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

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 Directions Paper (directions paper).

The directions paper presents the AEMC's proposed approaches to addressing the two key systems security issues identified in its interim report published in December 2016: the management of frequency and of system strength in a power system with reduced levels of synchronous generation.

Key point

ENGIE is supportive of the proposed approach of implementing an immediate package of reform, followed by a subsequent package, which builds on the components of the immediate package. This approach should be able to introduce interim improved methods for the procurement and management of power system inertia and system strength prior to the peak electricity demand periods of the upcoming summer.

Nonetheless, ENGIE is concerned that the proposed immediate package has the potential to result in transmission network service providers (TNSPs) implementing network based, long term solutions to the inertia and system strength requirements, and therefore leave no subsequent opportunity for more economically efficient solutions to be introduced in the subsequent period.

ENGIE does not support mandating that new non-synchronous generators are capable of providing fast frequency response (FFR) services. If there is a clearly defined requirement for FFR then this will provide an incentive for all technologies to offer the service. Mandating capability on all new generators imposes an unnecessary cost imposition.

These comments are expanded in the remainder of this submission.

Inertia procurement

The directions paper considers four broad options for the procurement of inertia and system strength services: market based solutions, Australian Energy Market Operator (AEMO) contracting, TNSP contracting and generator standards.

The directions paper concludes that a market based approach, where inertia and system strength procurement are incorporated into the National Electricity Market (NEM) dispatch and pricing arrangements, is unlikely to be practical. The difficulty with this approach is in large part because inertia and system strength provision by generators is related to their commitment status – a binary variable – and not to their dispatch output as is the case for frequency control services. This binary decision cannot be easily incorporated into the NEM linear optimisation algorithm, and so unless there is a decision to move to an integer optimisation algorithm in the NEM, it seems unlikely that a market based solution will be viable.

The directions paper proposes that TNSPs take on the responsibility for procurement of inertia and system strength services, with AEMO playing a role in terms of establishing the level of service required, and confirming that the proposed service providers are viable. The directions paper also proposes to introduce new generator standards for proponents of new non-synchronous generating technologies.

ENGIE supports contract based procurement of inertia and system strength services, as the binary nature of their delivery (as mentioned above) does not lend itself to co-optimisation within the existing NEM algorithm. However, ENGIE is strongly of the view that the TNSPs are not the appropriate agency to carry out this procurement task for the following three main reasons:

1. as regulated monopolies TNSPs are likely to favour regulated solutions that could lock out competitive options;
2. TNSPs are skilled in the planning and operation of transmission networks, not the power system – there is a distinct difference the should be recognised; and
3. the proposed reliance on the existing NSCAS[1] clauses in the rules goes beyond the purpose of these clauses.

Looking at item one of the above list, ENGIE notes that TNSPs operate, not in the competitive sector of the electricity industry, but as regulated monopoly service providers. TNSP businesses are structured towards establishing and maintaining regulated transmission network assets, and they have little need to contend or interact with the competitive market elements of the NEM.

Although the current regulated investment test for transmission (RIT-T) does incorporate a market benefits test, it is a difficult task for regulated TNSPs to assess and understand competitive drivers on NEM participants, let alone forecast how such drivers might play out over the medium to longer term.

It seems likely that when faced with the task of ensuring that a certain level of power system inertia is maintained, the TNSP will be pre-disposed towards a network solution, such as the installation of a synchronous condenser.

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[1] Network Support and Control Ancillary Services

Such an approach would have the effect of locking out potential future competitive options such as shorter-term contracts for delivery of inertia services.

The directions paper suggests that it is better for the TNSP to be responsible for the contracting of both inertia and system strength since this will avoid the potential risk of AEMO contracting one service for inertia, and the TNSP another service for system strength, when in fact, a single service provider may have been able to meet both requirements. This potential risk can be avoided by AEMO by understanding both the global (inertia) and the local (system strength) requirements, and choosing the most economic overall solution.

The directions paper suggests that TNSPs could potentially use the RIT-T process to competitively procure inertia and system strength services. ENGIE believes that the procurement of inertia through a RIT-T process would potentially go beyond the bounds of the rules definitions of the purpose and scope of the RIT-T. For example, the RIT-T applies to proposed expenditure that relates to augmenting the transmission network. Whilst it might be arguable that system strength services are an integral component of the transmission network, it is very difficult to argue the same for inertia services. Inertia and frequency control services are related to supply – demand balance across the entire power system, which incorporates generators, loads and networks.

This then brings us to the second point in the above list – that TNSP skills and expertise do not extend to power system management. The management of power system frequency and inertia involve real time consideration of generation and loads across the entire power system, and not just the network elements within a certain region. It is therefore well beyond the scope of a TNSP to have the full grasp of all of the relevant variables to be able to manage these concepts.

ENGIE acknowledges that the AEMC have proposed that AEMO would determine the inertia requirement, and that the TNSP would then provide the service subject to AEMOs approval that the proposed service provider adequately meet the necessary power system requirements. This shared responsibility raises the potential for duplication of effort as well as some important considerations falling between the cracks. These issues would not arise if the agency best placed to establish the inertia requirement and operate the service had the appropriate accountability. That agency is AEMO, not the TNSPs.

