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Mr Ben Barr
CEO Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2001

19 May 2020

Dear Mr Barr,

Thank you for an opportunity to respond to the Investigations into System Strength Frameworks in the NEM review (EPR0076). We commend the AEMC for its thought-provoking discussion paper on this important topic.

System strength is one of the major challenges for transition of the NEM to a low-carbon power system. System strength is one of three main issues contributing to the decline in new renewable energy connections in recent times, the others being congestion and marginal loss factors.

The system strength framework as it currently stands is not working as intended, and is providing a major deterrent to investment both for new connections and upgrades of existing generation, particularly for inverter-based renewable energy generator. This is occurring in the context of an aging fleet of thermal generators, a substantial portion of which will retire in the next 10 years. Substantial new generation is needed to replace the retiring plant and this should mainly come from low CO_2e emissions plant. If this investment is choked the reliability of supply and the price of supply in Australia will be adversely impacted.

System strength is a term coined to cover a range of issues that arise when synchronous generators, which are voltage sources, are withdrawn from the power system and replaced with generators that are essentially current sources. Synchronous generators oppose changes to voltage caused by power system disturbances by injection of reactive power. The effective source impedance of a synchronous generator following a large voltage disturbance is initially very low (subtransient impedance) for a short period and increases to its steady state value after a few seconds. This gives rise to fault current, which is transiently higher than the steady state current. This is termed fault current, and the current that flows for a three-phase fault at the terminals of a synchronous machine is called the fault level.

In the current system strength framework, a system strength service is defined in terms of fault current. This is a relatively easy parameter to quantify and measure and therefore convenient to commoditise, but it is not necessarily the essential service that is system strength. Protection systems using existing technology need a certain amount of fault current to discriminate between a fault condition and normal operation to clear faults but, otherwise, fault current is a destructive biproduct of an abnormal power system condition. We need to be very careful that our use of fault current as a surrogate for system strength does not lead to incentivising the wrong behaviours. We consider that system strength is more closely related to the voltage source, and its ability to produce a sinusoidal reference voltage and maintain stable sinusoidal voltages both near to its terminals and further into the network. This might also be described as the ability to provide a stiff grid.

The current system strength framework is divided into two parts, which the AEMC describes as the:

- Minimum system strength and
- "Do no harm" components

Under the Minimum system strength framework, AEMO sets minimum fault levels at certain nodes in the network, above which the power system should be able to operate stably and securely. This should take into account the dispatch patterns of generation in the area. The concept is that if the fault levels go below this level the relevant TNSP is required to provide a system strength service to remove the deficit.

In practice the minimum system strength framework has not worked effectively. We find several issues with it, from our own experience:

- The minimum system strength level can be set too low.
- The minimum system strength levels are not updated to account for new generation in a timely manner.
- The declaration of a system strength deficit is reactive. It is not declared until the fault levels have gone below the minimum level, and even once it is declared there may be some years before anything is done to alleviate it.
- The location of the system strength node is arbitrary.

In the case of North Queensland, the minimum system strength fault level was set at a time before the TNSP or AEMO had a PSCAD model of the system. The location of the fault level node was established at Nebo, for the whole of North Queensland. As far as we are aware every non-synchronous generator connected in north of Nebo, including Sun Metals, which was registered within a month of the System Strength Rule taking effect, has been determined to have an adverse system strength impact. This clearly indicates that the minimum system strength level was set at a level that was too low from the outset. The actual process to determine the minimum system strength is also not transparent.

In April 2020, two years after the initial 2018 assessment the Nebo node was replaced by a Ross node (approximately 330 km further into North Queensland than Nebo) and a fault level shortfall of 90 MVA declared. This did not remove the requirements on generators to mitigate an adverse system strength impact arising from the initial level of minimum fault level set. Very few new generators have connected in North Queensland, since the introduction of the system strength framework, despite the area having a very high-quality solar resource. The minimum fault level at Nebo was not updated between July 2018 and April

2020. This suggests that initial studies did not include a number of North Queensland non-synchronous generators that were not connected at that time, and a PSCAD model of the area was not available, and the minimum fault level was not reviewed subsequent to the connection of generators in that area, until the studies undertaken for the April 2020 report.

The use of fault level for setting minimum system strength levels and to specify a deficit in system strength is, we believe, part of the weakness of the current arrangements. The lack of transparency and predictability is a further issue from the perspective of an investor.

The second part of the system strength framework 'Do no harm' applies to new generator connections and to generator seeking to upgrade their plant under the process defined in clause 5.3.9 of the rules (the 5.3.9 process). Under the 'Do no harm' process a connection application is assessed by the NSP to determine if there is a potential adverse system strength impact first under a screening process (the Preliminary impact assessment (PIA)) and if this indicates a possible adverse impact on system strength then a full impact assessment (FIA) is undertaken by the NSP using a PSCAD model of the system. A connection applicant is required to submit a system strength mitigation strategy with the application to connect but has no information available to scope or size the mitigation strategy. The same arrangement applies for a 5.3.9 application. The PIA does not provide any useful information for this process. The connection applicant is unable to optimise the proposed solution in any way and this results in a highly inefficient and slow process. In addition, the current Rules have been interpreted by TNSPs and AEMO to prevent connection applicants from accessing all but the most limited information about the results. As with system strength, there is a significant issue for investors with the predictability and transparency of the process.

