Level 22
530 Collins Street
Melbourne VIC 3000

Postal Address:
GPO Box 2008
Melbourne VIC 3001

T 1300 858724
F 03 9609 8080

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Mr John Pierce
Chair
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

By online submission

Dear Mr Pierce

Frequency Control Frameworks Review: Draft Report

Thank you for the opportunity to respond to the AEMC's Frequency Control Frameworks Review (Review) draft report published on 20 March 2018.

This Review provides an opportunity to undertake a broad examination of frequency control in the National Electricity Market (NEM), and AEMO agrees with the AEMC it complements work already underway reviewing security and reliability settings.

The frequency control framework currently applied in the NEM was established when conventional plant and passive load was the norm. With the power system undergoing widespread changes, it is timely and necessary to re-examine needs and capabilities to ensure that the NEM has a robust, efficient and fit-for-purpose frequency control framework that will be flexible enough to adapt with the rapidly evolving power system.

AEMO supports the AEMC's staged approach to the Review and the adoption of pay for performance approaches. AEMO submits that the staged approach can have two components

- Short-term actions to immediately address the significant decline in frequency performance; and
- Medium to longer-term actions that support the emerging security requirements of the power system more holistically.

A staged approach enables the AEMC, AEMO and market participants to provide technical input to performance standards and relevant services required for correct frequency control in the NEM, while the most appropriate procurement mechanisms are reviewed or developed to enable greater participation by all technologies in the delivery of these services.

AEMO in its own work on frequency control supports the following key principles:

- Correct identification of power system services required to effectively operate the NEM, coupled with tailored performance incentives that ensure Market Participants can deliver these services in an economically efficient manner.
    - A key issue is to correctly identify the technical needs of the power system, including the provision of primary frequency response capabilities, and the technologies capable of providing this need for the system.

Australian Energy Market Operator Ltd ABN 94 072 010 327 www.aemo.com.au info@aemo.com.au
NEW SOUTH WALES QUEENSLAND SOUTH AUSTRALIA VICTORIA AUSTRALIAN CAPITAL TERRITORY TASMANIA WESTERN AUSTRALIA

- Performance incentives for the delivery of these services that are designed once the technical need is accurately defined, so generators and other service providers can look to co-optimise these services where possible with the provision of energy, or other grid services.
    - Any performance incentives should not detract from the delivery of frequency control services, where they are co-optimised with other services such as the provision of energy. Careful consideration in the design or adaptation of existing mechanisms such as Causer Pays to incentivise primary frequency control should be thoroughly explored to avoid unintended consequences.
- Addressing regulatory barriers which may inhibit other resources such as those relating to distributed energy resources (DER) participation in the provision of Frequency Control Ancillary Services.

AEMO looks forward to working collaboratively with the AEMC to develop a comprehensive program of work that will enable the identification and progression of a fit-for-purpose framework in the long-term interests of consumers.

Should you have any queries regarding this submission please do not hesitate to contact Damien Sanford, Executive General Manager Operations via damien.sanford@aemo.com.au or (03) 9609 8340.

Yours sincerely

Audrey Zibelman
Managing Director and Chief Executive Officer

ATTACHMENT – AEMO RESPONSE TO FREQUENCY CONTROL FRAMEWORKS REVIEW DRAFT REPORT

1. Introduction

AEMO, as the market and system operator for the NEM, has the role of administering the electricity market, while ensuring system security and reliability is appropriately managed. One of the fundamental requirements for a secure system is the control of frequency.

In its submission to the Issues Paper, AEMO outlined the importance of frequency control in the NEM. It also discussed how this could be affected by changes that are emerging in the market including a significant shift from passive to active load, fundamental changes in consumer behaviour and a shift from fully-scheduled synchronous generation to variable non-synchronous generation with varying levels of controllability.

While the full suite of solutions to manage and effectively enable this energy transformation requires longer-term development, it is clear that the power system is currently facing operational challenges, some of which relate to frequency control, that must and can be addressed effectively in the near-term.

In this respect, AEMO is supportive of the staged approach proposed by the AEMC which recognises the need for short-term as well as long-term action. Additionally, it should be acknowledged that some of the short-term measures (such as those addressing frequency control issues in the normal operating frequency band) may benefit from further staging. This will allow detailed evaluation of the various primary frequency control measures, and the operational feasibility of implementing them now, and as the power system evolves.

A staged approach can also accommodate linkages to other work underway, such as the Reliability Frameworks Review and rule change on generator technical standards. This will help to ensure that the frequency control framework can be implemented effectively and will evolve with the development of other NEM frameworks to enhance the delivery of secure, reliable and affordable energy to consumers.

The transitional arrangements between immediate action and longer-term change also need careful consideration.

