Australian Energy Market Commission

FINAL REPORT

INVESTIGATION INTO SYSTEM STRENGTH FRAMEWORKS IN THE NEM

15 OCTOBER 2020

REVIEW

INQUIRIES

Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 System strength is an essential system service for electricity markets. It is necessary to support a secure and stable power system. The provision of system strength is becoming more important given the rapid connection of large numbers of new, non-synchronous generation as we transition to a low emissions future.

2 This *Investigation into the system strength frameworks in the NEM* was initiated by the AEMC in March 2020, to consider how to evolve the system strength frameworks to become more agile and flexible, in order to facilitate the transition already underway.

3 This final report sets out the Commission's view on how the current framework should be evolved in a way that promotes the long term interests of consumers. This is consistent with the ESB's 2025 market design work considering the provision of essential system services, including system strength.

4 The final report presents our high level policy directions in relation to the development of evolved system strength frameworks. Working in collaboration with the ESB, AEMO, AER and all other stakeholders, the AEMC will build on these policy directions as we progress the towards making a draft determination for the rule change request from TransGrid, the *Efficient management of system strength on the power system (ERC0300)* rule change request (the TransGrid rule change).

Background on system strength services

5 Many variables are used to measure the outputs of a power system, but most relevant to system strength is voltage. The NEM's power system operates at various alternating current (AC) voltage levels, and includes a dedicated DC interconnection between Victoria and Tasmania, as well as both AC and DC connections between Victoria and South Australia and NSW and Queensland. The transmission network used for the bulk transfer of power operates at higher voltages than the distribution network.

6 The AC voltage at any point on the power system can be represented as a sine waveform. A smooth waveform, which doesn't distort easily, is important for the stable operation of the power system. Normal events on the power system can disturb and distort this wave form, such as a power system fault.

7 System strength is a quality of the power system that is related to the overall stability of the voltage waveform, including its ability to return to a stable state after disturbance events like faults. A stable voltage waveform is important for a number of reasons — mainly because it keeps the power system itself strong and stable, which as we transition to a lower-emissions generation fleet facilitates the connection and operation of large numbers of IBR generators.

8 Australia is at the forefront globally of connecting *non-synchronous*, IBR generators — such as large-scale batteries, wind and solar generation. This IBR generation, while critical to our future generation mix, also requires a certain amount of system strength to operate effectively. This growth in the penetration of IBR is occurring at the same time as the retirement and less frequent operation of many of the thermal *synchronous* coal and gas

generating units. These units used to provide system strength as a byproduct of their operation.

9 A lack of system strength can result in instabilities in the power system. This phenomena is exacerbated in the NEM by our "long and stringy" power system, meaning that many of the new IBR generators are connecting in peripheral, "weak" parts of the power system.

Background of the system strength framework

10 This issue was first considered by the AEMC, working closely with AEMO and industry, in 2017. We introduced two new frameworks to manage this emerging problem.

1. The 'do no harm' framework, where new connecting generators are required to deliver system strength commensurate to their 'harm' to the local fault current as a consequence of connection.
2. The minimum system strength framework, where AEMO identifies shortfalls of system strength, with TNSPs then working to address these expected shortfalls.

11 These new frameworks were among the first of their type globally, using the best knowledge and experience at the time.

12 Historically, these frameworks have been successful at keeping the power system secure. However, as the power system has changed over time, new challenges have emerged and the industry's understanding of system strength has evolved.

13 Stakeholders have provided us with valuable insights into this developing understanding, which has been critical to the development of our proposed evolved frameworks. They have also identified various issues that have arisen since the implementation of these frameworks, which we have worked to address.

14 The pace of the NEM power system transition means the time has now come to adjust and expand these frameworks. The changes required to the frameworks will need to reflect the change in the generation mix that is underway, and the move to large numbers of new non-synchronous IBR generation.

Market design to support the power system transition underway

15 The ESB has an essential system service (ESS) market design initiative (MDI) as part of its Post 2025 market design work program. This MDI is looking to develop a reform path for ESS that maps current and future required reforms to maintain the NEM in a secure, resilient state as it transitions to a low emissions future. The ESB published a Consultation paper in September 2020 on the Post 2025 market design, including an analysis of ESS.

16 The AEMC, as part of the ESB, is assisting the Post 2025 market design work. In addition, the AEMC has seven rule change requests on system services on foot, which complement and are interdependent with the issues being explored by the ESB in its on-going post-2025 market design projects. They offer opportunities to action the thinking and assessment done with the ESB work program. Aligning the work will mean the issues raised can be addressed cohesively and thorough consideration can be given to making sure any new system services arrangements are in the long-term interests of consumers. The AEMC is working closely with

the ESB, AER and AEMO on these matters.

17 Of particular relevance to this investigation, is TransGrid's rule change on *Efficient management of system strength on the power system.* This was initiated on 2 July 2020*.* The rule change request seeks to allow networks to be more proactive in the provision of system strength.

