Mr John Pierce
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000
Lodged via www.aemc.gov.au

Friday, 10 February 2017

Dear Mr Pierce,

RE: System Security Market Frameworks Review (ref EPR0053)

ENGIE appreciates the opportunity to comment on the Australian Energy Market Commission (AEMC) System Security Market Frameworks Review Interim Report (Interim Report).

The interim report does not identify the extent to which the points raised in industry submissions to the previous consultation paper have considered, or if they have been considered at all. In light of this, ENGIE is inclined to firstly refer back to its submission to the previous consultation paper, and highlight the key points made in that submission:

- A rate of change of frequency (RoCoF) standard would appear to have limited application since it would only apply to protected events, and would lead to reduced utilisation of the protected interconnector.
- Rather than attempt to define a RoCoF standard, the security objective could be expressed as a requirement to maintain the post contingent power system frequency to within the frequency operating standards, taking into account the assessed level of frequency response to disturbances inclusive of inertia and frequency control services.
- The proposed inertia service could be expanded to incorporate a suite of 'flexibility' services, that would deliver a wider range of system benefits both before and after a contingency event, and therefore provide a better balance of costs and benefits.

ENGIE is broadly supportive of the framework that the AEMC have proposed as described in figure 1 of the interim report as it provides a good overall picture of the system security drivers and control actions. ENGIE notes that the very first 'box' in the framework diagram is labelled "Event that the power system must be able to survive". Given that the interim paper also outlines the potential to introduce a new category of contingency event known as a protected event, ENGIE suggests that the framework should recognise this. For example, the “Operating restrictions” that apply to a credible contingency event would be different to those that apply to a protected event.

The interim report includes discussion on the effect of reducing levels of power system inertia in South Australia due to the increase in non-synchronous generation, and notes that an unexpected loss of the Heywood interconnector at a time of low inertia could result in an insecure power system in South Australia.

To summarise, ENGIE is supportive of proposals to introduce a new commercial arrangement for providing inertia, but continue to have concerns that it may not provide a sufficiently strong financial driver to change the commitment decision of existing synchronous generators, and if poorly implemented, could lead to other synchronous generators being driven to shut down. The decision to commit synchronous capacity is a significant one that would require a substantial amount of money to be justified. It is questionable whether the value placed on inertia, which has in the past had no value placed on it at all, should suddenly be priced so highly that it will be sufficient to change synchronous generator commitment decisions.

Nevertheless, ENGIE has set out below some ideas for consideration by the AEMC in its deliberations on this complex matter.

The interim report notes that there are two pre-contingent actions that could be taken to improve the post contingency security:

- Constrain the power system to minimise the contingency size, and/or
- Increase the level of inertia

ENGIE agrees that either of these approaches could achieve the objective of improving the post contingent security, however each introduces new issues to be considered. For example, constraining the power system to reduce contingency size will inevitably reduce the overall efficiency of the power system since the constraint will be preventing what would otherwise be an efficient power flow. ENGIE would therefore prefer to see this option only used as a last resort.

Increasing inertia is obviously desirable, but the means by which this is achieved, and the costs might be ineffective or prohibitive. ENGIE understands that new technologies are being developed that have the capability to provide synthetic inertia, and that these might prove to be well suited to commercial procurement at some point in time. In the immediate to short term however, the most likely source of inertia is from existing synchronous generators.

The National Electricity Market (NEM) energy only market design means that for a generator to be able to meets its start up and running costs, it needs to not only be online, but it needs to be generating in order to sell energy to the market and hence, receive an income. Although there are proposals to introduce new payments for inertia, ENGIE has a concern that the amount of money that would be needed to encourage a generator that would otherwise not be running, to come online and remain online, is likely to be very high. To compound this problem, when a generator is incentivised to come online, it will need to operate to at least its minimum operating level, and so it will cause the wholesale energy price to fall. This may prompt other generators that were previously online to decide to come offline, meaning that the inertia may again fall below the desired level.

In circumstances where there is a large amount of non-synchronous generation online and inertia is low as a result, the act of bringing a synchronous generator online to provide inertia will mean that some generation needs to be reduced to ‘make room’ for the inertia unit. The question then becomes which generator(s) should be required to reduce. If it is left to the normal NEM pricing signals, then it will be the generator in the region (or neighbouring region(s) connected via non-binding interconnectors) with the highest marginal price. All else being equal, this is likely to be a synchronous generator (most likely a gas fired generator). Importantly, it is unlikely that the NEM pricing mechanism would require a non-synchronous generator to be the one to back down and ‘make room’ for the inertia unit.

In the above scenario, the marginal synchronous generator that is backed down to make room for the inertia unit might decide to de-commit, since its NEM revenue has been reduced. If this occurs, then the benefit of bringing on the inertia unit has been lost.

ENGIE believes that this inevitably leads to the conclusion that if it is necessary to reduce one or more generators to make head room to bring an inertia unit online, the most appropriate generators to reduce are the non-synchronous generators that are providing no inertia. This outcome could potentially be achieved through one of two possible mechanisms:

1. Apply a set of constraint equations to the non-synchronous generators in the relevant region which shares the reduction across them all according to a pre-determined allocation method
2. Introduce a financial mechanism that calculates a spot price for inertia and pays all online generators for providing inertia, and recovers the money from the non-inertia providing generators in proportion to their energy output.

