Frequency Control Ancillary Services

Is Australia a Model Market for Renewable Integration?

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***Abstract*—Aspects of Frequency Control Ancillary Services (FCAS) in the Australian National Electricity Market (NEM) are discussed. Several aspects are identified as being relatively unique and beneficial for the integration of large quantities of variable renewables. These include fully dynamic setting of regulation reserves based upon real-time measurement of the time error, a sophisticated 'causer pays' mechanism for recovery of regulation costs, and a primary frequency response market that requires full response within six seconds. These aspects of FCAS in the Australian NEM may be able to serve as an effective model for other markets seeking to integrate higher quantities of variable renewables.**

Keywords-Frequency Control Ancillary Services

I. Introduction

Frequency Control Ancillary Services (FCAS) are those services required by a power system operator to ensure short-term supply and demand balancing throughout a power system. This requires precise control of system frequency through operational reserves that can respond to disturbances. FCAS are characterized differently in different electricity industry arrangements, depending upon the types of power system events they respond to, the timeframe over which they respond, the manner in which they are activated and whether they act to raise or lower the power system frequency. [1] provides a comprehensive and accessible summary of the definition of various reserve services in different international electricity markets, with other reviews being provided in [2, 3, 4, 5]. In this paper we refer to contingency reserves which respond to the sudden outage of a major generator, load or network element, and regulation reserves which operate continuously to manage ongoing variability and uncertainty within operational dispatch intervals.

Variable renewable technologies such as wind and solar photovoltaics (PV) will affect FCAS in a range of ways. Firstly, at high penetrations the variability and uncertainty of wind and PV will exceed the variability and uncertainty of demand, increasing the regulation reserve requirement [6, 7, 8]. This is one of the most important contributors to the 'system management costs' of variable renewables, and could be significant in some markets [9]. However, good market design can minimize the additional cost. Fast markets (with short dispatch intervals and short delays from gate closure to dispatch) operating over large balancing areas will tend to minimize regulation requirements [9].

Variable renewables are also typically connected to the grid through power inverters or non-synchronous generators that do not contribute inertia to the system. The system inertia provided by the large synchronous generators of conventional large plant slows the rate of frequency change under disturbances, and is particularly important in the event of a large generator outage, to ensure sufficient time for reserves to respond.

By displacing synchronous generation, variable renewables can therefore act to decrease overall system inertia. This is of particular relevance to the provision of primary frequency response (the very fast, autonomous response typically provided by the governors of thermal units). At present, most markets do not have any explicit provisions for incentivizing or mandating the provision of either inertia or very fast primary frequency response, anticipating that these services will be provided by thermal units connected to the system [10].

The FCAS market in the Australian National Electricity Market (NEM) appears to have been implemented successfully. The competitive spot markets for FCAS were implemented in September 2011, at which time the average cost of regulation fell immediately by approximately one third. Over the following 18 months, average procurement costs fell further by around 50%, an overall reduction from the introduction of the new market arrangements of around two thirds. Between July 2003 and August 2005, frequency regulation requirements were progressively reduced from 250 MW to 130 MW, with average procurement costs over that period also falling [11].

This paper explores various aspects of the FCAS market in the NEM, and examines whether the detailed implementation of these aspects may be able to inform other markets seeking to integrate higher quantities of variable renewables whilst minimizing integration cost related to FCAS.

A brief introduction to the NEM is provided in section II, followed by an overview of FCAS in the NEM in section III. The paper then explores more deeply several aspects of FCAS in the NEM which are identified as being relatively unique, and are proposed to be beneficial for the integration of large quantities of variable renewables. These include:

- ***Dynamic reserve setting*** – fully dynamic determination of regulation reserves based upon real-time measurement of the time error (section IV),
- ***Causer pays payment recovery*** – a sophisticated 'causer pays' mechanism for recovery of regulation payments (section V), and

– ***Primary Frequency Response market*** – a fast primary frequency response market that requires full response within six seconds (section VI).

Finally, various aspects of NEM FCAS market design could be adjusted in future to better manage increasing penetration of variable renewables. These are summarized in section VIII.

II. The Australian National Electricity Market

The NEM spans the east coast of Australia, supplying around 75% of the electrical load in Australia. It serves a peak demand of ~35 GW (2010-11) [12] and energy consumption of ~190 TWh pa (2012-13) [13]. Due to the large distances involved, there are no electrical connections between the NEM and any other markets.