18 A draft determination for this rule change request is due by 24 December 2020. The timing of this project reflects stakeholder feedback that provision of system strength is an urgent issue and should be resolved as soon as possible.

Evolving the description of system strength

19 As this investigation has progressed, stakeholder feedback has demonstrated that there are different perspectives as to the exact definition and meaning of system strength. This is because there are a number of power system phenomena that are referred to as 'system strength', with new phenomena being observed and discovered over time.

20 An important place to begin the review was therefore to land on a clear description of system strength as an essential power system service.

21 The description of system strength set out in this final report incorporates the core physical phenomena and most material power system issues. This description details those issues that need to be addressed, to effectively and efficiently facilitate the power system transition.

22 System strength is fundamentally related to the stability of the power system voltage waveform. There are three key power system concepts that we have included as relevant to the overall stability of the voltage waveform. These three concepts include:

1. **Voltage waveform provision:** This is the *supply* of a 'strong' voltage waveform into the power system. It can be described as the 'source' of system strength and historically has been provided by synchronous machines (like coal, hydro and gas generators, or synchronous condensers). In future, it may be provided by new technologies like virtual synchronous machines. This is effectively the "backbone reference signal" on which the system voltage is based.
2. **Inverter driven stability:** Disturbances in the power system need to be "positively damped", which means they are settled quickly, and the system returned towards a stable, steady state. This stabilisation occurs through the actions of both network equipment and connected IBR generating plant. Of particular importance as the power system transitions is that we make sure the control systems of IBR generation are effectively tuned. This means their interactions with other inverters and the rest of the power system are stable, and effectively contribute to the damping of any instabilities. However, low levels of system strength can make it harder to manage these inverter control system interactions, which can result in an unstable system.
3. **Network stability management:** Network plant and generators include equipment that is designed to protect the individual plant from disturbances on the system, such as mechanisms for clearing faults on a transmission line. These protection systems, which

are critical to the safe operation of the power system, require adequately damped voltage waveforms to operate effectively.

23 These three concepts can be further grouped as they relate to the *supply* and *demand* for system strength. The first concept of *voltage waveform provision*, being the *supply* of system strength, then the second two concepts of *inverter driven stability* and *network stability management* being the *demand* for system strength.

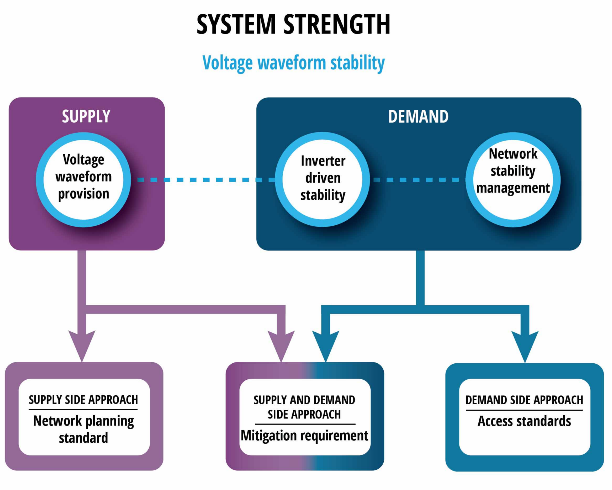
24 This approach to describing system strength has been used by the Commission to inform the development of the evolved frameworks set out in this report.

Evolving the system strength framework

25 The Commission has made a series of recommendations to evolve the existing system strength framework, which will help facilitate the power system transition.

26 The concepts of the *supply* and *demand* for system strength described above have been drawn on to design a mechanism for delivery of the efficient volumes of system strength needed to support effective connection of IBR generation. The evolved frameworks continue to share the costs of system strength between generators and customers, but does this in a more pragmatic manner. These recommended components are shown in Figure 1 and described below.

Figure 1: Overview of the evolved system strength framework



Source: AEMC

- **Supply side:** The recommendations underpin a coordinated model for the delivery of system strength. TNSPs, working with AEMO, would face an obligation to proactively provide the volumes of system strength needed to maintain security, and to facilitate the effective connection and operation of expected volumes of new IBR generation. By drawing on the existing integrated planning frameworks and the established system engineering practice of meeting a defined system standard, this coordinated supply side model is designed to deliver efficient volumes of system strength, while managing costs by utilising the existing NEM economic regulatory frameworks.

- **Demand side:** The recommendation is to incorporate two new technical standards that would apply to all new generators connecting to the power system, such that they use efficient amounts of system strength. This would help to make the best use of this limited, common pool resource, which in turn helps keep costs low for consumers.
- **Effective coordination between the supply and demand sides:** In order to make sure that the demand and supply side arrangements are working effectively with each other, our recommended system strength mitigation requirement - shares the costs of providing system strength between customers and generators.

  Under the evolved framework, consumers would pay for system strength, reflecting that they derive a benefit from its provision. Generators would also pay a contribution to these costs as they are causing some of the increased need for these services. These fees would then be used to reduce the total amount that customers pay through their TUOS charges. This would result in the effective utilisation of the system strength that is supplied, as well as making sure it is balanced with levels that are demanded.