AEMO's key recommended short-term measure involves changing governor settings[1] so that the performance of primary frequency control is immediately improved. This would involve revising governor deadbands to within the normal operating frequency band, and would be applied, in the first instance, to generators where minimal adjustment is required.

This measure, supported by various complementary actions, such as tuning of Regulation FCAS quantities and control system optimisation (for both AEMO and participants), is intended to address system security concerns associated with continued deterioration in frequency control[2].

Assessment of these actions would then inform the development and implementation of a mechanism that delivers effective longer-term frequency control. AEMO believes this would be best achieved by paying for the provision of primary frequency control that is valued according to the level of service required to maintain power system security. AEMO looks forward to further developing the detail of this approach in consultation with stakeholders,

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[1] Subject to a successful trial discussed later in the submission.

[2] Refer for example to DIgSILENT's paper: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf

including the AEMC, to ensure the most appropriate mechanism is introduced in the long-term interests of consumers.

The remainder of AEMO's submission below addresses the AEMC's recommendations in the Review draft report, and provides more detail on the basis for AEMO's recommendations. It also addresses matters relating to providing greater transparency of information to the market.

2. Changes to the causer pays procedure

AEMO has been conducting a review of its 'Causer Pays' procedure.[3] The draft report was published on 6 April 2018[4] and initial changes are expected to be implemented mid-year. The Causer Pays procedure review has considered similar issues to those raised in the Review, and thus should be considered alongside the recommendations made by the AEMC.

The AEMC has recommended investigation of the following matters:

- Alignment of the sample and application period for Causer Pays factors
- Removal of 10 business day notice period for Causer Pays factors
- Visibility of frequency indicator (FI) data
- Clarity of the Causer Pays procedure
- Introduction of a positive incentive for primary frequency control within Causer Pays

These are considered individually below.

2.1. Alignment of the sample and application period for Causer Pays factors

AEMO recently explored changes to the sample and application factors (and potentially even "real-time" factors) with respect to Causer Pays. At that time, the analysis concluded there were insufficient benefits to warrant changing to more dynamic factors. This analysis showed the potential for undesirable consequences to result from such a change including increased volatility, lack of certainty, and disconnection between incentives to avoid costs and maintaining reliability and security. The Causer Pays Draft Determination (link provided in footnote) describes these matters in further detail. AEMO however would welcome further engagement with the AEMC on this issue as the Review progresses.

2.2. Removal of 10 business day notice period for Causer Pays factors

AEMO suggests that Market Participants are best placed to provide advice on the value-add that would result from this recommendation compared to the current approach. AEMO notes however that this change would require augmentation of some AEMO internal processes to ensure the shortened timetable can be reliably met. The time to accommodate these changes should be considered in the application date of any regulatory change, should this be the outcome.

2.3. Visibility of frequency indicator (FI) data

The Review's draft report suggests that knowledge of the frequency indicator (FI) ahead of time could inform operational decisions. However, these parameters are not currently forecast by AEMO or any other market participant in the NEM, and AEMO is unaware of any

[3] The procedure for determining contribution factors for the recovery of frequency regulation costs under National Electricity Rules clause 3.15.6A(k)

[4] https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

international markets which perform such forecasts due to the higher probability of producing inaccurate data.

The provision of FI data ahead of time would require accurate frequency forecasts for every 4 second interval in the forward-looking horizon, as well as 4-second operating points and control limits for each generator enabled for regulation FCAS[5]. Frequency cannot be accurately forecast over this timeframe, as it depends on an extremely high number[6] of potential random and semi-random events. Furthermore, generator operating points and control limits are mostly only visible to and controllable by AEMO at real-time. Therefore forecasts of these elements would have very poor accuracy and as such, in AEMO's view would not be informative for participants.

To provide the enhanced transparency of FI data intended by the AEMC, the current Causer Pays review will publish FI data shortly after real-time, for example every 30 minutes for the previous 30 minutes. This will allow participants to make more informed operational decisions in terms of frequency responsiveness and dispatch compliance going forward.

2.4. Clarity of the Causer Pays procedure

AEMO supports increasing the transparency and education of the Causer Pays process to stakeholders. As such, AEMO has published revised guidelines to complement its Causer Pay Draft Report and Determination[7]. AEMO also plans to publish information that includes worked examples on the calculation of performance factors. This accompanying information will enable greater transparency and clarity of the process.

AEMO encourages participants to provide feedback to AEMO on the newly published information, and the Causer Pays review in general.

2.5. Introduction of a positive incentive for primary frequency control (PFC) within Causer Pays

AEMO supports performance incentives for the delivery of grid services, including primary frequency control. Correctly tailored performance incentives that ensure Market Participants deliver these services to a specific technical standard remains critical to good frequency control.