The NEM is a gross pool, energy-only market, with a very high Market Price Cap of $12,900/MWh. Compared with many international markets, there are relatively few restrictions placed on the offers of market participants. Exercise of transient market power is recognized as an important aspect of NEM design to avoid the 'missing money' problem [14].

Marginal prices are applied regionally, in five regions corresponding to state boundaries.

The NEM is a single platform market, with only a single five minute (real-time) market. There is no day-ahead market; instead, market participants manage their own unit commitment, with the assistance of pre-dispatch forecasts provided by the Australian Energy Market Operator (AEMO). Market participants may re-offer their capacity at any time until immediately before the relevant five minute dispatch interval [15].

III. Overview of FCAS in the NEM

There are currently eight separate real-time spot markets for the delivery of FCAS in the NEM. Two are for the delivery of regulation (Regulation Raise and Regulation Lower), and six are for the delivery of contingency services (Raise and Lower for 6 second, 60 second and 5 minute response times). In aggregate, market participants offering contingency services are required to perform the following tasks [16, 17]:

– ***6 second*** – arrest a rapid change in system frequency within the first six seconds of a frequency disturbance, and then provide an orderly transition to the 60 second service.

– ***60 second*** – stabilise the system frequency within the first sixty seconds of a frequency disturbance, and then provide an orderly transition to the 5 minute service.

– ***5 minute*** – Restore system frequency to its nominal 50Hz within the first five minutes of a frequency disturbance, and to sustain response until notified by central dispatch.

Any of these services can be provided by any generator or large interruptible industrial load appropriately registered with AEMO, and may be spinning (currently operating) or non-spinning, as long as they can deliver the service to the prescribed standard. 6 second and 60 second contingency services are usually operated by governor response (or load shedding), triggered by system frequency (measured locally) moving outside of the normal operating band [17]. Detailed requirements for provision of each of these services with regard to control facilities, measurement and verification are outlined [17].

Regulation services are operated by Automatic Generation Control (AGC) with instruction from AEMO [18].

The contingency reserve requirement is determined dynamically in each five minute dispatch interval. It is based upon the largest generating unit output (or load block) in each interval, minus the load relief (the inherent change in demand due to frequency deviation, defined as a function of the load and a load relief factor). The regulation reserve requirement is determined in the manner described in section IV. Regulation service can serve in place of the 5 minute contingency service (although the converse is not true) [19].

Registered generators provide offers for each FCAS service every five minutes in conjunction with their energy offers. The nine markets (eight FCAS services and the single energy service) are fully co-optimised on the single real-time (five minute) platform. All offers can be revised up to the five minute interval immediately preceding dispatch [15]. Regional half-hourly clearing prices (the time weighted average of the six five minute prices) are set for each of the FCAS markets based upon the marginal value of the service. Note that participants in the FCAS markets are procured and the market price set according to AEMO's determined requirement for each service capability in that five minute period. FCAS providers are paid regardless of whether this capability is actually called upon over that period. This differs from the wholesale energy spot market where generators are only paid according to their actual dispatch.

In general, the total requirement for each reserve can be procured globally from all interconnected regions in a co-optimised manner subject to relevant network constraints. Under certain conditions FCAS will be sourced locally (for example, due to regional interconnector constraints or failure). The Tasmanian region is an exception; since Tasmania is connected to the mainland via a DC link FCAS in that region is always sourced locally.

IV. Dynamic Regulation Reserve Setting

Many systems determine regulation requirements ex-ante in a static manner, perhaps varying depending upon the day, hour or season [20]. However, it has been demonstrated that dynamically determined reserve requirements which change depending upon the predicted condition of the system can reduce reserve requirements, and therefore reduce costs [21, 22]. For example, due to the shape of the wind turbine power curve, general variability and uncertainty will be largest when wind farms are operating in the middle (and steepest) part of the power curve. This allows determination of dynamic reserve requirements based upon the expected level of wind generation. However, at present it is rare for regulation reserve requirements to be adjusted based upon the actual predicted conditions of the system (such as wind operation) [20].

In the NEM, the regulation requirement is determined dynamically in each five minute dispatch interval, based upon the accumulated deviation of the frequency over time (the "time error"). Thus, the regulation requirement is adjusted each five minutes, responding directly as required to system variability and uncertainty and other factors that influence frequency (such as inertia).

If the time error is within the +/- 1.5 second band, regulation is set to 130/120 MW (raise/lower). If the time error is outside this band an extra 60 MW of regulation per one second deviation outside the band is added, with an upper limit of 250 MW [18]. The Tasmanian region is a special case; since it is connected to the mainland grid via a single DC link, its regulation requirement is set nominally to 50 MW [23].