27 In designing this evolved framework, we used the Commission's system services design framework, as set out in the Discussion paper and *System services consultation paper*. In doing so, we considered the "4Ps", or the concepts of *planning*, *procuring*, *pricing* and *paying* for system strength.

28 These recommendations are designed to build on and evolve the existing framework, and include the following changes:

- By supporting the proactive provision of system strength at levels needed to support efficient connection of new generation in specific parts of the system, the evolved framework is intended to help speed up the connection process, and help to remove some uncertainty faced by new connecting generators.
- The framework would also more effectively identify and address low levels of system strength as they arise in NEM regions, to help maintain system security at the lowest possible cost.
- It would also allow for the provision of increased levels of system strength to enable greater output from lower cost generation sources.

29 These recommended changes also look to value the system strength required by the power system.

Table 1: Comparison of existing and recommended evolved framework

	EXISTING ARRANGEMENTS	EVOLVED FRAMEWORK RECOMMENDATIONS

Supply side	Minimum system strength framework:
	• AEMO identifies shortfalls of system strength through detailed and complex Electromagentic transient (EMT) modelling of the system.
	• TNSPs then are required to procure system strength services needed to address the shortfall.
	• The use of shortfalls has resulted in a reactive framework (i.e. a shortfall is only identified where there is an issue with system strength), which has resulted in:
	  • TNSPs often only having limited solutions to meet the shortfall
	  • delays in the connection of new generators while modelling is occurring, and shortfalls are being addressed
		A new system strength network planning standard, which would be defined in the NER:
		• The standard would be designed to proactively deliver needed an efficient level of system strength. This is a level of system strength where the benefits of having more system strength in the system (e.g. to support efficient connection of new generation and maintain security, to deliver energy to customers and help reduce wholesale prices) outweigh the costs of providing that system strength. In other words, shortfalls would no longer be declared – instead there will be a higher level of system strength that needs to be proactively provided by TNSPs. This would likely vary at locations across the network. This would overcome the problems that exist in the current reactive framework.
		• AEMO would play a key role in providing guidance and detail around the standard.
		• TNSPs would be required to provide system strength to meet the standard – TNSPs would be able to consider different options for providing system strength e.g. retuning generators, contracting with synchronous generators or installing synchronous condensers. This would set the framework up to be flexible and adaptable as technology changes over time. This is a key aspect of the policy that would require further development over the coming months.
		• The concept of a shortfall would no longer exist – instead, the entire level of system strength would be valued, with this addressing the missing market for system strength.
		• The provision of system strength would be targeted at the investment timeframes – the ESB's 2025 work is still considering how to provide synchronous services in operational timeframes.

Demand side	Do no harm arrangements: •	Introduction of a new set of generator access standards, to make the most efficient use of the available system strength – requiring those generators that 'demand' system strength to

	EXISTING ARRANGEMENTS	EVOLVED FRAMEWORK RECOMMENDATIONS
	• AEMO develops system strength impact assessment guidelines that allows TNSPs and generators to assess the impact of a new generation connection on system strength. • From this, the new connecting generator is obligated to 'do no harm' to the security of the power system, in relation to system strength. • As such, if the new connecting generator has a negative impact on the fault level (a measure of the level of system strength in that area), then that generator must remediate that impact.	undertake actions to minimise how much system strength they demand.
Coordination of supply and demand side		Introduction of a new charging regime based on the marginal cost associated with the proactive provision of system strength for those generators who elect to connect in parts of the power system where networks have proactively provided system strength. • This means, at the preliminary impact assessment stage (PIA), a generator-specific charge would be calculated from publicly available information regarding the generator's system strength impact and location. • The generator can then choose to pay this charge (which would be a contribution to lowering total TUOS charges paid by consumers) or to undertake a full impact assessment (FIA) and potential remediation at its own expense. The remediation would be expected to be considerably more expensive than the charge. • Outside of these areas, generators would be able to connect and would face the costs of remediating their own system strength needs, as determined through the PIA/FIA process as currently occurs through the do no harm process. • This would send clear locational signals to generators, including those that supply system strength, about where to locate to maximise the effectiveness of system strength in the network.

1 Below we step through the three components of the evolved framework, being the supply side and demand side recommendations, and how these two are coordinated.

Supply side - coordinated provision of system strength

2 The Commission considers that a coordinated approach is the most effective way to supply system strength in the NEM. The evolved system strength frameworks utilise the existing planning arrangements to enable AEMO and TNSPs to work together, to provide system strength at the levels needed to facilitate the transition.

3 The evolved framework establishes a network planning standard for system strength. This is then integrated into the existing joint network planning and regulatory arrangements, to drive proactive provision of the volumes of system strength needed to support the changed generation mix.

4 Under AEMO's guidance, TNSPs would be responsible for proactively procuring the efficient level of system strength needed to:

- keep the system secure, and
- support the efficient connection and dispatch of generation, in those areas where it is expected to be needed in the near future.