Informed through its own work on frequency control, AEMO supports the following key principles:

- Correct identification of the technical needs of the power system, including the provision of primary frequency response capabilities, and the technologies capable of providing this need for the system.
- Performance incentives for the delivery of these services that are carefully calibrated to address the known technical requirements, so generators and other service providers can look to co-optimise these services where possible with the provision of energy, or other grid services.
- Performance incentives should be designed to avoid sub-optimisation of the delivery of frequency control services, but rather, should consider how they can be provided in

[5] These data points are necessary to calculate FI values. More detail may be found in AEMO's new description of the Causer Pays methodology at the link in the footnote above.

[6] In the order of thousands

[7] Refer to the document *Regulation FCAS Contribution Factors Procedure* at the following link: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

a co-optimal manner, including provision of energy. The potential unintended consequences in the design or adaptation of existing mechanisms such as Causer Pays to incentivise PFC should be thoroughly explored.

AEMO notes that introducing incentives for PFC into the existing Causer Pays mechanism if not carefully considered may lead to a further increase in the complexity of the process, as well as the potential for distortionary impacts. Additionally, AEMO recommends any incentives for PFC should be harmonised with the arrangements for localised recovery, to avoid PFC costs being disproportionately allocated to specific regions during periods of local requirements, or favouring participants with larger portfolios over those with small (or singular plant) portfolios.

AEMO's Causer Pays review is seeking to address the most significant known disincentive to providing PFC within the current regime[8]. AEMO has also identified changes to the Rules regarding the Causer Pays residual allocation and consideration of regional Causer Pays factors which should encourage better PFC performance. AEMO welcomes the AEMC's participation in this review, which may complement the AEMC's Review.

3. Frequency monitoring and reporting

The AEMC has recommended that a new Rule be introduced that would establish a requirement for AEMO to monitor and report on frequency performance. AEMO has recently introduced monitoring and reporting on the NEM's frequency control performance on a quarterly basis[9].

AEMO supports the mandated reporting obligation in the Rules and recommends the Rules specify the timing and high-level content of the reports, with a complementary Guideline developed by AEMO in consultation with stakeholders to provide the required level of detail for the reporting that can be updated when appropriate. AEMO suggests that a set of agreed frequency control performance measures could be provided regularly, for example weekly, while full reports including the detailed analysis could be provided quarterly.

Additionally, AEMO sees benefits to the AER reporting of FCAS market outcomes in relation to the providers of FCAS (performance of service delivery), FCAS prices and FCAS volumes. As information required for the AER's FCAS reports would be reliant on information presented through AEMO's frequency reports, it is recommended to align the timing of the two reporting processes.

4. Primary frequency control under normal operation

The Review draft report recognises the critical role PFC plays in maintaining frequency within the normal operating frequency band. It also notes that there is an urgent need to prevent any further deterioration of PFC and encourages an increase in the provision of this service through either of the following preferred options:

1. Requiring the delivery of PFC from existing Regulation FCAS providers as part of this market, or

[8] That is ignoring 4-second intervals where the Frequency Indicator (FI) opposes instantaneous frequency. Therefore PFC actively supporting instantaneous frequency will not affect generators' Causer Pays outcome.

[9] Available on the AEMO website: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring

2. Providing a positive incentive for PFC through the Causer Pays mechanism.

AEMO however believes that the delivery of effective and sustainable PFC in the required volumes[10] under normal operation would be best achieved by:

1. A requirement for generators to provide PFC in the short-term via their governor control systems. We propose the cost of PFC would be incorporated into the cost of supplying energy to address the immediate need for improved PFC performance in the NEM, and
2. An explicit procurement of PFC by way of a payment mechanism as a medium to longer-term measure.

Sections 4.2 and 4.3 explores these matters further.

4.1. Relationship with Regulation FCAS

The provision of PFC via governor settings was mandated in the Rules until late 2001 when the FCAS markets commenced[11]. Since then, the primary control response to maintain frequency deviations within the NOFB has not been explicitly recognised through either regulatory or market mechanisms. For this reason, some stakeholders have raised concerns that current frequency control issues may be a result of inadequate volumes and/or performance of regulation FCAS.

AEMO sees benefits of a review of regulation FCAS volumes and settings and is currently undertaking work in this area. However, tweaking the volumes and response of regulation FCAS, a form of secondary (slow) frequency control, cannot resolve the current lack of primary (fast) frequency control in the NOFB.

AEMO's advice provided to the AEMC on request on 5 March 2018 demonstrated how these services are fundamentally different and not interchangeable, and that both are vital to the effective management of frequency[12]. In particular, PFC provides fast control action that responds rapidly to contain frequency deviations, while secondary frequency control (SFC) is a slower control action that acts to relieve PFC providers so that they can respond again if required to restore the supply-demand balance.

