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AGL Energy (AGL) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC) Issues Paper on Frequency Control Frameworks Review (Issues Paper).

AGL is one of Australia's largest integrated energy companies and the largest ASX listed owner, operator and developer of renewable generation. Our diverse power generation portfolio includes base, peaking and intermediate generation plants, spread across traditional thermal generation, battery storage and renewable sources. AGL is also a significant retailer of energy, providing energy solutions to approximately 3.6 million retail customers throughout the National Electricity Market (NEM).

As the generation mix changes to incorporate a growing amount of renewable energy, it will become more difficult to accurately match supply and demand. Demand for energy services such as Frequency Control Ancillary Services (FCAS), reactive power, and inertia will also be likely to increase as the traditional suppliers of these services exit the market.

As guiding principles, AGL supports market-based approaches and technology neutral frameworks to achieve system security outcomes. These will be the most likely to provide optimal outcomes for consumers at the lowest cost.

AGL considers the best option or combination of options for market reform is currently unclear. Proposals for changes need to clearly identify the issues with existing frameworks, demonstrate that proposed changes will be effective and recognise that there could be unintended consequences, both on existing generators and on new entrants.

In relation to the topics raised in the Issues Paper, AGL makes the following general comments:

- Primary frequency control: AGL considers it is important to create market-based incentives that encourage participants to provide primary frequency control. Mandatory requirements, such as a mandatory governor response, are not consistent with this principle.
- FCAS markets: AGL supports further consideration of whether it is necessary to support faster frequency response within the FCAS framework. AGL notes that introducing more FCAS markets and categories will add complexity for participants. Therefore, it may be best to undertake a holistic review of the settings in FCAS markets to determine the optimal number of and timing for different services.

- Distributed energy resources (DER): AGL supports technology neutral outcomes that enable DER (or any other emerging technologies) to provide system security services. This should be provided through competitive markets, which are more likely to provide better outcomes to consumers at the lowest cost.

More broadly, the requirements of the power system, such as voltage control and inertia, need to be also considered when designing changes to frequency control frameworks. This review should also be mindful of the impacts of new requirements on existing generator performance standards.

AGL has provided responses to the Issues Paper in Attachment A.

If you have any queries about the submission, please contact Meng Goh on (02) 9921 2221 or mgoh@agl.com.au.

Yours sincerely,

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Head of Energy Market Regulation

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<u>**Attachment A**</u>

<u>AGL View on the Issues Paper</u>

<u>Primary frequency control</u>

AGL considers there are currently several disincentives for generators to provide governor response and as a result, some generators have widened the dead band and reduced droop control. If a generator changes its output in response to a frequency event but *due to monitoring issues is unable to verify this with AEMO*, the generator is deemed to have not followed dispatch instructions and the existing causer pays arrangements allocates costs to these generators.

AGL's Loy Yang power station was consistently being exposed to causer pays during frequency events when the governor was in operation. Once the droop control was disabled and the unit allowed to run only at AEMO set-points and to provide FCAS, the number of causer pays events dropped dramatically.

Not only should these disincentives be addressed, but generators providing governor control response be incentivised to do so.

AGL does not support a mandatory requirement for all generators to provide primary frequency control. Some generators can provide primary frequency control at little cost – they already have the capability and may only incur costs from wear and tear. Other generators are not well set up to provide primary frequency control and may require the installation of specific technology, which may make the project unviable and could stall the development of new capacity. Since mandatory frequency control was abolished and FCAS markets introduced, a number of smaller/simpler generation systems have been constructed that are not capable of providing any sort of high speed frequency control. If these units were required to retro-fit and provide primary frequency control, it could affect the economic recovery of the asset.

In general, AGL supports a market based approach for primary frequency control that can be competitively provided by a technologically diverse range of generation and load. AGL considers a market based approach will likely result in the most cost-efficient outcome.

However, AGL notes that it may be difficult for some older hydraulic generators to participate in FCAS markets because the governor technology does not allow the governor response to be easily turned on or off throughout the day. AGL acknowledges that it is possible to upgrade an older hydraulic governor to enable it to turn on and off easily to participate in FCAS markets. However, these upgrades may be cost prohibitive. If governor response from these generators is considered necessary, another mechanism such as a long-term contract to provide governor response at particular settings may encourage these generators to provide the service.

