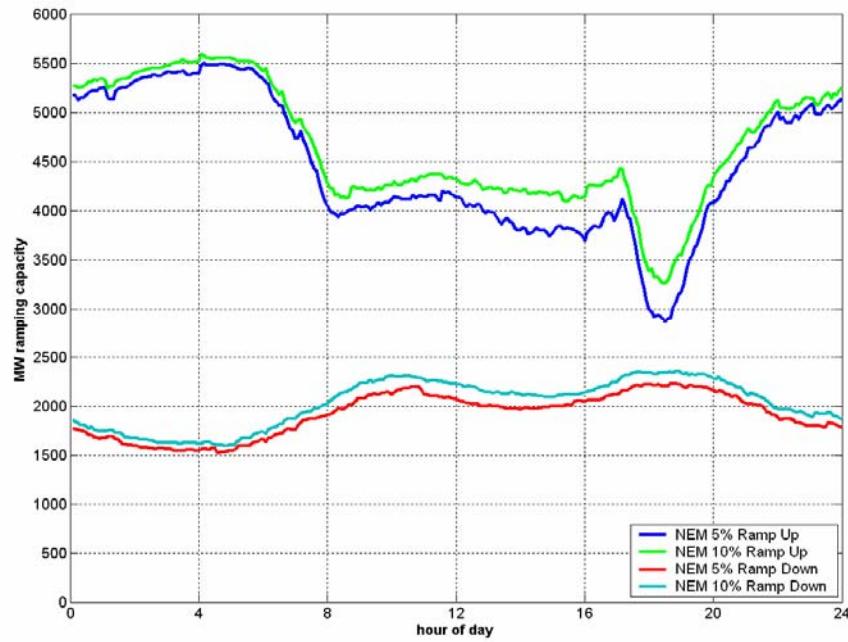


Figure 14. NEM-wide 5-minute ramping capability daily profiles for 5<sup>th</sup> & 10<sup>th</sup> percentiles for year 2006

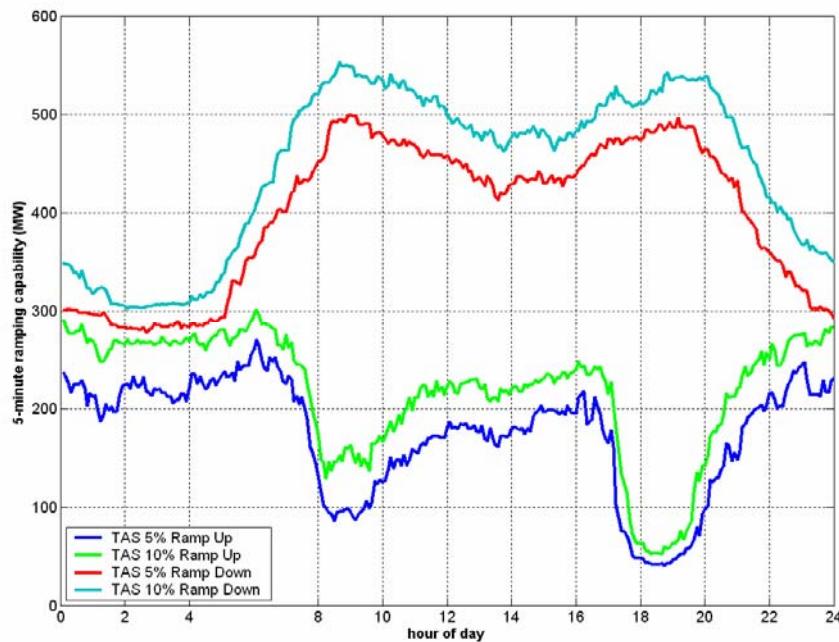


Figure 15. Tasmania 5-minute ramping capability daily profiles for 5<sup>th</sup> & 10<sup>th</sup> percentiles for year 2006