4.2. Required volume of PFC

PFC action requires that a significant proportion of the generation fleet is enabled at all times for the continuous provision of that service. AEMO's modelling suggests that greater than approximately 30% of the online fleet should be actively providing PFC at any given point in time for an effective primary response characteristic. However, the requirement must be significantly higher than this to allow for the fact that not all of the PFC-enabled plant will always be responsive[13.]

AEMO's finding is similar to the findings from work being undertaken by the North American Electric Reliability Corporation (NERC) which is investigating declining system frequency response. Results from this work to date have shown that only approximately 30% of the

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10 See Addendum for further detail on PFC volume requirements.

11 The market established in 2001 for the purposes of frequency control within the normal operating frequency band was the Regulation FCAS market.

12 https://www.aemc.gov.au/sites/default/files/2018-03/Advice%20from%20AEMO%20-%20Primary%20frequency%20control.PDF

13 Plant may sometimes not respond, or respond less than usual due to fueling issues, available headroom, plant issues, control points, operating modes, etc.

fleet was routinely providing a correct primary frequency control response[14]. As a result all new generators (both synchronous and non-synchronous) are to provide a primary frequency control response in accordance with a Federal Energy Regulatory Commission (FERC) Order[15] made in February 2018. Additionally, many other international jurisdictions[16] have mandated the capability and/or provision of primary frequency control from generators of significant size[17] so that a higher volume of PFC is available to be provided.

The reason such a volume is required for satisfactory performance is because generator movements must be kept to a small fraction of the unit output. This allows movements to be sufficiently responsive and able to be sustained and repeated as required, noting the nature of PFC is to continually act to contain normal frequency movement without requiring too much headroom.

This volume of PFC, while avoiding frequent and rapid changes in frequency under normal operating conditions, also helps to achieve a broad geographic distribution of service[18]. As such, options that require existing regulation FCAS providers to also provide PFC, or that bring the contingency service trigger point closer to 50 Hz, would not be effective as they would not acquire suitable levels or distribution of PFC.

Addendum 1 shows a worked example of the requirements for the provision of PFC under normal operation that must be enabled in order to be effective and sustainable. It is noted that these requirements may change over time as the capabilities of the fleet evolve.

4.3. Options for the provision of adequate levels of PFC

It has been recognised by all parties that there is an immediate need for improved performance of frequency control within the NOFB in the NEM.

As a first step, AEMO recommends trials to establish revised governor settings for a period of time so that the impact of changes made for the provision of PFC in the NEM can be assessed. This would involve tightening deadband settings on governor systems to within the NOFB. Any regulatory or market arrangements to deliver PFC should be considered on evaluation of the outcomes of these trials. This has been the approach applied in other markets around the world and the Wholesale Electricity Market (WEM) in Western Australia,

While a form of payment mechanism would be the most effective solution for the procurement of PFC in the longer-term, the design of any mechanism must build on the underlying technical needs of the system. This must be based on the engineering requirements necessary to achieve effective frequency control and should be considered in light of a rapidly changing generation mix.

AEMO is working with a group of industry power system experts from across the NEM to scope trials that could be undertaken in Tasmania or the mainland.

AEMO welcomes further discussion with the AEMC and Market Participants on any proposed interim option, along with the proposed trial. In parallel, AEMO also proposes to work with the AEMC and stakeholders to develop an effective payment mechanism for the procurement of PFC in the longer term.

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[14] https://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[15] https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-2.pdf

[16] Including the UK, Ireland, New Zealand and Texas as examined by the AEMC in their Draft Report.

[17] This varies by jurisdiction, but generally applies to scheduled units over a particular size, e.g. 30 MW in NZ, 100 MW in the UK.

[18] Although this level of participation on its own may not necessarily deliver the most optimal geographic distribution in all cases.

5. Regulatory barriers to distributed energy resources

Distributed energy resources (DER), if well managed, present operational opportunities for the power system. However, without the correct coordination of these resources, continued installation of DER can present operational challenges.[19]

AEMO recognises that to maximise the contribution from DER at times of high DER potential, accessing system services from DER is likely to become a necessity. The Review focuses on how the frameworks under which DER connect, operate and participate in the NEM can be designed so as to enable the effective provision of system security services; specifically FCAS. However, the removal of regulatory barriers is only one requirement to unlock the potential of DER. The potential impacts and opportunities of DER with regard to system security and reliability need to be assessed more broadly. Focusing only on facilitating participation in FCAS markets may inadvertently create other barriers to broader DER participation in the NEM.