In practice, system strength manifests as an oscillatory stability issue, typically a lightly damped or sustained oscillation in the range of 7-10 Hz occurring following the trip of a line (for example, following clearance of a fault). Like electromechanical inter-area modes of oscillation found in synchronous plant, these oscillatory stability modes occur because of the interaction between generators' control systems. In this case it is between the control systems of the grid-following inverters. Control system interactions can generally be managed by tuning the controls to damp the oscillations. This has been very difficult to achieve in practice for the following reasons:

1. Generators do not have access to the detailed model of the power system in PSCAD that would allow them to tune the control systems (transparency issue). The PSS/e model available to generators does not contain the detail of the inverter controls that would exhibit the oscillatory behaviour demonstrated on the PSCAD model.
2. Tuning individual generating systems independently of one another will not result in an optimal set of parameters for damping of the whole system. This needs to be done as a coordinated effort across all the generating systems participating in the oscillation and the power electronic network devices (like SVCs and statcoms) in the area.
3. The technical standards for generators (especially S5.2.5.13) drive particular tuning strategies on individual generators that are sub-optimal for achieving the best stability outcomes across a set of generating systems. The rules around S5.2.5.13 need to be changed to allow tuning for best power system outcomes. Faster response is not always better, especially in weak grid conditions.

4. Gradually over time the inverter and power plant controller firmware has been improved as various issues have been identified, usually during the connection process. However, it is very time-consuming, expensive and, because of the system strength framework, risky for a generator to upgrade firmware (a 5.3.9 process is required), even if it improves the stability performance of the plant.
5. In addition, there is no process under the current Rules that facilitates the coordinated updating of firmware and settings to optimise performance of a group of generators even though this would be the most cost-effective way to improve system strength. On the contrary, generators face the unpredictable and costly 5.3.9 process, effectively a strong disincentive to co-ordinate settings.

The stability of the grid can be reduced as more non-synchronous generators connect. The stability issues are exacerbated if control systems are not coordinated and optimised for that part of the system. There are particular issues with grid-following inverters that make them particularly susceptible to this problem, the main one being that they are current source devices, and when they inject into a weak grid the voltage at the connection point becomes less stable. The more inverter-based plant connected the worse the system strength problem becomes. Generators connecting later face higher hurdles than generators connecting earlier, so the "do no harm" effectively creates a queuing process. This has the following effects:

- It increases the risks for connection, because a generator can be almost at the point of executing a connection agreement, then another plant achieves this milestone and the whole assessment process begins again. The process restarts from a worse point for system strength. Without access to the detailed models or ability to retune neighbouring plant, the generator is often forced into very expensive blunt solutions such as synchronous condensers to fix the problem.
- It creates a deterrent for parties to work together to collaborate on solutions or share capital costs for mitigation works.
- It makes upgrading existing plant increasingly costly and risky over the life of the plant, discouraging innovation and performance improvement.

The inadequacies of the minimum fault level part of the framework, especially failure to set an appropriate level and its reactive nature, mean that the problem is merely transferred from the TNSP to the generator to fix. Lack of transparency and access to models make it highly likely that any solution that the generator comes up with will be sub-optimal. Multiple generators installing equipment independently will not result in an efficient outcome for the NEM, or lowest cost connection for the generator. Higher generation costs result in higher consumer costs.

Many of the issues raised here can be fixed with relatively simple Rule changes. Some are more complex and need to be considered in the context of a power system that needs to transition away from carbon-emitting plant to renewable energy. In Queensland we do not have the luxury of ample hydro resources, so most of our generation will be from solar and wind, probably complemented by battery storage, and possibly some pumped-storage hydro, and a substantial part of our generation will be on consumers' rooftops. This means we must develop a framework now that will work without relying on large synchronous machines. All this is required while keeping the cost of electricity at a reasonable level. Even though the technology in grid-following inverters has improved markedly over the past couple of years, there will be a limit to how much additional grid following plant can be connected without additional support from voltage source generators. We must ensure that the system strength framework encourages the development of these voltage source generators, while enabling the transition to a low carbon power system. This includes not unduly favouring incumbent generators and not unnecessarily constraining or disincentivising renewable generation. In the meantime we should focus on getting the most out of our existing power system. This can be facilitated by making changes to the Rules that support what the AEMC's discussion paper calls "passive system strength" improvements. The changes should include mechanisms that allow NSPs and participants jointly to optimise stability of the power system, in an efficient way, that does not impose unnecessary costs and risks on generators.

Please consider this submission, along with our response to the AEMC's questionnaire.

Kind regards

Kathy Danaher

Executive Director and Chief Financial Officer

Sun Metals Corporation

AEMC

Investigation into system strength frameworks in the NEM

STAKEHOLDER SUBMISSION TEMPLATE

The template below has been developed to enable stakeholders to provide their feedback on specific questions that the Commission is interested in due to the discussion paper. It is designed to assist stakeholders provide valuable input on those questions the Commission is interested in. However, it is not meant to restrict any other issues that strakeholders would like to provide feedback on.