5 TNSPs would face an obligation to meet a system strength standard. In practice, this would involve:

6 **Plan:** The planning components of the evolved framework consist of two stages.

- Stage one: AEMO would undertake an assessment, utilising inputs from the ISP and other planning (as relevant), of the nodes within the network where the standard would apply, as part of the annual system strength report. This stage of the process includes consideration of the volumes of generation expected to connect at each particular node, as defined through the integrated planning process.
- Stage two: Utilising the existing joint network planning processes, the TNSP plans how to procure system strength services to meet their requirements under the NER, in accordance with AEMO's work in stage one.

7 **Procure:** There are numerous possible procurement options that a TNSP may consider in order to meet the system strength planning standard, just as they do now with meeting their jurisdictional reliability standards. This includes:

- network options such as building new network assets such as synchronous condensers
- non-network options such as contracting with generators that supply system strength, or utilising new technologies such as grid forming inverters and techniques such as the collective retuning of the control responses of existing generators.

  TNSPs would make these decisions based on the current economic regulatory framework, where decisions are made to maximise net benefits for customers.

8 **Price:** under the economic regulatory frameworks, the AER sets an allowance for each network business that aims to ensure that consumers only pay for efficient expenditure and to incentivise TNSPs to undertake efficient decisions. This framework would act to incentivise network businesses to make decisions that are efficient, and maximise the net benefits for customers. Therefore, the 'price' for system strength would depend on these considerations. The Commission is concerned that in some markets, depending on how urgently system strength is needed, there may be a lack of options available for providing system strength, which could lead to parties seeking to charge higher costs to the TNSP than may otherwise be the case. The Commission will continue to consider how to address these issues through the TransGrid rule change process.

9 **Pay:** The AER determines the maximum amount of revenue TNSPs can recover from consumers over a defined regulatory control period for ‘prescribed transmission services’. Prescribed transmission services, including the recommended system strength standard, are those that are regulated by the AER – and currently, all of these are paid for by consumers through transmission use of system (TUOS) charges. Therefore, these charges would be paid for by customers in the first instance. However, consistent with the current arrangements, generators should also bear some of the costs, given they are causing system strength requirements to change. This occurs through generators paying a charge, as per the system strength mitigation requirement, which is used to offset TUOS. This is discussed further below.

10 Under the evolved framework, TNSPs will have the obligation to provide system strength services, and may use network or non-network solutions to provide these services. Given that the assets that provide these services will have operational implications, we consider that AEMO coordinate and control (in some form) these solutions in the operational timeframe through the dispatch process. This aligns with current arrangements, and is necessary to ensure that the power system is maintained in a secure operating state. We will develop the specifics of these mechanisms to provide AEMO with operational control both through the draft determination of the TransGrid rule change request and the ESB Post 2025 market reform project.

Demand side - new access standards to manage the need for system strength

11 Experience from connecting generators in the NEM recently has shown the potential need for new access standards, to support the security of the power system and reduce the demand for system strength services.

12 The Commission is recommending two changes to the generator access standards to introduce new access standards for system strength. These new access standards would require connecting generators to be capable of the following:

1. **Short circuit ratio:** new connecting generators must have a capability to operate stably as available system strength reduces, as measured by a short circuit ratio (SCR) capability. This would allow for stable operation even in lower system strength conditions, and would reduce the amount of system strength that TNSPs would need to procure.
2. **Voltage phase shift:** new connecting generators would face minimum (achievable by type 3 wind turbines) and automatic (higher and achievable by other IBR) access

standards for maintaining continuous uninterrupted operation following a large shift in the phase of the voltage at the generating system. This new standard would not apply to synchronous generating systems, since those machines do not cause this impact, and would rely on the generator and network service providers to negotiate an appropriate level for the connecting generating system.

13 At this stage, we have not determined the specific values associated with the SCR or phase shift access standards. The Commission will consider this further through the draft determination of the TransGrid rule change process, and will be informed by AEMO and industry engagement to understand the technical and economic implications of specific settings.

14 In addition, the Commission will continue to review the arrangements for damping, which is the way that disturbances on the system are managed and returned to a steady state.

System strength mitigation requirements

15 The Commission also considers that a system strength mitigation requirement (SSMR) should replace the existing 'do no harm' arrangements. This will result in effective utilisation of the system strength being supplied, as well as making sure it is balanced with levels that are demanded.

16 Part of the SSMR is the establishment of **system strength zones.** These are the areas inside which system strength, which is proactively provided by TNSPs, can be effectively used by generators to facilitate their connection and stable operation. These zones will be based on the physics of the service and electrical distance.

17 At a high-level, this requirement will address the issues that are present in the current 'do no harm' arrangements, while reflecting the increased provision of system strength from the supply side reforms. It involves:

- The provision of clear price signals regarding system strength for new generators connecting both inside and outside of system strength zones.
- Remediation requirements for generators outside of system strength zones. That is, remediation requirements will apply to generators connecting in areas of the network where the system strength proactively supplied by the TNSP does not reach.
- Levying a charge on each generator who connects within a system strength zone, with that charge being equal to the efficient marginal costs of the TNSP providing additional system strength, due to that generator's connection.