Any framework should also incorporate measures that recognise and address how DER may increase the need for FCAS. Additional value may also be gained via increased competition in FCAS provision. Where DER cannot provide certain system services, low cost DER may need to be curtailed in exchange for higher cost resources, leading to market distortions and inefficiencies.

AEMO sees aggregation as the best way for DER to participate in markets. For FCAS specifically, aggregation will facilitate participation via the required integral MW bids. Since NEM operating systems are designed around this requirement, it provides a level of efficiency in the market in how service providers are procured. A portfolio of aggregated units such as DER is likely to have a reserve or headroom that is based on local conditions from which the integral MW is sourced, aggregated, bid and dispatched. That is, an aggregator may have a portfolio of 1.4 MW but given constraints in the distribution network or cloud cover, may not be able to reliably dispatch all units. The integral MW requirement effectively creates headroom that may in fact provide greater opportunities for aggregated DER to participate as resources can be drawn from areas where there are fewer network constraints in a given dispatch period.

The associated cost in systems changes, registration, dispatch, verification of service provision and settlement would need to be weighed against the benefits of the service, while noting the practical consideration that the impact on the power system of individual sub-1 MW services would likely not be readily measurable. A thorough analysis of the cost of changing the system to accommodate bids less than 1 MW has not as yet been performed and should therefore be reviewed before any decision is made.

AEMO is working with industry on the power system architecture requirements in order to efficiently integrate DER. This has highlighted the need to address the regulatory barriers identified by the AEMC, as well as other issues, outlined below.

[19] DER refer to technologies such as rooftop photovoltaics (PV), energy storage, electric vehicles, home energy management systems, and active shifts in load that are embedded in the distribution network.

5.1. Registration categories

As outlined in the Review draft report, the small generation aggregator (SGA) and market ancillary service provider (MASP) frameworks provide for the aggregation of DER, but neither accommodates the aggregation of small generating units for the purpose of providing market ancillary services. As a result, DER that are capable of exporting electricity to the network cannot currently be aggregated to offer market ancillary services.

AEMO supports appropriate changes to the registration categories but it is important that any changes are made in the broader context of the evolving market. Revision of the SGA and MASP categories solely for FCAS is unlikely to provide appropriate coverage of all the related challenges related to the integration of DER.

For example, the registration and classification process in the Rules needs comprehensive review to account for all aspects and implications of:

- Storage technologies like batteries which can operate as both generation and load.
- Assessing SGA and MASP categories to ensure they accommodate all potential technologies.
- New business models such as Virtual Power Plants (VPPs) that may be subject to specific operational requirements.

Consideration of different operational requirements is important as the expected growth in DER, including small-scale batteries (less than 5 MW), will have associated impacts on power system operation. If unscheduled operation of VPPs grows, there is the potential that large, rapid ramps could dramatically increase the need for FCAS associated with growing forecast errors. This could be mitigated by the registration of VPPs and their inclusion in the central dispatch process. In this respect, any proposed changes to NEM registration categories should consider the thresholds, criteria and conditions for the participation of aggregated DER.

Factors to consider include:

- Telemetry required, in particular what degree of real-time monitoring or SCADA information is required for adequate system operability.
- Degree of geographic disaggregation required to allow inclusion in both distribution and transmission level constraints and assist in managing variability.
- Thresholds at each node, as well as in aggregate across the region/system.
- Requirements for compliance with dispatch targets, and whether more lenient criteria can be applied, compared with other scheduled resources.

In the first instance, significant VPPs should be required to provide AEMO with real-time monitoring information to facilitate accurate operational generation and load forecasts.

Consideration of the regulatory barriers to participating in FCAS should also address the need to create pathways for multiple parties to access a customer (i.e. allowing for aggregators other than the customer's retailer), without having to create and pay fees for a duplicate NMI and connection point. This would further expand the opportunities for innovation in DER aggregation for FCAS provision as well as active market participation.

AEMO recommends that any work that is undertaken to address the regulatory barriers, in this case associated with DER participation in FCAS, must be considered holistically and consistent with the broader DER strategy for the NEM.

5.2. Market ancillary services specification

The market ancillary services specification (MASS) sets the capability requirements for participants to be able to offer each type of FCAS, and specifies how FCAS performance is measured and verified. These specifications require the measurement of power flow and local frequency at or close to the connection point within particular timeframes. These specifications, as applied to aggregated DER which have multiple connection points, can create an economic and data impost on participants.

AEMO has been working with stakeholders on issues raised with the MASS, and is looking to also be involved in trials that demonstrate the capability of DER to provide fast FCAS, as well as other system services. AEMO will be developing frameworks which outline what these trials should address, and will use outcomes to modify the MASS where appropriate.