The dynamic setting of the regulation requirement in this manner reduces the regulation reserves required, thereby reducing costs. Additional reserves are only procured when they are required. Furthermore, the regulation requirement should adjust naturally over time as more variable renewable generation is installed, responding to the increased variability and uncertainty, and reduced inertia, as necessary. The pre-determined range may need to be adjusted in time as the penetration of variable technologies increases.

V. Causer Pays Cost Recovery

Ancillary services costs are not typically allocated based upon cost causation [20]. In most systems, costs for all ancillary services are allocated to loads [24]. This removes any price signal that would indicate to market participants the cost of their activities which contribute variability and uncertainty to the system. As regulation requirements (and therefore costs) grow over time, it will be important to better signal costs to market participants, eliciting the most economically efficient response.

Payment recovery for FCAS in the NEM is based upon the causer pays principle. As the name suggests, this dictates that the market participants that cause the need for a service are those that pay for it, although there are significant complexities in practice. This is applied in the NEM as follows [16]:

- ***Contingency Raise*** – Contingency raise reserves are maintained to protect against the sudden outage of a large generator. Therefore, generators pay for all contingency raise services, pro-rata based upon energy generation in the trading interval. The relative capacity and reliability of each unit is not taken into account; this could be considered if a more ‘rigorous’ causer pays approach were desired.
- ***Contingency Lower*** – Contingency lower reserves are maintained to protect against the sudden outage of a load. Therefore, loads pay for all contingency lower services, pro-rata based upon energy consumed in the trading interval.
- ***Regulation*** – Payment recovery for regulation services is more complex, since the variability and uncertainty associated with both loads and generators contributes to the regulation requirement. Furthermore, different generators contribute differently to system variability and uncertainty. A specialised Causer Pays methodology is therefore applied as described below.

A. Causer Pays methodology for regulation payments

To assign the costs of regulation FCAS to those market participants who have caused the need for those services, “contribution” factors are determined for each market participant. Contribution factors are calculated every month for all market scheduled, semi-scheduled and non-scheduled generators and loads with appropriate metering [25].

To calculate contribution factors, the actual generation (or consumption) of each generator (or load) is compared with a reference trajectory. The reference trajectory is based upon a straight line ramp from one five minute level to the next, as dictated by central dispatch. Deviations from that reference trajectory are measured every four seconds and averaged over a five minute dispatch interval. Contribution factors are determined based upon 28 days of averaged five minute factors [25].

Participants whose responses assist in correcting frequency deviations are assigned a positive contribution factor, while participants whose responses exacerbate frequency deviations are assigned a negative contribution factor. The higher the contribution to frequency deviation, the higher the factor. Positive factors are discarded on the basis that only causers pay for the cost of regulation. The averaging is conducted over a whole month, with positive factors in some periods being able to compensate for negative factors in others.

Total regulation payments are recovered from participants in proportion to their negative contribution factors [26]. Thus, the cost of the FCAS service is borne by those units causing deviations in the frequency, in proportion to their individual impact.

The NEM’s Causer Pays methodology means wind farms (and other generators) receive more ‘cost reflective’ signals about the cost that they add to the system in terms of increased regulation requirements, than seen in many other industries. This creates better incentives for market participants to manage their own variability if this is economically efficient (by, for example, choosing less variable sites or self-imposing occasional curtailment to limit unanticipated ramps).

This methodology also provides a price signal to generation developers, increasing economic efficiency in the decision on which technology to install. For example, developers can make decisions on whether to install a more variable technology (such as wind) and pay for its associated regulation costs, or invest in a dispatchable technology (such as geothermal) and avoid those costs. Thus, reasonable estimates of FCAS related “integration costs” for variable technologies are made transparent, appropriately captured and passed through to the relevant market participants.

This methodology assigns regulation costs related to both variability and uncertainty. For example, if a wind farm creates variability within a five minute interval, they would pay for the regulation service to correct for that variability. Similarly, if their generation forecast was inaccurate such that regulation service was required to correct the imbalance during a five minute dispatch interval, the wind farm would pay for that cost (since they would have deviated from their expected five minute dispatch level). This creates incentives for market participants to limit variability, and provide accurate forecasts, where it is economically efficient to do so.