SUBMITTER DETAILS

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CHAPTER 2 – KEY ISSUES WITH THE CURRENT SYSTEM STRENGTH FRAMEWORKS

Section 2.3 – Key issues of the minimum system strength framework	
1. Do stakeholders agree with the AEMC's assessment of the issues of the minimum system strength framework?	It appears from the Discussion Paper that the Commission is concerned about the potential for the minimum system strength framework to result in larger than necessary determination of the system strength deficit. Our view is that the main problem is that the process takes to long to identify a shortfall and that the minimum fault level is not set correctly nor updated frequently enough. The demonstrable consequences are to deter or delay the connection of renewable generation, and deter or delay modifications of existing generation. Arguably, the prolonged constrained operation of a number of renewable generators in the NEM is also a consequence of the failure of the minimum system strength framework to identify and alleviate system strength issues in a timely manner. The consequence of providing more system strength service than required is only to provide a bit more time before the system strength once again becomes problematic for new connections and existing plant. We therefore consider the lack of service much more costly to the industry than over-provision of the service. We agree with the Commission's description of the minimum system strength framework as being reactive. The consequence of this can be seen in the significant effect on generators in the West Murray network, where a system strength impact clearly existed for some time prior to declaration of a system strength shortfall.

	System strength is more of a stability issue than a fault level issue, and adverse system strength impacts are defined in terms of stability impact on the power system, not fault level. Use of fault level is therefore only a surrogate to define minimum system strength level. In practice as more inverter-based generation is connected in an area, the interactions between the voltage control systems become less stable, as more reactive power is injected into a system having the same impedance, but the fault level is virtually unchanged. The minimum fault level for which the system remains stable for a set of contingency events and outages increases as more inverter-based generation is connected over time, without any reduction in synchronous generation, all else being equal (effective short-circuit ratio effect). Therefore if minimum fault level is used as a surrogate for minimum system strength for which the system is stable, it should be adjusted for every new inverter-based generator connection. Perhaps, in this way, the system strength deficit might be triggered in a more timely fashion. The trigger for a system strength deficit to be declared could be set when the difference between the actual fault level and the minimum fault level (adjusted as previously described) was less than some reasonable threshold. This would have the added advantage of providing some margin for providing additional resilience in the power system response to non-credible contingencies. A system strength shortfall (or rather a system stability impact) could be anticipated in advance if typical inverter-based renewable generator models were used to examine stability for a range of contingency events, considering connection enquiries, or possible renewable generation hubs. However, the current Rules seem to require an actual shortfall, rather than allowing NSPs to address the problem in advance. Wating until a generation connection application is made or the generation becomes a "committed project" to consider it in a system strength shortfall assessment will not address the problem, as it simply transfers the problem as an obligation on the generator, rather than addressing the underlying system deficit. Uncoordinated, piecemeal solutions generally result in higher overall cost for the industry. Defining system strength service in terms of fault level also implies that increasing fault level is the only service that can be provided to improve system strength. While it is true that increasing fault level tends to improve system strength, that is not the only way to improve the stability of the network. Specifically, retuning control settings and upgrading firmware on existing plant can potentially increase the inverter based generation hosting capability of an area. This would be potentially the least cost way to improve system strength in some circumstances (but there is obviously a limit). However, there are significant impediments to doing so in the Rules, related to the "do no harm" framework, the recent changes to technical standards and high burden of other requirements recently added to the connection process. There is also no process defined in the Rules which would allow the coordinated retuning/upgrade of control systems throughout a part of the NEM and distinct disincetives for invidivual genetaors to participate in such a re-tuning (complex and costly 5.3.9 processes).

2. Have stakeholders identified any other significant issues as a result of the minimum system strength framework?	Our own experience is that the minimum system strength level in North Queensland was set too low. Our solar farm sought registration within approximately a month of the Rule taking effect, and it was later determined by the NSP that it had an adverse system strength impact. Clearly the way the minimum system strength level was determined was inadequate, and there was a shortfall in system strength from the outset. It was set at a level that resulted in all subsequent inverter-based generation in the area being required to provide costly mitigation strategies for system strength. It was close to two years later that AEMO declared a system strength shortfall. If the Rules were correctly applied, then there may be an inadequacy in the Rules' formulation that AEMC could rectify.
Section 2.4 – Key issues of the "do no harm" framework	
3. Do stakeholders agree with this assessment of the issues of "do no harm" framework?	The focus of the AEMC's approach to system strength appears to be predicated on sending locational signals to generators not to build in areas of low system strength. Perhaps a better approach would be to facilitate the transition to a low carbon, low cost generation fleet by most efficiently by providing a mechanism that efficiently values provision of voltage sources, in locations where it is most useful for supporting renewable generation. Under the current arrangements the NSP undertakes a PIA for a connection applicant, and most often the result is that the applicant must undertake an FIA. The PIA does not provide information that would allow an applicant to devise a mitigation strategy for the plant, nor even does it indicate with any certainty that one is required. In fact it is of little value in most cases. The FIA process takes months to complete, and the results are not made available to applicants in a way that would allow them to optimise a mitigation strategy. The Rules require the generator to specify a mitigation strategy without sufficient information to size any additional equipment. Once again, the testing of a proposed mitigation strategy takes months, and the only information provided about the outcome is if it is better or satisfactory, neither of which allows for optimisation of a solution. From an investor's perspective this is adding considerable risk and efficient investments may be significantly delayed or not proceed at all. We understand that AEMO is planning to develop a cloud-based solution that would enable a Generator's consultant to access a wide-area PSCAD model. We look forward to this development, which could improve this aspect of the process. In addition, the applicant has no visibility of what neighbouring applicants are proposing, nor of any connections which might become committed earlier than their application. If another nearby plant achieves a connection application then the whole process starts again, with a worse starting point for assessment of system strength. This effective 'queing' process, along with the poor visibility from modelling, is the largest source of risk new connections or non-synchronous generators attempting to upgrade their plant, under a 5.3.9 process. This is not a problem with the 'do no harm' requirement per se, but rather with the process that introduces significant risk and, for this industry, unacceptable delays. As new non-synchronous generation is installed and synchronous generation is retired it is inevitable that the system strength of the power system will decline. The decline of system strength is affected by the connection and