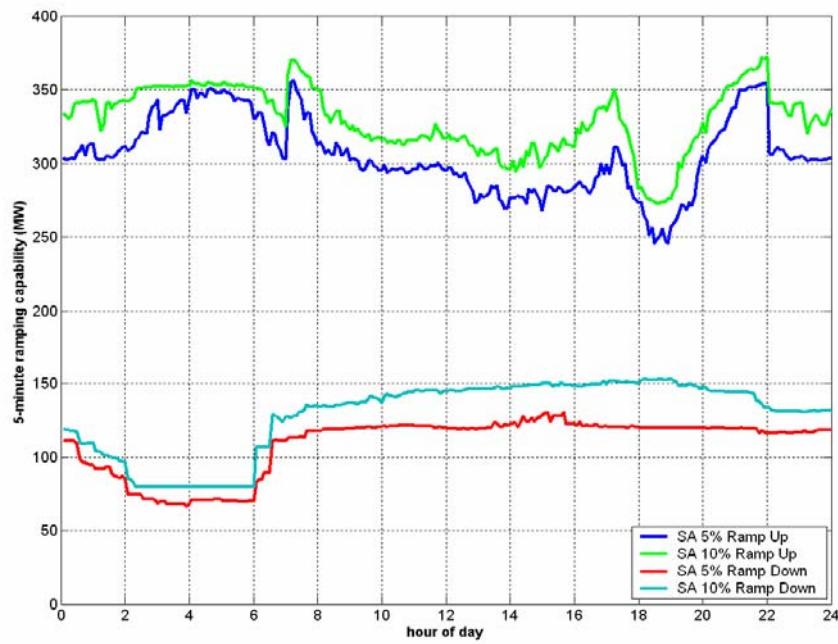


Figure 16. SA 5-minute ramping capability daily profiles for 5<sup>th</sup> & 10<sup>th</sup> percentiles for year 2006

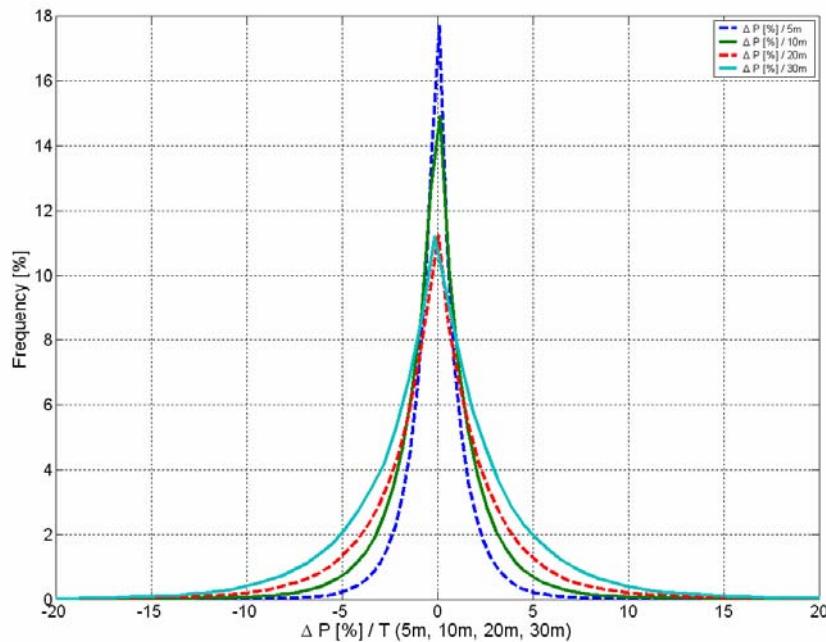


Figure 17. Distribution of changes in output for 5-minutes and other timescales of SA wind farms