18 A key objective of this SSMR framework is to create clear price signals for generation, based on their relative demand for system strength services. The SSMR framework would create incentives for generators to connect to those parts of the network where they would make the most efficient use of available system strength, while also bearing some portion of the costs of providing system strength.

19 These signals work in tandem with the new access standards that encourage generators to be capable of operating at lower levels of system strength, and should be as simple and predictable as possible to support investment decisions.

20 Additionally, such incentives would also enable new connecting generators to consider the costs of remediating adverse system strength impacts when making investment decisions. This would enable generators to consider the most cost effective solutions and contribute to reducing the overall costs of new generator connections to the system.

Consideration of distribution networks in the evolved framework

21 The Commission has concluded that the current arrangements regarding system strength, as applicable to distribution networks, do not require any changes in an evolved framework at this point in time.

22 This is since the changes to the supply side reforms at a transmission level will flow through and have positive impacts on the use of system strength at the distribution networks due to the more proactive procurement. Additionally, we consider that the existing joint planning arrangements are sufficient for that purposes of the evolved framework, and encourage distributors, TNSPs and AEMO to continue to work together to better refine the practical operation of these frameworks to make sure they are fit for purpose in the transitioning power system.

23 Finally, as the system strength zones described above may propagate into distribution networks, it follows that generators connecting in distribution network may still be captured by the SSMR framework described above. This means that generators connecting in distribution networks will not be able to "free ride" the system strength provided by TNSPs in the transmission

Considerations for transitioning to the evolved framework

24 The Commission acknowledges the urgency to implement the evolved system strength frameworks, given the current frameworks are causing time and cost delays, which flow through to consumers. As such, the time taken to transition to the evolved framework should be minimised as much as possible, noting that there are different costs and risks associated with each potential implementation timeframe.

25 In considering these timeframes, we have assessed whether specific transitional mechanisms might be warranted, and what they might look like.

26 The Commission's analysis of the different potential timeframes for implementation of the evolved framework suggests:

- It would only be appropriate to rely on "status quo" arrangements - that is, introduce no specific transitional mechanism - if we can be confident of a relatively quick implementation timeframe and/or no immediate system security issue(s) would be posed by doing so.
- Interim arrangements, including an interim standard or other specific measures, may be appropriate if a relatively quick implementation is not possible due to the difficulties in quickly implementing the framework, and/or there are concerns of market intervention, delays associated with the development of relevant supporting frameworks, and market power issues. In these cases, we consider these kinds of interim measures would allow

for rapid delivery of the key aspects of the evolved framework, while minimising the extent of uncertainty and difficulties associated with implementing transitional mechanisms.

- For the purposes of providing a transitional arrangement only, we consider that an alternate structured procurement mechanism(s), such as directed procurement by AEMO, would unlikely be suitable, unless transitional timeframes were expected to be significant, such as greater than five years.

  The Commission considers that some form of interim arrangements appears likely to be warranted for a transition mechanism. However, we remain committed to implementing the evolved framework as rapidly as possible given the urgency of the system strength issues. At this stage, we consider an interim standard is likely to offer the most measured balance of risk with the best integration with the evolved framework. The transitional arrangements will continue to considered through the progression of the TransGrid rule change request.

Next steps

27 The Commission intends to engage with stakeholders through a series of technical workshops and meetings with other interested stakeholders. We are also engaging with industry, including equipment manufacturers, generators, TNSPs and AEMO, to make sure that our recommendations are technically feasible. Finally, we also continue to work closely with the ESB, AEMO and the AER to progress our thinking in alignment with the Post 2025 market design program, and in particular, the ESS MDI.

28 The Commission also intends to hold a public forum on 22 October 2020 in order to seek stakeholder feedback on the direction set out in this report. Registrations for this can be made on our website.

29 Based on the high level design of the evolved framework set out in this final report, the Commission will continue to develop the next level of detail of these reforms, as well as any transitional mechanisms, through the TransGrid rule change. Stakeholders will then be invited to provide formal submissions to the draft determination of this rule change.

CONTENTS

1 INTRODUCTION

System strength is an essential system service required for a secure and stable power system. This review was initiated by the AEMC in March 2020 to consider improvements to the system strength frameworks to more effectively and efficiently address system strength issues in the national electricity market (NEM), now and in the future.

The current frameworks were put in place in 2017 to address immediate system strength issues. Historically, these frameworks have been successful at keeping the power system secure. However, as the power system has changed over time, new challenges have emerged and the industry's understanding of system strength has evolved.

The pace of the NEM power system transition means the time has now come to adjust and expand these frameworks. The changes required to the frameworks will need to reflect the change in the generation mix that is underway, and the move to large numbers of new non-synchronous inverter-based resources (IBR), more specifically IBR generation.

The review was initiated with the publication of a Discussion paper, which covered:

- key issues with the current system strength arrangements
- attributes and considerations for the provision of system strength
- ways to evolve the system strength framework.