	retirement of other plant and entirely beyond the power of the generator to control. The generator, as the AEMC notes, is then at risk of gradually increasing constraint levels, which is a material risk for investors. The generator might control its local system strength by installing a synchronous condenser large enough to support its plant, or perhaps by installing a battery with grid-forming inverters of sufficient size to ensure the operation of the plant in an isolated system (the effective worst case system strength. The inverters would nevertheless need to be operable in a system containing other generation as well.). Sizing of such a solution optimally would be almost impossible for the generator under the current arrangements. Retrofitting such solutions to existing plant is likely to be an inefficient and expensive exercise with a very low probability of minimising cost to customers in the medium or long term. Extrapolating to its logical conclusion, if (nearly) all new plant is inverter-based, and constrained by system strength one might get to the ridiculous situation of having ample capacity but not being able to supply load. This is not so far-fetched. Consider what might have occurred if the constraint of the West Murray generation coincided with 10% POE demands last summer in Victoria and New South Wales. In other words, a system security issue is translated instead to reliability issue. Resorting to curtailment of VRE as a solution to system strength also does not consider the impact of system strength on the thousands of MW of solar rooftop pv installations in the NEM. We concur with the observation from TransGrid that a generator's individual mitigation strategy may not be optimally located, nor can it be relied on by the NSP to be in service when the generator is not operating. This is also the case for grid-forming inverters, and indeed, synchronous generators. It points to the need to pay for the services and therefore have some way to ensure they are available as required. Because of the issues with the PSCAD models, especially accessibility by generators and the size, complexity and computing power required to run them, AEMO or the TNSPs are currently best placed to run these models and identify system-wide solutions for system strength. These organisations are also the only ones who have full visibility of who is connecting at what locations and what the status of their project is. Either the information provision (including of PSCAD models and outputs) in the NEM needs to be significantly overhauled or the responsibility for solutions to system strength delegated to those who have the best opportunity to optimise them. AEMO and TNSPs also jointly have responsibiilty for transmission network planning in the NEM. It makes sense that these organisations should be responsible for planning systems strength as a part of that process.
4. Have stakeholders identified any other significant issues as a result of the "do no harm" framework?	As previously described the minimum stable fault level (or more correctly the maximum stable system impedance) for a part of the power system deteriorates each time another inverter-based generator connects in the area. The impact of additional inverter-based generation on stability of the power system can be exacerbated by: • Older plant being connected with early versions of firmware that is less stable • Requirements in the technical standards (especially S5.2.5.13) for very fast response from each plant, leading to combined response that is sub-optimal for stability, and can in some cases, contribute

	significantly to instability. The premise in S5.2.5.13 that faster response is always better response is demonstrably incorrect in the context of weak grid operation. The S5.2.5.13 access standard needs to be changed to allow that the settings should reflect the best outcome for the power system, not the fastest response from the generating system. Currently the wording of the standard, together with the requirement in 5.3.4A(b1) implies that faster response is better. Settling time has been used as a surrogate for stability, which is not a reasonable assumption for an over-damped system and fast rise-time for reactive power is not always an advantage when a range of system strength conditions must be considered and when coordinating control systems. The Rules need to be altered to allow coordinated re-tuning of existing plant in a streamlined efficient manner. There is no Rule that currently allows this. The recent changes made to settings and firmware in the West Murray region only highlight the urgent need to reform these Rules. No-one watching that process would want to participate in it, even though the changes have reportedly improved system strength. Grid-forming inverters are anticipated to have fewer problems with system strength than the commonly-used grid-following inverters. The clauses S5.2.5.13 and S5.2.5.5 should be reviewed to ensure that there is no impediment to the introduction of grid-forming inverters into the NEM arising from the current formulation of these standards. Specifically, grid forming inverters might rely on inverter-based voltage control, rather than voltage control through the PPC. This might affect the response time to a setpoint change. S5.2.5.5 has different requirements for synchronous and asynchronous plant, but grid-forming inverters will typically respond more like synchronous plant to voltage disturbances. There may be some aspects of S5.2.5.5 that need to be revised to avoid limiting the performance capability of grid-forming inverters. The minimum access standard for a 5.3.9 process is currently set to the existing performance standard (clause 5.3.4A(b)(1A), but for the sake of coordinated response for system strength, a lower standard might need to be accepted as it may significantly improve stability. There are also reasons other than system strength that might reasonably require a standard lower than existing to be accepted, including problems with compliance identified during commissioning or compliance testing where the impact on security or quality of supply is not material, but cost of rectification is disproportinately high. More generally the incorporation of system strength 'do no harm' in the 5.3.9 process is a major deterrent to the adoption of innovative solutions for improvement of plant performance or other changes that could benefit the generator and the operation of the NEM (as an example, the incorporation of batteries into an existing solar farm installation). When the proponent makes an application to alter the plant, the system strength conditions (owing to connection of other plant between the generator's commencement date and the date of the upgrade) will be different and potentially much worse than they were at the time of connection. This is another example of the adverse effect of the "run to the bottom" as the Commission expresses it. A change made at an earlier date would