AGL would also like to make the following points in response to Chapter 5 of the Issues paper:

- The long-term effects of sudden and large frequency changes on generator components are not yet fully understood by industry and it may be some time before the wear and tear on generators presents itself. For example, boiler systems in a thermal generator are unable to maintain output with a sudden drop in steam pressure. The long-term effects of the cycling of the boiler pressures are unknown at this stage. Fluctuating frequency can also make it more difficult for large generators to synchronise with the network and come online. These concerns and others need to be balanced by generation asset operators and can more accurately be managed and priced through internalised costs and market mechanisms rather than rigid frameworks that may be inefficient or uneconomic.

- It can be difficult to prove that a generation system performed as expected during an FCAS event. Payment can only be made once it is proven that a generator performed as expected. Improving the modelling and verification tool and real-time metering would enable generators to provide or receive an accurate pass/fail result during events.
- With regard to the suggestion in the Issues Paper that there should be an availability reserve, like 3% as in Argentina, AGL considers that if this is considered further, there must also be some financial benefit for the generator for the lost opportunity cost for electricity generation. Some of the questions and issues with this option include:
  - Is the constraint based on total MW output or potential MW output?
  - How long is the generator expected to run at the higher value?
  - Hydro units that require balancing of water management may experience issues in holding back a percentage of generation.
  - Unused wind and solar resources cannot be stored for later and are wasted.
- In general, AGL is supportive of more regular reporting on frequency. This will alert the market to the need for FCAS services and provide trend information which will assist potential investors with the timing of their investments. It will give generators a better understanding of how often and by how much the frequency is deviating. It will also be helpful to monitor the effect of any changes made to improve the frequency response.
- Primary frequency control is important where a generator is physically located in one jurisdiction, but connected to transmission infrastructure in another jurisdiction. If those regions become separated it is necessary to rely on primary control at the point of connection instead of regulating FCAS that is determined by physical jurisdiction. This was highlighted during the Victorian bushfires where NSW and Victoria separated. The Victorian hydro units were connected into the NSW transmission network, but receiving Victorian FCAS set-points.

FCAS markets

The electricity market is in transition and more changes will eventuate with the increased penetration of distributed generation, household batteries and electric vehicles. Demand response is also becoming more attractive as an active emergency reserve and there is considerable potential to leverage demand response for frequency control (eg such as is used in New Zealand). Any changes to FCAS must leverage these resources as well as more traditional generation resources available today.

Without understanding how increased uptake in new technologies will participate in FCAS markets, any regulatory framework for frequency control must remain technology neutral to allow innovative new services to bring costs down while providing the greatest benefits to FCAS providers.

AGL considers that on the current economic forecasts, some of the options for providing fast frequency response are batteries (grid scale and potentially small scale), pump storage hydro schemes and demand response. Frequency issues could also be addressed by removing the disincentives to use fluctuating loads for demand response. Currently there is a greater incentive to use flat loads for demand response. The calculation methodology de-rates fluctuating loads, even though it could reduce its output (provide maximum demand response) for a short period of time.

Certain energy appliances and sources may be well suited to FCAS market participation. For example, air conditioning as a demand response source is very well suited for FCAS as the cooling cycle is interrupted for such a short time that the user is not even aware that the air conditioner has dispatched and is not inconvenienced. Electric vehicles are also well suited to participation in the market, due to the large amount of energy they can draw and release in the grid when connected on a large scale.

It would also be possible for grid-scale wind and solar assets to provide lower FCAS. Under the current framework it is not economic for these assets to provide raise services because there is no compensation for leaving generation head room.

Under a competitive market framework, these technologies would be able to provide these services if adequate price signals were provided. We anticipate that as markets develop, other innovative technologies will also enter the market.

AGL considers there should be further analysis of the need for a faster frequency response and supports reviewing the FCAS settings to make sure it reflects the current generation and emerging trends. For example, while adding a new shorter timed FCAS may seem like the simplest option, it could add more complexity to the current system and affect the value stacking of assets that can provide FCAS, as well as the liquidity of the market. It could be found to be more appropriate to simplify the FCAS markets, for example like New Zealand's market structure of Fast Instantaneous Reserves (FIR) and Sustained Instantaneous Reserves (SIR) markets.

AGL is actively involved in demonstrating the ability for new technologies to provide in frequency control services, and collecting valuable data about the viability of these technologies to participate in future markets:

- The 30 MW Dalrymple battery in South Australia is currently under construction and is expected to be operational in early to mid-2018.
- The virtual power plant in Adelaide will involve one thousand smart, connected energy storage devices installed behind-the-meter at homes and small businesses. When aggregated, the batteries will act like a 5 MW energy asset. Over the next three years the project will demonstrate at a commercial scale the value that DER can provide (among other things) for synthetic inertia and frequency balancing services.