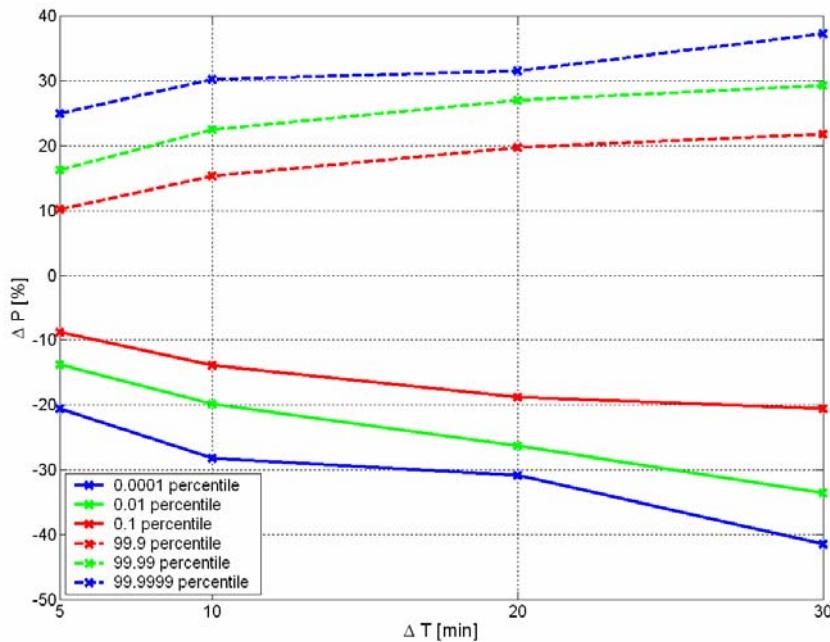


Figure 18. SA wind farm extreme variations in output for 5-minutes and other timescales

Comparing these observations to the distributions of wind farm deviations on different timescales plotted in Figure 17, we see that wind farm output fluctuations for the majority of the time are between -5% and 5% which should not pose a serious technical risk. The diagram shows that longer timescales exhibit larger overall fluctuations. The tails of the distributions are examined in a similar way as for the large within 5-minute fluctuations with the same extreme percentiles plotted as function of the timescale in Figure 18. This shows that extreme fluctuations on the 5-minute timescale are observed to be -25% to 20%.

If the results are simply scaled in terms wind farm capacity, the implication is that around 160MW of wind power in Tasmania may with low probability give rise ramping problems and similarly 280MW of wind power in SA may give rise to ramping issues. It should be noted that SA already has more than 280MW of wind generation installed (388MW) and to date problems haven't been reported possibly as a consequence of the analysis not accounting for power imported from adjacent regions or the low-probabilities associated with the occurrence of the event.

## 7. Wind Farm Control Capability for Provision of FCAS

From a technical perspective, a wind farm could be configured to operate in modes that would enable the provision of some of the frequency control ancillary services. References [3], [35] discuss the control capability of wind farms and identify the following control modes:

- *Balancing control mode* enables a wind farm to generate below its potential and exercise a degree of control over its specific generation level. In principle, a wind farm could receive raise and lower targets from the AGC to provide frequency regulation services in this mode – in order to provide raise regulation it would be necessary for the wind farm to spill an amount of power equal to its raise enablement and it would need to generate in excess of its lower enablement level;
- *Delta control* ensures that the wind farm spills an amount of power that remains constant. If the wind farm control system could be configured to utilise all of the energy that is being spilled based on frequency measurements in line with the FCAS response timescales (6s, 60s and 5m) then it would be possible for the wind farm to deliver raise contingency services. Furthermore, transitions from a normal operating mode into the delta control mode would enable the wind farm to deliver lower contingency services;
- *Power limited* mode where an upper bound on the output generation of a wind farm is enforced. While there is not a specific ancillary service that could leverage this capability, it has been cited as being useful in the management of network security issues [19], [20]; and
- *Ramp rate limited* mode of operation is when variations in a wind farm's output does not exceed a given ramp rate limit. While an ancillary services market for ramping does not exist, it may be a useful option for system operators to direct a wind farm to only ramp within limits in order to assist in management of security, for example if the issue identified in section 6 becomes material, then ramping limits could be imposed on wind farms at times when the issue will have a material impact on power system operations. Another area where ramp rate limited control could play a role is following the onset of wind speeds exceeding cut-off thresholds. If a ramp down limit could be imposed, then classification as a credible contingency may be avoided.