	have had a greater chance of being accepted than the same change at present. Similarly, the level of expenditure to remedy any system strength impact increases over time. This is not a sustainable situation and is an impediment to upgrading of inverter-based equipment.
Section 2.7 – Conclusion	
5. What are stakeholders views on the Commission's proposal to consider evolving the framework to a more integrated approach for system strength in the NEM?	All the issues identified in response 3 above point to a coordinated solution for system strength that does not rely solely on individual generators providing mitigations solutions, and makes use of all possible options including the re-tuning of existing control systems. This would be more efficient and sustainable in the longer term. The solution should value contributions to system stability/strength from new plant, but look at how the overal cost to the NEM of providing adequate system strength to facilitate adequate supply in the future could be achieved. Like the minimum system strength framework, the do no harm framework is reactive, and leads to substantial delays and deterrents for new investment. Changes the current arrangements need to be pro-active in providing suitable conditions for connection of new plant, rather than impeding their connection. This is especially the case for renewable energy zones, chosen particularly for large investments and likley to benefit from efficient investments in co-ordinated network and stability measures. It is true that there can be synergies between provision of inertia and system strength. Likewise there can be synergies between system strength and fast-frequency response. Fast frequency response can substitute for inertia. However, both these combinations presuppose particular solutions (synchronous condenser in the first example, and grid-forming battery in the second). This suggests that in developing an integrated approach the Commission would need to take care not to require combinations of services which then preclude other innovative approaches which might be more cost-effective. The RIT-T process is notably slow, and unlikely to result in solutions to the timeliness issues raised in the Commission's discussion paper and our submission. Perhaps a process more like that for non-market ancillary services might work better, with tendering for services up to a level defined as necessary (with appropriate leadtime). However, system strength can be improved by means of network augmentations, so it would be reasonable to count this as a system benefit for the purpose of a RIT-T. Counting it as a benefit would mean that there would need to be a value assigned to the system strength improvement.

CHAPTER 3 – CONSIDERATIONS FOR PROVISION OF SYSTEM STRENGTH

Section 3.1 - What is system strength?

6. Do stakeholders agree with the Commission's characterisation of system strength?	We agree that the definition of system strength should be broader than fault level contribution, and that the current definition implies a particular solution for the service provision. The Commission could also consider the "stiffness" of the grid or voltage source or change in voltage for a change in reactive power as part of the characterisation. A stiff grid produces stable voltage. A strong voltage source resists the change in voltage resulting from a power system disturbance. [See also our accompanying letter for more explanation on this perspective about the definition of system strength]
7. Has the Commission set out all the necessary considerations for defining a system strength service? If not, what additional considerations could be included?	The Commission suggests that a system strength service would need to be (our interpretation added): • Appropriate – serves the purpose • Effective – does the job • Efficient – cost effective • Measurable – one should be able to put a value on the service The Commission has identified areas in which system strength benefits can be identified, ie • Maintaining secure operation • Alleviating constraints due to system strength (we might add preventing constraints to that) • Increasing hosting capacity for new non-synchronous generation and • Building power system resilience. Services that provide these benefits can be costed and provided on a competitive basis. Maintaining secure operation is a non-negotiable, and if system strength is compromised would need to be addressed through operational actions such as curtailment or disconnection. The costing of constraints (market benefits difference with and without) is straight-forward, and we believe likewise the value of increasing hosting capacity of the power system could be determined as market benefits. There are also broader societal costs from system strength deficits, not currently included in the NEO such as the impact of delayed transition to a low-carbon electricity system. Power system resiliance is not fully defined and could do with some more definition in order to be costable. It is related to HILP events, and could potentially be dealt with in terms of risk cost. The NEM has recently apparently developed more of an appetite to pay for resilience (although it hasn't really been discussed in these terms). For example, the technical standards for generators have recently been substantially raised, which is reflected into the cost of electricity. Later in Chapter 3 the Commission seems to narrow in on dispatchable services. These seem to be a subset of the potential solutions that provide improvements in systems strength, and which could be considered to provide a "service".