The value of this data will be to inform policy-makers of optimal solutions to frequency provision by providing real costs and information on any barriers to participation that may be technical, regulatory, or physical.

Distributed energy resources

AGL considers it vital that any market reforms take a technology neutral approach to achieve the lowest cost outcome for consumers. This will involve identifying and removing any barriers to entry for new technologies, for example to allow aggregators to fully participate in providing frequency control services.

AGL has some concerns with the existing connection framework, which can act as a disincentive for consumers to install optimally sized DER and which may prevent aggregators from providing network services when it is most needed.

Customers expect to be able to easily connect new distributed technologies behind-the-meter. However, there are different application processes and technical criteria applying across different distribution networks. These cumbersome and lengthy application processes create a barrier to the easy connection of new distributed technologies. These challenges were recently highlighted in the joint ClimateWorks and Seed Advisory report 'Plug & Play: Facilitating grid connection of low emissions technologies'.[1]

AS4777 and the DNSP connection standards restrict both the size of DERs that can be easily connected and how they are operated. These standards were largely designed with uncontrolled solar PV inverters in mind and do not take into account the ability of orchestrated DERs such as energy storage and load control to both moderate the impact of solar PV generation on transmission and distribution grids and to provide firming capacity, ancillary services and network stability services. In particular, DNSPs consider the rated capacity of power control electronics rather than the potential to positively or negatively impact the grid and so impose arbitrary limits on the number and capacity of inverters or other generators that can be connected at a single site.

For example, in some distribution networks, a household may be able to install individual 5kW solar system and a 5kW battery, but the system as a whole is limited to exporting 5kVA.

Another concern is that the same connection requirements are applied to batteries and solar PV, without recognising the benefits of batteries or of combined systems. For example, in April 2017 a new AS4777 was introduced, applying to new installations. It includes more stringent disconnection requirements and as a result:

- Combined with the high grid voltage seen in certain jurisdictions, there is a higher rate of inverter disconnection than under the previous regime. This could prevent storage inverters from participating in frequency or demand response programs, and may limit consumer protection in such programs.
- Also, recently installed storage inverters will disconnect from the network before older PV systems disconnect from the network. The batteries could otherwise be ‘soaking up’ the electricity from the PV system, so disconnection of the battery can cause further grid issues.

[1] ClimateWorks and Seed Advisory, ‘Plug & Play: Facilitating grid connection of low emissions technologies’, Consultation Summary Paper, February 2017, https://climateworks.com.au/sites/default/files/documents/publications/climateworks_seed_plugplay_consultation_report_final_20170228.pdf

A better approach would be to consider the site behind the meter as a holistic system that can interact with the wider network. For example, if the grid segment is experiencing high voltage it is better for the wider network if individual consumers are incentivised to lower the grid voltage through orchestration, for instance through the charging of batteries, the activation of loads, or the injection of reactive power from solar inverters.

Customers should be incentivised to provide system security services and fairly compensated. These incentives should be market driven and reflect the fair value for the services provided. Mandatory requirements, whether for the DNSP's benefit or the wider network, compromise the investment that the customer has made by curtailing energy production.

Whilst individual DERs may not be as 'firm' as large-scale generators, there is a high probability that if a segment of the fleet is not available then assets in other locations are available. It would be the role of an aggregator to manage the availability of distributed assets and to bid their services into the market in a way that reflects what can be delivered with certainty. The aggregator would develop statistical tools to predict fleet availability as part of its business. AGL notes that the "virtual power plant" in SA will provide some experience on this over the coming years.

Another issue is the AEMO requirement for measurement and verification of output every 50ms for the actions undertaken to stabilise frequency. For DER, this requires special hardware to be included in the system, which adds additional cost. AGL considers this is unnecessary for DER for the following reasons:

- It is currently difficult to source DER devices that can provide measurements at 50ms speed.
- One second data is widely used in other jurisdictions (such as EU and NZ) and AEMO has not adequately explained why 50ms data is necessary for DER.
- As the number of DER increases, it will result in a huge amount of data being transmitted to AEMO. It is unclear whether AEMO will be able to easily process that volume of data and react immediately to changes in the network.

It will also be necessary to investigate and determine how to manage conflicts between local and system wide priorities. For example, under the current rules if the local voltage is high during a raise event, any attempt to dispatch DER may result in the DER disconnecting from the grid and failing to provide the service. Whilst this can be factored into the availability function discussed above it may result in reduced opportunities for participation by customers.

Finally, AGL notes that the increased penetration of DER may result in load shedding becoming less effective for system security management. When an area is shed, it will include the shedding of distributed generation, which is helping to maintain the supply and demand balance.