Figure 19 illustrates the control modes. Reference [35] indicates that all of these control options are all implemented by an offshore 160MW wind farm in Denmark, Horns Rev. Figure 20 illustrates how in principle the delta control mode can be adapted for the delivery of raise and lower contingency services.

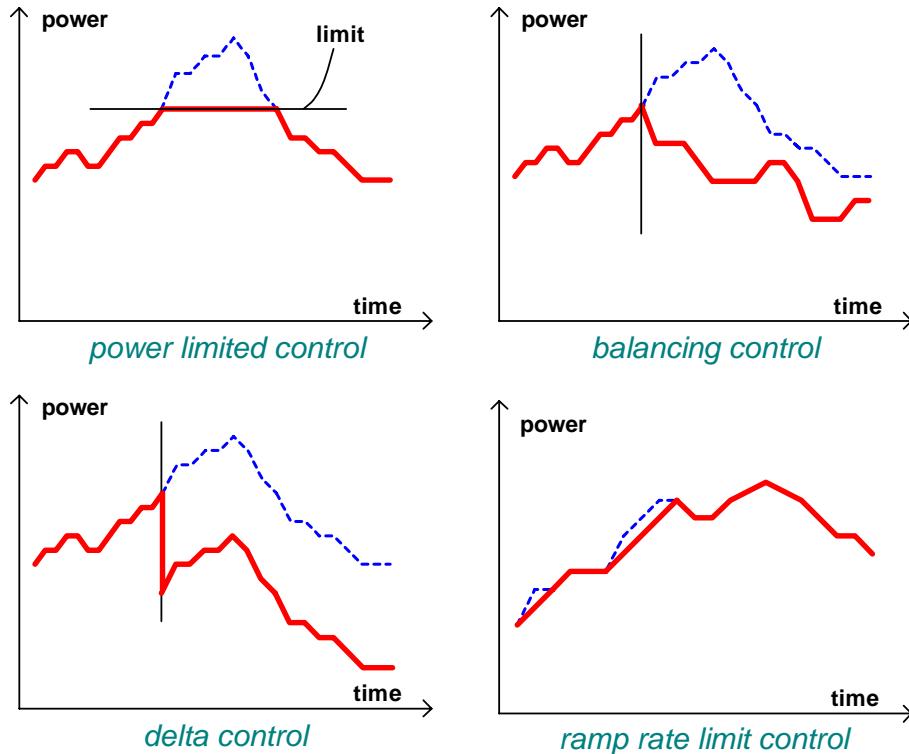


Figure 19. Wind farm control modes based on [35]

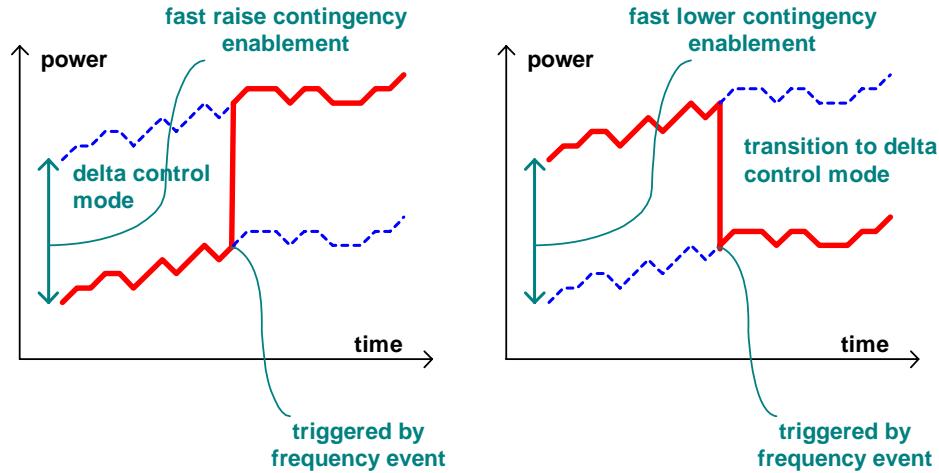


Figure 20. Example of fast raise and fast lower contingency service provision using delta control

Given that the control modes have been implemented in wind farms already then this suggests that it would be technically feasible for wind farms to be able to contribute to frequency control in the NEM and thus participate in the FCAS markets. The economic benefits of doing so would obviously need to be evaluated.