The third point that ENGIE would like the AEMC to consider regarding inertia provision is the intended reliance on the existing NSCAS provisions within the rules. The definition of *NSCAS need* in the rules uses the phrase “service required to maintain power system security and reliability of supply of the transmission network”. The use of the term “transmission network” is significant, and is in contrast to all clauses in the rules that refer to frequency control, where the term “power system” is used.[2]

One final comment on the proposed framework for the procurement of sufficient inertia services relates to the suggestion in the directions paper that the inertia required to maintain RoCoF within given limits can be divided into

[2] For example, refer to rule definitions for frequency operating standard and all of the frequency control ancillary service definitions (eg fast raise service) – these all refer to the ‘power system’, and not to the ‘transmission network’. ENGIE understands this to refer to the fact that the power system is a more general term which is inclusive of all network, generation and load elements, whereas the term ‘transmission network’ is a more restrictive term to refer specifically to the transmission system, and not the other elements.

two components being for: “minimum system threshold” and “market benefits”. ENGIE is not convinced that inertia can compartmentalised in this way. The requirement for inertia is a function of the RoCoF target and contingency size, as expressed through the following equation:

$$I = (25 \times \Delta P) / RoCoF$$

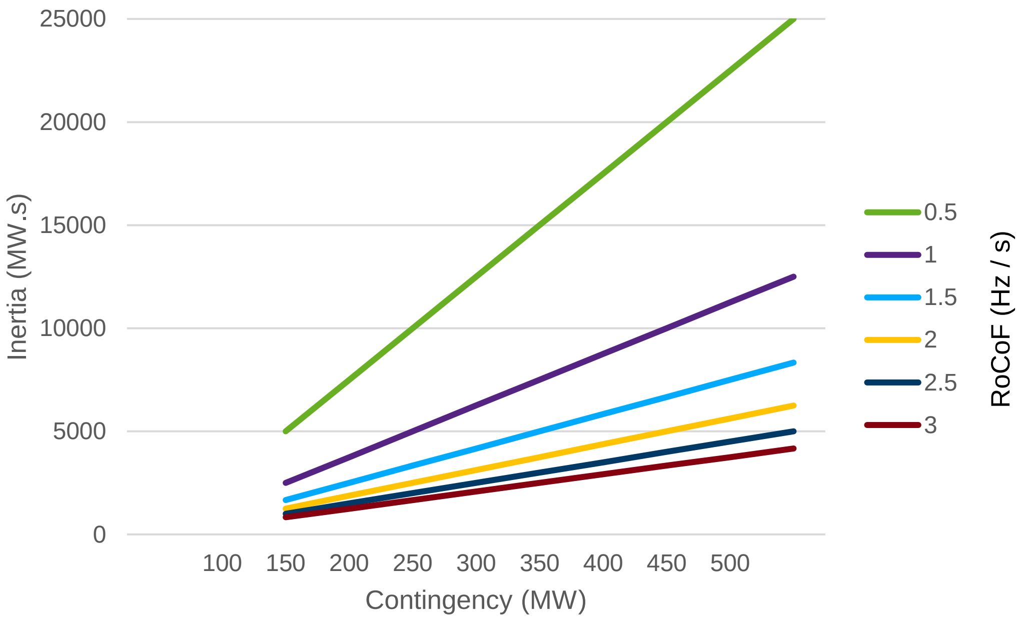
Where

I = level of required inertia (MW.s)

ΔP = contingency size (MW)

RoCoF = rate of change of frequency following the contingency

The variation in inertia for various combinations of contingency size and RoCoF is shown in the following graph.



It is not clear to ENGIE how a ‘minimum system threshold’ can be identified from this range of possible inertia requirements. Even if a simplifying assumption is made that for example, the post contingency RoCoF must be no greater than 1 Hz/s, the above graph shows that the possible inertia requirement can still vary from approximately 2000 to over 12500 MWs, depending on the contingency size.

If the concept of a minimum system threshold is to become a component of the power system security framework, ENGIE suggests that the AEMC and AEMO need to provide a clearer explanation of how this threshold is established.

In summary, ENGIE supports an immediate approach that seeks to ensure that sufficient inertia is in place for the upcoming summer period, and recognises that interim measures may be needed to achieve this timetable. ENGIE believes that AEMO are the most suitable agency to determine the required amount of inertia service needed, and to then seek to procure this service through a tender and contract process.

The tender process conducted by AEMO could be open to participation be existing synchronous generators and to TNSPs. Presumably, TNSPs could offer the provision of inertia by installing synchronous condensers. Unless other participants were able to offer sufficient levels of inertia at a total cost below that offered by the TNSP, then AEMO would then offer the contracts to the TNSP. This in effect would provide a safety net, to ensure that the overall cost of inertia was economic.

System Strength

The directions paper outlines the proposal to amend the rules to clarify that NSPs should be responsible for maintaining an agreed minimum short circuit ratio to connected generators. Generators would continue to be required to meet their registered performance standards above this agreed level. Where entry of a new generator causes short circuit ratios to be breached for one or more existing generators, the NSP would recover the costs of remedial actions from the connecting generator on a "causer-pays" basis.

The directions paper notes that this principle would not apply to generator retirements that cause system strength to fall below a minimum level. In this case, any resulting works would be undertaken by the NSP as a prescribed service (customer funded).

ENGIE is broadly supportive of this approach as it strikes a reasonable balance between cost efficiency and practicality.

New generator obligation

The directions paper has proposed that new non-synchronous generators should be obliged to have the capability to provide FFR services so that they are able to provide the services - but the rules would not require that they provide the service.

ENGIE does not support mandating that new non-synchronous generators be capable of providing FFR services.

The existing rules contain a number of technical standards[3] that connecting generators are required to meet in order to register in the NEM. These technical standards are required to preserve the integrity of the power system by ensuring that the connecting generator does not degrade system security. There are no rule obligations for connecting generators to have the capability to participate in the voluntary frequency control markets – rather these markets provide incentives for generators to have the ability to participate.

ENGIE believes that the proposed obligation on new non-synchronous generators introduces an overlap of market incentives and regulated outcomes. Either generators should be incentivised to participate in commercial arrangements, or they should (if markets are found to be ineffective) be regulated – but not both.

[3] Refer to rules clause S5.2.5.

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