This final report sets out the AEMC's view on how the current arrangements should be evolved to be more effective and efficient, with this being consistent with the ESB's work in the Post 2025 project.

1.1 The power system is in transition

This review was carried out in the context of Australia's transitioning power system. The NEM power system is moving from being dominated by a small number of large synchronous generators (such as coal and gas),[1] to a system based increasingly on a larger number of distributed IBR generation technologies, such as wind, batteries, and solar.[2]

The scale of this power system transition is expected to see the NEM's current capacity being replaced entirely by 2040. This involves 15GW of synchronous capacity exiting the market by 2040 with 26-50GW of IBR generation entering; for context, it is worth noting that the NEM's current total installed capacity is approximately 50GW.[3]

A reduction in the levels of synchronous generation is a key outcome of this transition. This is partly due to the retirement of synchronous generators as they reach the end of their operational lives. It is also due to these plants being dispatched less in the wholesale market,

1 Synchronous machines (including synchronous generators, motors and condensers) are electromagnetically coupled to the AC power system. This means that some interactions of the machine with the overall power system are dictated, and determined, by the physical characteristics of the machine. This includes kinetic inertial responses to a frequency disturbance, or a reactive current response immediately after occurrence of a fault. Synchronous machines also inherently contribute to maintaining the stability of the voltage wave form.

2 IBR generation is electronically coupled to the AC power system through control systems, where many of the responses are determined by the specific settings of the control system.

3 AEMO, *2020 Integrated system plan,* 2020, pp. 12

due to lower cost wind and solar generators displacing them. Some synchronous generators have already exited the market with those remaining expected to retire in the next 20 years.

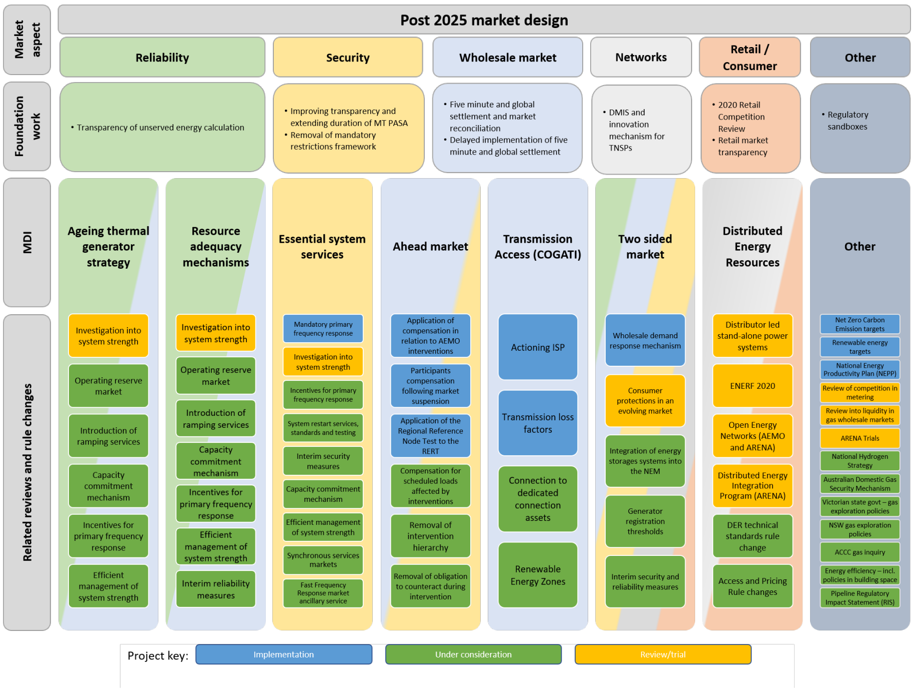
Many of the services required for power system security have traditionally been provided as a byproduct of synchronous generators and have not been separately valued. However, given the changes in the generation mix described above, and the reduction in the levels of synchronous generation, these services are now becoming less available.

One such security service is system strength. The continued management and provision of this service is critical to maintain a safe and secure power system, as well as enable a smooth transition towards a low emissions future by supporting the changing generation mix.

1.2 Redesigning the market to support the transition

There are a significant number of market design reforms on foot. Most significant is the Energy Security Board's (ESB) work on developing a post 2025 market design to support this power transition as shown in Figure 1.1, in which the AEMC is assisting as part of the ESB.

Figure 1.1: Key aspects of ESB's market design work program



Source: AEMC

This review complements and is interdependent with the work of the ESB in its 2025 project.

In particular, a key workstream of the ESB's 2025 work is looking at how essential system services (ESS) are provided. Coordinating ESS incentives and mechanisms will be essential in maintaining NEM system security at least cost for consumers, now and into the future.

The ESS workstream maps current and future required reforms to maintain the NEM in a secure, resilient state as it transitions to a low emissions future. The ESB's September consultation paper mapped current and future requirements for procuring ESS. The options by which to do so and a roadmap for the provision of essential system services will be developed for further consultation in December 2020.