In particular, AEMO is looking to demonstrate:

- The ability of DER to reliably provide the current eight FCAS categories and particularly the faster services.
- Capacity to provide frequency control services faster than the current requirements, which could inform the changes in how frequency control services are specified in the future if found to be more effective and efficient.
- An efficient approach to measuring and verifying the performance of FCAS from aggregated DER. This may involve sampling across a set number of generating units that have high speed monitoring with the remaining generating units having low speed metering. An appropriate balance between the required enablement and response technology and economic cost of these specifications is essential to ensure the efficacy of FCAS performance is not compromised.

In particular, with the emergence of VPPs, these trials should be prioritised according to likely attainable benefits as measured in accordance with the NEO. The outcome of trials will be reflected in the MASS during its review.

5.3. Connection arrangements and AS 4777

The AEMC has indicated that connection frameworks in Chapter 5A of the NER and Australian Standard (AS) 4777 may limit the ability of DER to participate in system security frameworks. AEMO agrees with the AEMC’s view that the connection framework should be timely, adaptive to local DNSP requirements, and provide consumers with the opportunity to optimise the value of their DER.

Furthermore, given the large volume of rooftop PV already installed, the NEM connection frameworks also need to take into account system security impacts of DER. This may not be as simple as considering whether technical requirements are clear, proportionate and relevant to the specific technology and how it will be operated. Given the potential of DER to act in aggregation, whether through direct coordination or through external signals such as tariffs, technical requirements must be considered in the context of high penetrations of DER and potential changes in how they are operated. Without considering the system as a whole, the technical requirements may inadvertently impact power system operations or stymie the opportunities available to consumers.

AEMO is working to understand the behaviour of DER technologies during power system disturbances. For example, on 3 March 2017, a disturbance in South Australia resulted in around 40% of the installed rooftop PV in the region disconnecting, though the cause of disconnection has not yet been ascertained.[20] Preliminary analysis of three events in Victoria from January – March 2018 has similarly shown that the response of DER to disturbances is unpredictable, and depends on externalities such as ambient conditions, technology type and age. Understanding such behaviour will help inform the development of more appropriate technical standards which can facilitate the participation of DER in a broader range of services.

Technical standards may also provide an efficient way to equip consumers with the capability to participate in future value streams. For example, participation through an aggregator or provision of network services requires the ability to dynamically control DER remotely. While consumers may not wish (or there is no value) to participate in system or network services at the time of installation, technical standards mandating that capability will facilitate their participation at a later date should more opportunities arise. The costs and benefits of such standards would need to be assessed against the costs and barriers to retrofitting the capability to existing DER systems. Another potential benefit of technical standards is the ability to increase the local hosting capacity of the network. That is, if DER that is installed in a particular local network can be coordinated, then more DER can be installed overall, increasing the number of consumers who can choose to install DER and potentially participate in the market.

Technical standards that allow operators to dynamically control feed-in are likely to be needed to operate the power system safely and securely during rare, emergency events.

In the Review draft report, the AEMC suggests that the Rules are not the appropriate place for technical standards for DER. However, the process of revising AS 4777 is lengthy, and is broader than connection requirements. Given the rapid evolution of the power system and DER technologies, it is appropriate to consider how the industry can ensure that the technical standards are revised in pace with the changes observed in the power system. AEMO has commenced an investigation of the technical standards that it believes need to be applied to DER from a security and reliability perspective, including consideration of how the different regulatory instruments and standards might be best leveraged.

5.3.1. Energy Network Australia's development of national connection guidelines

AEMO is supportive of the development of national connection guidelines, and will continue to work closely with ENA and other stakeholders on these with a focus on power system security.

National connection guidelines will provide greater consistency in the requirements for connection of DER, however the limitations of this approach must be recognised. Firstly, complete consistency across the jurisdictions will not be efficient or feasible, with DNSPs requiring some flexibility depending on the specific needs of the local network. Secondly, it is not proposed that these national connection guidelines would be mandatory for DNSPs, so

[20] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Report-SA-on-3-March-2017.pdf

their consistent application will depend on individual DNSPs' willingness to adhere to them, in the absence of any regulatory obligation

The AEMC also stated in the draft report that the connection arrangements at present do not value or incentivise DER to provide system services. The role of connection arrangements and technical connection standards across all technologies (both utility and distributed scale), is to equip the power system with the capability required for safe, secure and reliable operation. AEMO's view is they are not the appropriate avenue to incentivise or compensate for the provision of system services. As outlined above, technical connection standards for DER that allow remote control would provide value in so far as they provide consumers with the dormant capability to provide services via an appropriate mechanism. This approach would be valued against the cost of retrofitting capability[21].