ENGIE favours option two since it allows the non-inertia providing generators to decide whether they will continue to generate and pay the consequent inertia price, or reduce their output to minimise their exposure to the inertia cost. If the non-inertia generators all took the decision not to reduce their output, then the spot price for inertia would likely increase quickly, creating a stronger signal for the non-inertia generators to reduce.

Creating an incentive for non-synchronous generator to reduce to make room for synchronous generators may appear controversial, as it might seem to run counter to the general desire to increase the amount of renewable generation in Australia. However, ENGIE suggests that this signal would only have a material impact in circumstances where the total volume of non-synchronous generation had increased to the point that the available inertia was insufficient. This mechanism also provides an incentive for non-synchronous generators to make available a synthetic inertia facility, which would allow them to avoid exposure to the inertia cost mechanism described above.

ENGIE notes the interim report has suggested that the requirement for inertia can be divided into two components – system security and market benefits. The interim report provides an example of the Heywood interconnector being treated as a protected event whereby the contingent loss of the interconnector needs to be considered. In this circumstance, ENGIE can see how a trade-off exists between the power flow over the protected interconnector, and the amount of inertia available.

This co-optimisation between the protected interconnector flow and inertia procured needs to be considered carefully. It may be likened to the existing co-optimisation within NEMDE between frequency control ancillary service (FCAS) and energy. However, whereas the FCAS co-optimisation seeks to optimise an individual generators position in terms of the trade-off between its supply of energy and FCAS, the trade-off between the flow on an interconnector and the provision of inertia could potentially lead to unintended outcomes. For example, a provider of inertia in South Australia could set its offer price for inertia at a high level to avoid further import into the region, which may be to that participant's commercial advantage but detrimental to the overall market. In other words, introducing a trade-off that links one market entities outcome with another needs to be carefully considered.

Where an interconnector is not considered to be either a credible or a protected contingency event, then AEMO does not need to cater for the loss of this interconnector, and the trade-off with inertia does not arise.

It is conceivable that under unusual system conditions, a large block of generation or load may be subject to a single credible contingency. In this circumstance it is again conceivable that the contingency size may be traded off against the amount of inertia available.

In consideration of the above, it seems that the only 'system normal' situation where the contingency size could conceivably be traded off with the amount of inertia is if the protected event classification was introduced and applied to an interconnector such as Heywood. If this is the case, then it would seem that a consequence of deciding to apply the protected event classification to a particular interconnector will be that the value of that interconnector will be diminished. This detrimental outcome could be reduced to some extent if the frequency standard applicable to the contingent loss of a protected (as opposed to credible) contingent loss of an interconnector, were more relaxed. For example, the frequency operating standard (FOS) currently defines the post contingency frequency following a *separation event* as being 49.0 Hz, with *separation event* defined as "a credible contingency event in relation to a transmission element that forms an island" (emphasis added). ENGIE would suggest that the FOS be revised to include consideration of a separation event due to a contingent loss of a protected interconnector, and apply a more relaxed frequency standard. This would be consistent with the general aim of introducing a protected event classification that sits somewhere in between a credible event (for which the most onerous standards should apply) and the non-credible contingency event (for which no obligations apply).

Setting a new system security standard for RoCoF

The issues paper in section 4.2.2 outlines the possibility of introducing a new system security standard to set a maximum value for RoCoF. It is noted in the issues paper that establishing a maximum value for RoCoF acts as a means to determine either the amount of inertia to procure, or the extent to which the system should be constrained for a given contingency event. As set out in our previous consultation paper, ENGIE is not convinced that a standard for RoCoF needs to be established at all. The existing FOS is sufficient for AEMO to decide whether they need additional inertia service. For example, as the inertia on the power system reduces, AEMO can assess the impact of the resultant increase in RoCoF, and whether the post contingent frequency will change more quickly than can be managed by the available FCAS sources. If AEMO determine that the post contingent frequency cannot be managed adequately, then AEMO can then seek to procure additional inertia, or constrain the power system to reduce the contingency risk.

ENGIE therefore favours an approach that does not require a RoCoF limit to be established by the Reliability Panel, or by AEMO but uses the existing FOS to enable AEMO to establish the extent to which additional inertia is required.

Tolerance of the system

The interim report outlines a number of considerations relevant to the need for generators and loads to be able to withstand RoCoF up to a certain level without causing them to become unstable or trip. This will be particularly important for any equipment that is providing an inertia service through any new market or contract arrangement.

As noted in the interim report, it will be difficult for many of the existing generators to be able to accurately establish exactly what their RoCoF tolerance might be, other than through trial and error. A prudent approach is therefore suggested which does not retrospectively apply stringent standards on existing plant that they are unable to achieve. On the other hand, any plant that is seeking a payment for inertia under a new commercial mechanism should be required to establish that its equipment is capable of withstanding a RoCoF event at least to the targeted level.

ENGIE trusts that the comments provided in this response are of assistance to the AEMC in its deliberations. Should you wish to discuss any aspects of this submission, please do not hesitate to contact me on, telephone, 03 9617 8331.

Yours sincerely,

Chris Deague
Wholesale Regulations Manager