## 8. Commercial Issues

### 8.1. Wind farm participation in energy and FCAS markets

As discussed, a wind farm can be fitted with a control system that enables it to exercise a degree of control over the power it generates. In principle the control system would be configured to enable the wind farm deliver at least some of the frequency control ancillary services. The present arrangements in the NEM treat wind farms as being non-scheduled resources and they presently do not explicitly participate in energy or FCAS markets. However, a rule change consultation process has commenced which is likely to result in significant wind farms<sup>13</sup> being required to participate in the pricing and dispatch process [19], [20]. Consequently, wind farm operators would trade in the energy market and optionally any of the 8 FCAS markets in a way that is similar to a conventional generator.

The analysis presented earlier showed that the variations in the output of a 5 wind farms on a 5-minute timescale is around 5% of the nameplate capacity most of the time. With sufficient real-time information on wind speeds and short-term power forecasts, this degree of uncertainty could be managed by a wind farm spot trader by leveraging the fact that energy and FCAS offers may be updated<sup>14</sup> as required. Thus the existing market interface and operation of the NEM do not present a barrier to wind farm participation in energy and FCAS markets. The benefits of participation in FCAS would need to be traded against the costs associated with installation of the necessary control systems and the expected revenue streams between FCAS and energy.

### 8.2. FCAS prices

Factors that influence FCAS prices include the number of providers that make competitive offers for provision of the services and the FCAS requirements set by NEMMCO to satisfy the frequency standards. This paper suggests that except for low-probability situations, the FCAS requirements are unlikely to increase significantly under a high wind integration scenario. Thus, the key factor likely to influence the FCAS prices is the extent to which existing FCAS providers will be displaced by large scale wind integration. Table 1 shows that the FCAS providers have generally been spread across different technologies with gas and oil based resources having the smallest (albeit non-zero) share of these markets. This suggests that irrespective of changes to the merit order, the technical capability for service provision will generally be available from NEM participants.

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<sup>13</sup> A significant wind farm is one with an overall nameplate capacity of 30MW or higher.

<sup>14</sup> It is more accurate to say that only the offered quantities of FCAS and energy are modified in real time while the corresponding offer prices must remain fixed throughout the trading day.

If a significant shortfall in suppliers of the services results from a high wind integration level, then it will almost certainly be accompanied by an increase in FCAS prices which in turn provides incentives to players without the necessary control infrastructure to install the required hardware and participate in the FCAS markets. While a more comprehensive study of FCAS prices is required to completely understand all of the issues, it is suggested that the NEM can support a large amount of wind without a significant increase in FCAS prices. However it is important to also recognise that on influencing factor on FCAS prices that is difficult to predict is the occurrence of rare events that lead to very high FCAS prices and hence contribute to a significant proportion of the FCAS costs. Predicting the occurrence of such infrequent events is inherently difficult and outside the scope of this paper.