5.3.2. Trialling the provision of FCAS from aggregated DER

The AEMC has identified the risk that the provision of FCAS via DER may impact local network conditions, and conversely, local network conditions may also affect the ability of DER to provide system services. The third dimension that needs to be considered is the technical response of inverters discussed above that may restrict the ability of DER to provide system services under some or many network conditions. This concern was also raised by TasNetworks in their submission to the Issues Paper.

AEMO is supportive of the "heat map" approach to signalling opportunities for investment in DER to provide local network services. It is also clear that greater communication between AEMO and DNSPs is required in the first instance to mitigate against potential impacts on the local network or the power system due to a coordinated operation of DER, for example through VPPs.

AEMO has been working with the ENA to explore the technical and physical system architecture that will be required to effectively integrate DER into the power system. The co-optimised dispatch process will require the ability to develop and integrate dynamic distribution network constraints to manage a secure and reliable dispatch of energy. This in itself is a complex process that requires greater monitoring of the distribution level, and the collection of associated data.

Through its broader DER program, AEMO is working with key stakeholders to understand, trial and develop the required technical, regulatory and operational frameworks by:

- Working with the ENA to develop a White Paper exploring the system architecture required to efficiently integrate DER. A consultation paper is expected to be published in mid-2018.
- Working with stakeholders to learn from trials currently underway, and to develop new trials that explore the technical requirements that will enable the participation of DER in the NEM.
- Drawing on international experience in integrating DER, including dynamic PV feed-in management and system architectures.

[21] Germany was forced to retrofit its fleet of rooftop PV inverters which were all set to disconnect at the same point in an over-frequency event. The retrofit of 315,000 inverters cost around $300 million.

6. Medium term work

AEMO advocates a staged approach to changes in the frequency control frameworks will deliver the most efficient outcomes. While PFC has been identified as a current key issue, broader changes to the frameworks must take into account the fundamental needs of the system in terms of frequency control, which will then prescribe the service specifications that match these needs and the appropriate procurement mechanisms.

Any assessment of the need for changes to the framework in the longer term must be cognisant of the linkages with other work underway such as the minimum inertia requirements, generator technical standards review, and of course, the primary frequency control discussions within this Review.

As outlined in AEMO's Power System Requirements paper[22], there is a range of technical attributes that are required to maintain power system security and reliability. These can be classified into various broad categories, several of which can also be grouped by the physical characteristics of the balancing services they provide to ensure supply and demand are balanced over various timeframes.

Frequency control is one of the more familiar balancing services, with the current regulation and contingency FCAS defined over periods of 6 seconds, 60 seconds and 5 minutes. Figure 1 shows the current and potential future services that could be procured in the NEM to respond to imbalances between supply and demand.

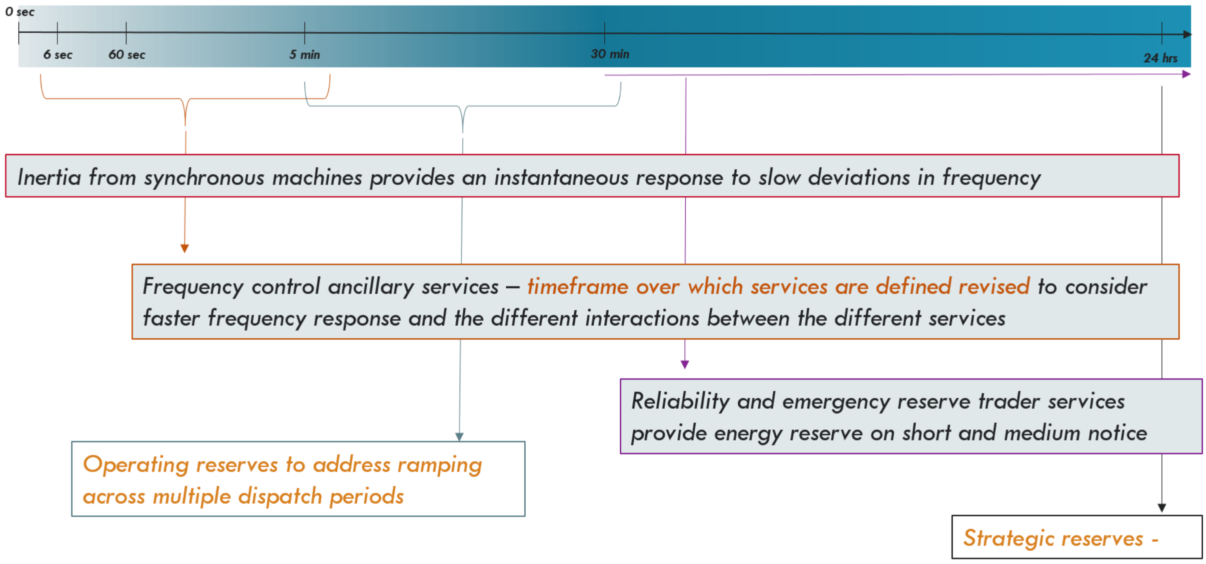

Figure 1 - Summary of balancing services

Each of the services acts over a different timescale. The potential new services include a redesign of the current FCAS specifications if appropriate and a potential operating reserve service to manage ramping events that occur over several dispatch periods, for example due to the ramp down of solar in the late afternoon.