Importantly, this methodology is technology neutral, and avoids making distinctions between technologies that may be colored by perceptions. For example, in some cases biomass and landfill gas plant have been identified to be significant contributors to variability; under this system these generators also receive an accurate price signal for the cost of that variability to the system, and could elect to upgrade equipment to operate in a less variable fashion if economically justified. Similarly, variable and uncertain loads will receive the same price signal, depending upon their individual characteristics.

This methodology also has important implications for conventional large thermal units. In some market arrangements, generators are penalized for deviating from dispatch targets regardless of the reason [24, 10]. This may include generators responding beneficially to a large frequency disturbance via the automatic response of their governor. This can incentivize thermal units to deactivate their governor response, reducing their beneficial contribution to stabilizing system frequency [10]. In some systems, a declining primary frequency response has been observed, which may be in part due to these disincentives [27, 28]. This is not an issue in the NEM; if units have operating governors and deviate from their dispatch target in response to a frequency deviation and assist in correcting system frequency they will not be penalized.

VI. FAST PRIMARY FREQUENCY RESPONSE MARKET

No market in the United States at present has an ancillary services market for an autonomous response triggered by the frequency drop associated with a contingency event [20]. Many ancillary service markets include a requirement for a minimum proportion of contingency reserve to be provided by units that are "spinning" (synchronised to the grid). However, there are usually no enforceable requirements for the market participant to be directly responsive to frequency, or for turbine speed governors to be enabled [24].

Primary frequency response in the United States, especially in the Eastern Interconnection, has been declining [24, 28]. This is likely due to a lack of incentives, and in some cases disincentives, as discussed in section V [10]. Furthermore, although it is generally agreed that the addition of variable renewables will have little impact upon the requirements for primary frequency response, if these new entrants are not equipped with these capabilities and displace existing conventional resources that are, the primary frequency response may be degraded [29]. For these reasons, the need for incentivising a primary frequency response in markets in the United States was one of the principal recommendations of a recent IEEE Task Force report [27, 30, 31]. The Western Electricity Coordinating Council (WECC) has been studying frequency responsive service for many years [20, 32], and has started to study the need for a 30 second frequency responsive service [33].

Some systems have introduced mandates that require an emulated inertial response from new entrants [34]. However, this may supply more response than is technically required, increasing costs. Although more complex to implement, appropriate incentives within market designs are likely to be a more efficient approach, especially in large markets where the additional complexity can be justified [10].

In Europe, the European Network for Transmission System Operators for Electricity (ENTSO-E) defines a primary reserve service which must be ensured by all Transmission System Operators. The primary control action is autonomously trigged by a frequency event exceeding ±20mHz. It must start within a few seconds after an incident, be at least 50% deployed within 15 seconds, and must be fully operational within 30 seconds [33, 35].

When a contingency event occurs, a very rapid response is required to arrest the frequency decline. To avoid system collapse, the frequency nadir (minimum frequency) must typically be achieved within the first 5-10 seconds following an event [10]. This suggests that very fast acting reserves are required to respond within the first 5-10 seconds. Slower reserves can then act to recover the frequency over the first 30 to 60 seconds.

Very few restructured electricity markets have defined a primary frequency response this rapid [27]. The NEM and New Zealand are two exceptions [10]. New Zealand procures an 'instantaneous reserve' which must respond automatically to a frequency event. It is defined in two categories: fast instantaneous reserve and sustained instantaneous reserve. When provided by interruptible load the fast instantaneous reserve must be fully activated within one second, and sustained for at least 60 seconds. The sustained instantaneous reserve must be fully activated with 60 seconds, and sustained until advised by the system operator. When supplied by sources other than interruptible load, compliance is assessed on a case by case basis depending upon whether a unit's actual response meets or exceeds its asset capability statement modelled response. Ancillary services are procured via a half-hour clearing market process, or via contracts for a fixed quantity where that is deemed more appropriate [36].

Similar to New Zealand, the Australia NEM has a very rapid primary frequency response market. The 6 second contingency service requires market participants offering the service to fully respond with their agreed capacity within the first 6 seconds following a frequency event.

A detailed monitoring, compliance and verification specification for this service is provided in [17]. Units providing the 6 second contingency service are required to have a control system that automatically, and without AEMO direction, initiates a response when frequency moves outside of the normal operating frequency band. They are also required to measure power flow and local frequency at close to the relevant connection point at intervals of 50 milliseconds or less, to permit verification of their provision of the service to the required standard [17].