	We do not consider that a system strength service necessarily needs to be dispatchable. It is more important that it is available when required, which may mean that it can be provided all the time, such as building a network element.
8. Do stakeholders consider the regulatory definition of system strength should be updated/changed? If not, why not? If so, how could this be done?	The current definition of a system strength service is in terms of "fault level" and is clearly too narrow. It presupposes a particular solution for system strength deficit. The other definition of system strength (for *adverse system strength impact*) is in terms of stability: An adverse impact, assessed in accordance with the system strength impact assessment guidelines, on the ability under different operating conditions of: (a) the power system to maintain system stability in accordance with clause S5.1a.3; or (b) a generating system or market network service facility forming part of the power system to maintain stable operation including following any credible contingency event or protected event, so as to maintain the power system in a secure operating state. The Rules clause dealing with the *system strength requirements methodology* also refers to: • Fault level impact on secure operating state [could be protection operation, stability] • System stability after a contingency event [stability] • Risk of cascading faults [security/resilience] • Maximum load shedding or generation curtailment/shedding [reliability impact]
9. Do stakeholders consider that the system strength definition should recognise active and passive system strength procurement? If not, why not? If so, how could this be done?	It seems that the term active provision of system strength refers to ability to provide a strong voltage source to achieve more stable grid voltages. However, parts of the discussion paper seem to interpret this to mean ability to provide fault current. Fault current is only valuable in limited circumstances, for example, to allow protection to discriminate and correctly disconnect a fault using existing protection technologies. A strong voltage source provides most of the other benefits attributable to system strength. Passive refers to services to improve stability or improve fault level by reducing the impedance between a voltage source and another location. There are probably limits to the improvement that passive services can achieve. However, some of these passive services can provide good value for money expended (particularly control system retuning). They therefore should be valued in the mix of services and are potentially low hanging fruit. Network augmentations, while expensive, provide many other benefits (reliability, voltage stability, loss reduction) that are complementary with system strength improvement and also address some factors impeding investment in renewable generation (eg congestion land loss factors).

10. Do stakeholders agree that clarifying the NER system strength service definition is likely to contribute to more/broader options for the system strength provision?	Yes
11. Are there any additional sources of fault current in the NEM that can contribute to meeting system strength needs?	If by fault current the Commission is really intending to mean a strong voltage source, one might consider an HVDC voltage source converter in the mix. (Used for instance in Murraylink and internationally with offshore wind farms)
12. Are there any other technologies in the NEM that can contribute to meeting system strength needs that should be consideredi?	The following are some possible ways to improve the stability/ hosting capacity aspects of system strength: • Retuning controls or changing firmware and control strategies on non-synchronous generators • Application of stabilising controls on inverter based generating systems • retuning power oscillation dampers (PODs) on SVCs and HVDC systems • retuning SVC voltage controllers • Power system stabilisers on static excitation systems of synchronous machines may be able to contribute statcoms and • other voltage source converters can be fitted with PODs • stabilising controls on any load that uses an inverter front-end • stabilising controls on large processes (eg hydrogen plants) These actions can assist in the short term and should be investigated in a coordinated way. In the longer term, system strength will continue to decline if grid-following inverters continue to be used. The current understanding is that grid-following inverters are not capable of operating with SCR less than 1, so the options narrow as the SCR declines. Some other non-synchronous plant such as induction generators and doubly fed induction generators may be less susceptible to system strength issues than inverter-based equipment. Otherwise the choices may be synchronous machines and condensers, voltage source converter devices and grid-forming inverters.
Section 3.2 - Why is system strength needed?	
13. Do stakeholders agree with why system strength is needed?	Yes
14. Are there any additional reasons for why system strength is needed in a power system?	System strength does affect synchronous machines too, although they are less sensitive to it. Some other plant, like SVCs, are only designed for particular system strength levels, and may not be able to operate at lower levels. If the current development pattern were to continue, the power system might get to a stage where large parts of the system could not operate islanded, either because system strength is too low or because of a lack of reference

	voltage and frequency. This is the norm for the distribution system, but not so much for the transmission system currently. The consequences would be much higher loss of supply from many multiple contingencies. Power quality will also deteriorate as the system strength decreases. Harmonics will increase and there might be equipment that is sensitive to harmonics. Generators and loads that produce harmonic currents might find that they gradually become non-compliant over time, despite not changing their plant operation. This is a problem with the current definition of power quality compliance in parts of the relevant standards and also how these standards are being interpreted.
15. Do stakeholders agree with the characterisation of the impact of inverter-based generation on system strength?	The Commission should be careful with the definition of SCR. The described phenomenon (where addition of another inverter-based generator halves the SCR) is effective SCR. There are many different formulations of effective SCR. While they approximately describe the impact, in practice it is not quite as simple as described. This is the reason the PIA process has not been useful in screening potential adverse impact or in sizing mitigation strategies based on fault level improvement. (See next section for a more detailed explanation of why this is the case)
16. Are there any additional impacts on system strength that should be taken into account?	Currently there have been voltage oscillations in the NEM that AEMO and others have characterised as system strength. They certainly manifest when the system impedance is high and are associated with the voltage control interactions of inverter-based plant. However, the illustration in the discussion paper explained in terms of SCR, while appealing, is a too simplistic. Our understanding is that these interactions can occur at SCR levels that otherwise would not be expected to lead to instability. They are more akin to oscillatory stability and the inter-area oscillation modes between synchronous machines, although these oscillations arise from interactions between power-electronic devices. The analogy with inter-area modes of oscillations can be taken further: The inter-area modes were often associated with fast controls of static excitation systems. To resolve those inter-area modes, excitation systems were retuned and generators were fitted with power system stabilisers and power oscillation dampers were fitted to other devices like SVCs. The current "system strength" oscillation problems could also be addressed similarly. The frequency of the inverter oscillations are higher than those of synchronous generator inter-area modes. We expect this means that power-electronic devices could be used to damp the oscillations in a cost effective manner. This could be active damping within the voltage controls of inverters (grid-following and grid-forming) and power oscillation dampers tuned for the specific frequencies. The PSSs of synchronous generators with static excitation systems might also be able to contribute positively to damping. VSC statcoms and possibly even HVDC controllers might be able to contribute. Lowering impedance by building lines to connect weak areas to strong voltage sources will also help. Once all these things are done, we expect that the power system should be able to operate securely with generally lower system strength. However, there is still likely to be a limit, beyond which a (strong) voltage source will be required. Below this level other issues are likely to emerge such as less stable behaviour of synchronous machines as well as non-synchronous plant, and failure of protection schemes using existing technologies to operate correctly due to low fault level. SVCs, HVDC and other voltage control equipment will be affected if below their minimum short circuit level for operation. Power quality will deteriorate, especially harmonics and flicker. Voltages will become much harder to manage in the transmission system and more especially in the distribution system. Power system