Depending on the needs of the power system, the dispatch of some of these services may need to be co-optimised. For example, there may be a level of interchangeability between

[22] AEMO. *Power System Requirements* paper, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf

inertia above a certain threshold and fast frequency response services, and operating reserves may also need to be co-optimised with FCAS.

As set out in the Review draft report, there is a need to broadly assess future FCAS needs and their drivers, both at the distribution and transmission level. Furthermore, it is anticipated that as the power system evolves, the value of market ancillary services relative to energy will increase, and the needs assessment will facilitate the appropriate signals to send to the market.

AEMO is keen to work with stakeholders to continue to explore how best to define technical, operational and regulatory frameworks that deliver an efficient, reliable and secure power system in the long-term interests of consumers.

Addendum 1 – Example of primary frequency control volume requirements

This example demonstrates the reason PFC must be enabled across a very significant proportion of the generating fleet in order to obtain an efficient and sustainable system response in the normal operating frequency band.

The following terms are used heavily and thus are defined here for clarity:

- **Droop**: Droop refers to how generators supplying PFC respond to a change in frequency. A droop setting of 4% means that a generator will move its output to its fullest capability for a 4% change in frequency from the nominal level; 50 Hz in the NEM. This means for a 4% rise in frequency (52 Hz) the generator would move to its maximum output, or for a 4% fall in frequency (48 Hz) the generator would move to its minimum output (assuming zero deadband). Note that this is a 'proportional' response because the amount the generator moves is proportional to the deviation from nominal frequency.
- **Deadband**: A deadband is a frequency band within which the generator's primary frequency control (droop) response is blocked. If a generator's deadband was set to say +/- 0.1 Hz, then frequency movement between 49.9 Hz and 50.1 Hz would not elicit any PFC.
- **Load relief**: Load relief refers to the natural behaviour of electrical load to decrease as the frequency declines. This is due particularly to motor loads; a basic electrical motor will draw less power at a lower frequency. A load relief of 1.5% means that the load reduces by 1.5% for a 1% reduction in frequency.

The example assumes the following parameters, which are based on current typical daytime conditions in the NEM:

- 22GW NEM demand
- 36GW total available plant online
- Total headroom of 14GW (based on demand and plant online; i.e. 36 GW – 22 GW).
- 1.5% load relief.

It is then assumed for this example that some varying proportion of the total plant online is provides PFC at an average 4% assumed droop characteristic and no (or a negligible) deadband. A 4% droop is within the range of typical settings used in jurisdictions around the globe.

The chart shows how the primary response of generators would behave for a **250 MW supply-demand mismatch.** 250 MW is ~1% of a 22 GW demand, and so represents a significant but not extraordinary mismatch. The proportion of the entire online generation fleet that responds is then assessed, covering 1% up to 50% (or 360 MW up to 18,000 MW). The chart also shows the minimum (steady-state) frequency that would be reached.

This chart demonstrates how thousands of MWs of plant must be actively providing PFC in order to achieve a sustainable response. This is because if only say 1% (360MW) of plant provides primary response, the frequency change is large, and the plants have to move by a significant margin in response; some ~15% of their rating. Most plant could not do this quickly, if at all, and would certainly not be able to sustain it long. However, if 50% of the fleet (18,000 MW) is providing a primary response, the frequency drops only a very small amount and each plant moves only ~1.5%. This is much more achievable and can be sustained far longer; that is, it can be sustained and repeated indefinitely, as is required for managing the normal fluctuations that occur continuously. Note that between around 30% and 50%, the curves flatten out considerably, demonstrating how there is significantly diminished value from increasing the proportion of frequency-responsive plant further.

In a practical application, some proportion of the plant technically capable and enabled to provide PFC might not actually be able to respond to a frequency deviation. This might be due to issues such as plant or fuel factors or lack of operating headroom. For this reason, it is necessary to ensure a higher proportion of the generating plant is enabled to provide PFC than is technically required for adequate system response. It is difficult to assess what this ‘buffer’ should be other than through acquired operational experience. International jurisdictions with mandatory PFC, such as in North America, should provide useful data on this matter.