Table 4. Average NEM FCAS enablement (expressed as percentages) for year 2006

<b>Generator fuel source</b>	<b>Raise regulation average enablement (%)</b>	<b>Lower regulation average enablement (%)</b>	<b>Raise contingency average enablement (%)</b>	<b>Lower contingency average enablement (%)</b>
Black Coal	45%	38%	43%	43%
Brown Coal	19%	9%	16%	16%
Hydro	31%	45%	36%	36%
Gas / Oil	5%	8%	6%	6%

### **8.3. FCAS cost implications for wind farms**

The implications for a wind farm operating under the present cost-recovery arrangements for FCAS in the NEM is summarised in Table 5. This shows that like other generators in the NEM, a wind farm will not pay for lower contingency services while for raise contingency services the wind farm will be charged a portion of regulation costs in line with its fraction of energy production. For regulation services, a causer pays algorithm [25] that assesses the generators (and loads) that gives rise to the need for frequency regulation by processing 4s SCADA data is implemented. For a wind farm, this is based on correlations calculated over a 4-week period with the frequency regulation signal and the residuals from 5-minute lines of best fit while for a scheduled generator the residuals are computed as the difference between 5-minute linear spot market targets and actual 4s generation.

The analysis presented earlier in this paper suggests that the probability distributions of the 5-minute residuals for a set of wind farms is generally symmetrical and doesn't vary across the course of a day. While detailed analysis would be required to examine the full implications for a wind farm, the observations suggest that there is unlikely to be a strong positive or negative correlation with the regulation requirement, hence wind farms are unlikely incur large financial penalties because instances of positive correlation will be cancelled out by instances of negative correlation. Furthermore, the impact will be reduced for larger wind farms as they will experience less variability in energy production.

Table 5. FCAS cost recovery implications for a wind farm in the NEM

<b>Service Class</b>	<b>Service Name</b>	<b>Cost Recovery Implication for wind farm</b>
Regulation	Regulation raise Regulation lower	Causer-pays methodology applies.
Contingency	6-second raise 60-second raise 5-minute raise	A wind farm would be charged in proportion to energy production.
	6-second lower 60-second lower 5-minute lower	A wind farm would not pay for lower contingency services.

## 9. Conclusions

This paper has commented on a wide range of issues associated with the operation of ancillary service markets for a large amount of wind integration in the Australian NEM. To that end, the paper considered issues across security, technical and commercial decision-making regimes with the main emphasis on security as it pertains to system frequency. The security issues can generally be classified into two regimes: system normal (occurring most of the time) and rare-events. The data analysis suggests that system normal conditions are unlikely to pose significant challenges in the management of frequency control ancillary services in the NEM even for high levels of wind integration. Under such conditions, it is unlikely that there will be significant changes in the FCAS requirements and FCAS prices; hence FCAS costs are unlikely to increase while ever the system operates in a system-normal state.

However, it is always necessary to assess the potential security implications of rare events. Rare events while occurring infrequently have historically contributed to a significant amount of the costs associated with FCAS and are typically the result of an unexpected sequence of physical events that may not have been readily predicted. Nevertheless, a significant and necessary part of security analysis is the ongoing process of identifying risks and planning actions that could be taken by system operators in order reduce their likelihood of occurrence or to minimize their physical and commercial impacts on the system, should they occur. To this end, the paper has identified some situations where the system may be vulnerable and has suggested that system operations will benefit from access to information on the appropriate meteorological conditions, short-term predictions of wind speeds and the ability to pre-empt and respond to extreme events. Thus the expansion of the role of system operator to be able to assess these conditions, objectively determine their impact on the power system and take actions to adjust FCAS requirements will benefit the operation of NEM.

The features of the NEM that will assist in the uptake of wind include the use of a 5-minute market dispatch cycle and the ability for decentralized commercial participants to adjust their offers almost in real-time. The 5-minute dispatch cycle enables the use of accurate wind power predictions which

should enable wind farms to be dispatched in the centralized dispatch and pricing process with reduced uncertainty compared to a longer dispatch cycle. It also enables measurements of the system state to be reflected in the optimization model which also reduces model uncertainty, thus improving the accuracy of both pricing and dispatch outcomes. The fact that energy and FCAS offers may be revised by participants as required for almost certain inclusion in the next set of 5-minute pricing and dispatch outcomes provides participants trading portfolios with wind farms with a degree of flexibility; spot trading strategies can be adapted to the conditions as they unfold and relatively accurate 5-minute wind forecasts can leveraged.

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