	security and resilience would be adversely affected. The impact would not be uniform across the NEM and would likely occur in some areas remote from existing synchronous generation much earlier. This word picture suggests that we should try to manage the first level of "system strength" issues now, but aim to avoid the second level of system strength issues. This suggests that the AEMC strategy should encourage solutions that aid the first stage and avoid the second, without stifling the transition to a low carbon power system.
Section 3.3 - The provision of system strength in the NEM	
17. Do stakeholders agree that with the characterisation of system strength thresholds?	The Commission's characterisation of system strength shows three levels – green being for secure operation, blue being for incremental improvement (alleviating constraints, increasing hosting capacity and providing a resilience margin) and orange for an upper limit. The diagram seems to imply that system strength equates to fault level. The secure operation level includes a note that it doesn't include inverter-based generating systems which were required to implement system strength remediation schemes. We disagree with this note, as the schemes should not have been required other than for secure operation. The upper limit on system strength is characterised as an upper limit on fault level at a location, so whether this is a correct representation depends on the definition of system strength. Below the fault level limit there would presumably be an economically justifiable level of "system strength" based on optimum level of constraints.
18. Are there any additional thresholds or alternative characterisations that might be included in the investigation?	The discussion in section 16 suggests that there may be an additional threshold – there could be a level for which system security could be maintained with control system optimisation below a threshold for secure operation without that step (ie divide the green block into two thresholds). The maximum economic system strength level is likely lower than the fault level limit (potentially divide the orange into two levels).
Section 3.4 - The provision of system strength in the NEM	
19. Do stakeholders agree with the system strength attributes?	The Commission has characterised the attributes of system strength as lumpy. This reflects more on the source of system strength that the Commission considered for providing a service rather than the nature of system strength itself. For example if system strength service is provided by a grid forming inverter, it will be a much less lumpy service than that provided by a synchronous machine. System strength services provided by plant can often be binary. We agree that system strength is substantially location-specific. System strength services provided by plant can often be binary, because they often depend on whether the plant is in-service or not. This might also be true of a plant providing damping of oscillations, although if many plant contribute and one is out of service the effect would likely be an incremental change.

20. Are there any additional attributes of system strength that the Commission should be aware of?	System strength incremental benefits are unlikely to be linear with fault level change. In discussions with NSPs and looking at mitigation strategies we have been told that doubling the size of a synchronous condenser, for example, does not permit twice as many inverters to be connected to a node. This reflects that fault level is not a perfect surrogate for system strength.

CHAPTER 4 – EVOLVING SYSTEM STRENGTH FRAMEWORKS

Section 4.1 - Approach to developing a new framework	
21. Do stakeholders agree with approach (Plan, Procure, Price, Pay) to developing a new framework for system strength? Are there additional steps/concepts that should be explored?	The Commission should also consider the Process for deployment. There is a significant piece of work to define the process for coordinating controls to improve the oscillatory behaviour of inverters. Another aspect of the process relates to the current state of technology and the practicalities around what can achieved in the short term, compared with the longer term.
Section 4.2 - Models for delivering system strength	
22. Do stakeholders agree with the summary of the potential capabilities of each system strength model in Table 4.1?	Yes – it is a reasonable starting point.
Section 4.3 - Model 1: Centrally Coordinated	
23. Do stakeholders agree with the characterisation and assessment of a centrally coordinated model? Are there any other advantages and/or challenges?	The process is a challenge particularly achieving the required system strength in a timely fashion, when the existing situation is taken into account. The present system strength framework is causing years of delay to new connections and upgrades and costing the consumer millions in lost output from solar farms and wind farms, displaced in favour of coal and gas generation. If it takes five years or more to get projects from initial need to deployment this will not be workable. The NSCAS framework might be more workable than the RIT-T process, although it would be reasonable for market benefits attributable to system strength to be considered in any network augmentations. The coordination of controls should be undertaken as a first step. It might fall under small projects for RIT-T, in which case it would help for the systems standards to include a requirement for maintenance of sufficient system strength. A centrally coordinated model seems the logical way to manage system strength for renewable hubs. We note the Commission's reasons for preferring the separate framework to the NSCAS framework. The Commission could consider extending the minimum system strength framework of the current arrangements to fix the problems of timeliness and level of minimum service to cover future needs rather than current shortfalls. The framework could consider the ISP projected outcomes, state renewable generation objectives and level of renewable generation development interest, as well as retirements and changes in generation commitment patterns. We recommend the Commission look at the Texas model for renewable generation development and the way the level of interest in development of renewables was gauged for planning purposes.