This review offers an opportunity to action the thinking and assessment done within the ESB work program. Aligning the work will mean the issues raised can be addressed cohesively and thorough consideration can be given to making sure any new system services arrangements are in the long-term interests of consumers. Therefore, the AEMC has worked closely with the ESB, AEMO and AER in terms of developing the recommendations in this report, and will continue to do so over the coming months. Moreovere, the recommendations are consistent with the ESB's 2025 project.

The AEMC has also received a rule change request from TransGrid that relates to the operation of the system strength framework: *Efficient management of system strength on the power system* rule change request. The AEMC initiated on 2 July 2020, as part of the *System services consultation paper.* A draft determination for this rule change is due on 24 December 2020, and this rule change will allow us to implement the findings from this review. The timing of the draft determination reflects stakeholder feedback that provision of system strength is an urgent issue and should be resolved as soon as possible.

1.3 Purpose of this review is to evolve the frameworks

This review considered whether improvements can be made to the system strength frameworks to address the decreasing supply, and increasing demand, for system strength in the NEM, now and in the future. This is critical for an effective and efficient transition to a lower emissions future, due to the essential nature of system strength to making sure the power system continues to operate in a secure manner.

Australia is at the forefront globally of connecting new non-synchronous generators, often in areas with low levels of system strength.[4] Frameworks to manage the issues associated with connecting IBR generators in low system strength environments were introduced in 2017, and were among the first of their type globally. Historically, the current arrangements have been successful at keeping the power system secure. However, as the power system has changed over time, new challenges have emerged and the industry's understanding of system strength has evolved.

Stakeholders have provided us with valuable insights into this developing understanding, which has been critical to the development of our proposed evolved frameworks. They have also identified various issues that have arisen since the implementation of these frameworks, which we have worked to address. The pace of the NEM power system transition means the time has now come to adjust and expand these frameworks. The changes required to the frameworks will need to reflect the change in the generation mix that is underway, and the move to large numbers of new non-synchronous IBR generation.

4 AEMO, *Maintaining power system security with high penetrations of wind and solar generation*, October 2019, p. 32.

1.3.1 Scope of the review

The majority of stakeholders agreed that the frameworks need to evolve and adapt, as the power system transitions. The review was to explore evolution of the current framework to better facilitate the timely and efficient provision of system strength services, in order to:

- maintain safe and secure power system operation
- help unlock low cost energy supply for consumers
- enable significant volumes of new IBR generation connecting that is occurring as part of the transition of the power system.

To achieve this, additional measures, as well as changes to both the minimum system strength and "do no harm" arrangements, were considered to evolve the way system strength is provided in the NEM to be more future proof.

1.3.2 NEO assessment and principles used in this review

The National Electricity Objective (NEO) is the overarching objective guiding the Commission's approach to this work program.[5] As discussed in the AEMC's guide to 'applying the energy market objectives',[6] the NEO is an economic concept and is intended to be interpreted as promoting efficiency in the long-term interests of consumers that depends on the consideration of a specific set of variables.

Principles for NEO assessment

Any proposed change to the current framework was assessed in terms of whether it is likely to support and improve the security and reliability of the power system along with the effectiveness and efficiency of the frameworks. In particular, any change was considered as to how they meet the following principles:

- **Promoting power system security[7] and reliability:**[8] Having regard to the potential benefits associated with improvements to system security and reliability brought about by the proposed rule changes, weighed against the likely costs.
- **Appropriate risk allocation**: The allocation of risks and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Where practical, operational and investment risks should be borne by market participants, such as businesses, who are better able to manage them.
- **Technology neutral**: Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

5 In performing or exercising any function, the AEMC must have regard to the national electricity objective - Section 32 of the NEL. The NEO is: to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system.

6 In 2019 the AEMC updated its Applying the energy market objectives - a guide for stakeholders document. More on this update and the background of energy market objectives can be found here: https://www.aemc.gov.au/regulation/regulation

7 System security underpins the operation of the energy market and the supply of electricity to consumers.

8 Reliability refers to having sufficient capacity to meet consumer needs.

- **Flexibility:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment.
- **Transparent, predictable and simple:** The market and regulatory arrangements for frequency control should promote transparency and be predictable, so that market participants can make informed and efficient investment and operational decisions.

These principles are the same used in the *System services consultation paper*, inclusive of TransGrid's rule change request.

Plan, procure, price and pay ('4Ps') framework

As set out in the Discussion paper, the evolved framework was developed through the '4Ps' service design framework that sets out considerations for planning, procuring, pricing and paying for a system service.[9]

In that paper, the Commission described the different considerations required when developing new or amending existing market and regulatory frameworks. This framework is discussed where relevant throughout this report. Within each 'P' categories, there exist a range of options, which are explored in the figure below:

Figure 1.2: Considerations for Planning, Procuring, Pricing and Paying for a system service

Source: AEMC

9 AEMC, *Investigation into system strength frameworks in the NEM, Discussion paper,* March 2020, p. 56.

1.4 Next steps in evolving the frameworks

The Commission will use the TransGrid *Efficient management of system strength on the power system* rule change request, to develop detailed implementation details of the recommendations made in this report for the evolved framework.