VII. OTHER POTENTIALLY BENEFICIAL ASPECTS OF FCAS IN THE NEM

A. *Renewable generators providing FCAS*

In many markets (including most ISOs in the United States), variable renewable resources (wind and solar) are precluded from providing ancillary services [20]. In many cases these technologies are highly flexible and technically capable of providing high quality FCAS. For example, PV plant has almost certainly the fastest downward dispatch response time of any generation technology. Similarly, modern wind turbines can achieve very fast ramp rates. Furthermore, some analysis has shown this to be economic [37, 38], especially in regulation markets, and it is likely to become increasingly economically competitive over time. Excluding these technologies from providing valuable services increases system costs.

The NEM takes a technology neutral approach to the provision of FCAS; any technology that is able to demonstrate the ability to provide a particular FCAS service to the specified standards is allowed to do so. Variable renewables typically register as Semi-Scheduled generators (those above 30MW are required to do so), and under this category are allowed to offer ancillary services [39, 40].

B. Single platform market

In most electricity systems at present, FCAS reserves must be kept constant between day-ahead and real-time markets [20]. This prevents adjustments to those reserves based upon improved information about the system condition in real time. Larger reserves must therefore be scheduled in the first instance, increasing costs.

The NEM design is unusual amongst restructured electricity industries around the world, solving energy and frequency control ancillary services dispatch without any formal day-ahead market [39]. Managing the NEM as a single platform market simplifies co-optimisation of FCAS and energy markets, and minimizes the amount of reserves required by fully taking into account system conditions in real time.

It is also possible that this single platform market structure strongly encourages flexibility from market participants, reducing the need for longer period reserves (such as following reserves) and explicit flexibility mechanisms.

VIII. ADJUSTMENTS THAT MAY BE REQUIRED IN THE NEM

A. Optimise contingency response times

With the entry of large amounts of novel generation technologies, it may prove valuable to revise the 6 second, 60 second and 5 minute contingency response times. These response times are based upon the capabilities of existing generators in the NEM. For example, the synthetic primary frequency response from a wind turbine may be able to respond more rapidly than 6 seconds, yet be unable to cost effectively sustain the response for a full 60 seconds [24, 34]. Revised response times may allow these new technologies to participate more effectively, reducing system costs.

B. Inertia

At present, no electricity system in the world has implemented a market or incentive based reward for generators providing inertia. Some markets (such as Hydro Quebec) have introduced mandatory inertia requirements as a condition of connection [20]. A possible market design for inertia is detailed in [24].

Like many markets, the NEM may need to introduce incentives for the provision of inertia, as non-synchronous generation displaces inertia-providing units. However, it is likely that very high penetrations of variable renewables would need to be achieved before this is a concern (60-80% instantaneous generation) [31, 41]. Inertia has been identified as a possible issue in the NEM which could be addressed via the introduction of an inertia market, or a very fast FCAS service [42, 43]. However, this is not considered urgent.

It may also be worth considering other alternatives to an inertial response. For example, it may be possible for many units to provide a very fast FCAS service which could replace or reduce the need for inertia. Furthermore, as the quantity of non-synchronous generation increases it may no longer be necessary to maintain the system within such narrow frequency bands. These alternatives should be considered in more depth.

C. Following service

Increasing penetrations of variable renewables will demand faster ramp rates of the remaining generation fleet (or an appropriate response from dispatchable loads). In some circumstances, the ramp rates required may exceed the aggregate ramping capability of the generators online, necessitating the dispatch of a faster generator out of merit order. This can distort electricity prices, or may dis-incentivise flexibility [20].

To assist in addressing this issue, many markets include a “following” ancillary service, which provides ramping capability over timeframes longer than the dispatch interval. Other markets are considering the introduction of an explicit flexibility mechanism [44].

At present such a service does not appear to be required in the NEM, with sufficient flexibility being available via the real-time five minute market. Out of merit dispatch due to ramp constraints is rare. However, with increased penetration of variable renewables these occurrences are likely to become more frequent, perhaps necessitating the introduction of a following FCAS service, or an explicit flexibility mechanism to ensure generators receive an accurate price signal for the value of system flexibility.

IX. CONCLUSION

FCAS in the NEM has been criticised by some market participants as being overly complex [45]. However, the detailed design of this market is likely to provide benefits as the proportion of variable renewables increases. The features identified are likely to ensure system reliability and stability at lower cost. The high transparency of these arrangements also offers significant value to market participants, policy makers and regulators. The detailed implementation of these relatively unique and beneficial aspects of the NEM may be able to inform other markets seeking to facilitate lower cost integration of variable renewables.

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