	The Commission states: "The unpredictability of these dispatch patterns makes highly accurate forecasting and planning for necessary volumes of system strength challenging in the short term, and very nearly impossible over the medium to longer term. It may be difficult to account for these complexities in a long term, centrally coordinated planning approach." We maintain that the cost of too low system strength in the power system is extremely high, whereas the cost of overestimating the requirement in the short-term will buy some additional margin for resilience in the short-term at the incremental cost of bringing forward investment or service before it is needed. The NEM is moving from a predictable to less-predictable situation. It is manageable, but will require stronger grid, better grid support and output-focussed connection standards. For this arrangement it is reasonable that generators pay a contribution to system strength as a connection charge if they do not provide it. Generators should not be exposed to costs beyond the portion of cost that they would incur for their own connection needs. Customers should meet the additional costs, decreasing over time as the service is fully utilised by Generators. We agree that such a model would retain a signal for new entrants to invest in measures to reduce or offset their system strength impact. If the generator is upgraded in a way that improves their system strength contribution, then this should reduce the charge. The challenge will be defining the system strength contribution in a way that can meaningfully be costed or priced. Perhaps this could be measured in terms of impact on hosting capacity, although determining this would require significant EMT studies. The information provision and transparency around PSCAD models would need to be improved for this model (we acknowledge AEMO's efforts towards developing a cloud-based solution), because the Generator needs assurance that the NSP has correctly calculated the value of its system strength contribution, since this is offsetting NSP charges.
Section 4.4 - Model 2: Market based decentralised	
24. Do stakeholders agree with the characterisation and assessment of a market based decentralised model? Are there any other advantages and/or challenges?	We agree with the characterisation. The options favours solutions that are dispatchable solutions, and doesn't value passive solutions.
Section 4.5 - Model 3: Mandatroy service provision	
25. Do stakeholders agree with the characterisation and assessment of a mandatory service provision model? Are there any other advantages and/or challenges?	This model has many of the disadvantages of the current 'do no harm' scheme, particularly in the inefficient use of resources from uncoordinated development of services for fault level, and provides a significant disbenefit to generators required to provide the facility or service compared with incumbents. This model effectively treats fault level as system strength, and only values fault level that can be contracted or provided by the generating system. The amount of required service, whether based on capacity online or capacity

	installed is still quite arbitrary, and assumes a one size fits all approach that is unlikely to result in an optimal amount of service, nor in optimal locations. Contractable service is likely to be scarce in some areas and will become more scarce and expensive over time if synchronous generation retires. Generating technologies that provide their own voltage source (eg grid-forming inverters) and therefore do not require support from other sources should not be required to provide additional service. Wind and solar farms are often located in remote parts of the network. Increasing the fault level by a fixed multiplier at the generator's location might cause problems for the network, the generating system or other generators because of excessive fault level, or alternatively this might restrict the amount of generation able to be hosted in the network.
Section 4.6 - Model 4: Access standard	
26. Do stakeholders agree with the characterisation and assessment of an access standard model? Are there any other advantages and/or challenges?	If requirement to be able to operate at very low system strength environments were added to generator technical standards and non-synchronous generating systems were required to add this facility as a part of a 5.3.9 process, this would largely prevent the upgrading of any existing non-synchronous generating systems, because the cost of retrofit would be prohibitive. As previously explained, the types of system strength problems encountered up to now have not been directly related to short circuit ratio, but more to the interactions between control systems leading to oscillations for which damping is inadequate. This will not be resolved by applying a new technical requirement for operation at SCR of 3, as suggested in this model. It might be improved by inverters having power system stabilisers or control systems that actively damped or at least did not produce oscillations and were not affected by oscillations existing on the network. However, the problem has only recently been identified, is not well-understood by all manufacturers. The technology is still evolving rapidly at this stage and is only starting to be introduced in some inverters. If such a requirement were added to force generators to operate in continuous uninterrupted operation at lower SCR than currently required, and the control systems are not coordinated, it will become rapidly more difficult to connect any inverter-based system in the NEM, as is happening already under the current framework. A requirement that effectively forced all new grid-connected inverters to be grid-forming would likely choke investment in the near term, since the technology for grid-forming inverters in full-scale power systems is still in its infancy. This makes the investment expensive, risky and likely to encounter teething problems in the short term which will add uncertainty and delay.
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27. Are there other model(s) stakeholders think should be explored?	
28. What combiantions of models (i.e. hybrids) should be explored further?	A combination of centrally planned but long-term approach and market-based short-term approaches might be worth considering. Passive solutions are more suited to being centrally planned.
29. Do stakeholders have any suggestions as to how any/all the models set out could be implemented or modified? Please comment on any and all models possible.	

CHAPTER 5 – SYSTEM STRENGTH IN DISTRIBUTION NETWORKS

30. What factors make system strength provision in distribution networks unique from transmission networks?	
31. What are the key issues for system strength in distribution networks, including the magnitude and urgency of system strength issues in distribution networks?	
32. How should any system strength issues in distribution networks be addressed? Are any model(s) from Chapter 4 appropriate to address system strength provision in distribution networks?	