In order to make sure the draft determination is as robust as possible, the Commission will also continue to engage further with stakeholders. In particular:

- a public workshop on the key recommendations made in this report will be held on 22 October 2020.
- there will be further meetings of the technical working group
- we welcome bilateral meetings if stakeholders are interested.

The Commission will then consult on the draft rule to implement the recommendations in the draft determination for the TransGrid rule change, due on 24 December 2020.

The Commission also considers there are a number of other areas where there are opportunities for further development, including:

- processes for collective retuning of existing generators, to enhance the overall hosting capacity of the network
- consideration of whether the existing generator access standards require updating, to better account for IBR generators

The Commission will look to work closely with stakeholders in future to explore these options.

1.5 Structure of this paper

This final report discusses the Commission's view on how to evolve the way system strength is provided and managed in the NEM to be more future proof. This report's remaining chapters covers the following:

- Chapter 2: Evolving the description of system strength
- Chapter 3: Overview of evolved system strength framework
- Chapter 4: Supply side - Coordinated approach to provision of system strength
- Chapter 5: Demand side - Generator obligations
- Chapter 6: Efficient coordination of supply and demand - System strength mitigation requirement
- Chapter 7: Consideration of distribution networks in an evolved framework
- Chapter 8: Considerations for transitioning to the evolved framework
- Appendix A: Further information on the description of system strength
- Appendix B: Further information on setting a system strength standard

2 EVOLVING THE DESCRIPTION OF SYSTEM STRENGTH

BOX 1: SUMMARY OF KEY FINDINGS

The Commission has found over the course of this review and from stakeholder feedback that different perspectives exists as to what power system outcomes are encompassed by the provision of 'system strength' in the absence of a more explicit definition or description in the NER. The Commission therefore concludes that the existing regulatory definition of system strength service needs to be evolved to better reflect the true nature of what ‘system strength’ is, as currently being experienced in the power system.

As such, we developed a description of system strength that aims to clearly define and bound the relevant physical power system issues currently arising in the power system. There are three key power system concepts that determine the stability of voltage waveforms in the power system:

1. **Voltage waveform provision —** The supply of a 'strong' voltage waveform into the power system is the 'source' of system strength. This is the backbone reference signal on which the system operates.
2. **Inverter driven stability —** Disturbances in the system need to be positively damped towards a stable steady state, through the actions of both network equipment and connected generating plant. This includes the stability of inverters and their interactions with other inverters and the rest of the power system.
3. **Network stability management –** Network plant and equipment require adequately damped voltage waveforms to operate effectively. This includes the need to provide fault current to operate protection mechanisms for fault management.

These can be further grouped into the first concept being the *supply* for system strength, then the second two concepts being the *demand* for service. This approach is being used by the Commission in evolving the system strength frameworks.

The Commission also looked at a simple, measurable metric to reflect this evolved system strength concept, unfortunately no such metric exists. However, a combination of metrics may be able to appropriately approximate the evolved system strength concepts and is explored further in Chapter 4.

The first step in evolving the regulatory frameworks for system strength is to consider and define exactly what is meant by the term "system strength".

This chapter provides a description of system strength using key technical power system concepts. These technical concepts then form a basis for evolving the existing frameworks, starting with amending the existing regulatory definition of the service.

This chapter sets out the following:

- the current definition in the NER of system strength services
- a summary of stakeholder engagement and views, undertaken to evolve the understanding of system strength services in the NEM
- an outline of the role of system strength in the power system
- a high-level description of the evolved understanding of system strength, including the key power system concepts that determine system strength
- considerations for measuring and assessing the need for system strength.

A further exploration of system strength, the underlying power system concepts and the different ways system strength can be influenced can be found in Appendix A. Additionally, an introduction to system strength is also provided in that appendix for those who have not engaged with this topic before.

2.1 The description of system strength needed to be refined

The *National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10* (Fault levels Rule), which implemented the existing system strength frameworks. The Rule defined a 'system strength service broadly as 'a service for the provision of a contribution to the three-phase fault level at a fault level node'.[10]

While the Fault levels Rule defined a 'system strength service', it did not introduce an explicit definition of system strength in the NER. It was recognised that the term 'system strength' is not a power system engineering term but rather one used to describe a group of power system requirements.

Since that time, AEMO has been using the following definition of system strength:[11]

> *"the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance."*

The AEMC's consultation during this review has found that different perspectives exists as to what power system outcomes are encompassed by the provision of 'system strength' in the absence of a more explicit definition or description in the NER.

Industry participants have different views on whether or not system strength should encompass multiple aspects of secure power system operation. For example, stakeholders hold differing views on the extent to which voltage stability standards should be considered as part of the definition of system strength.

The Commission therefore concludes that the existing regulatory definition of system strength service needs to be evolved to better reflect the true nature of what 'system strength' is, as currently being experienced in the power system.

10 Chapter 10 of the NER.

11 AEMO, Renewable integration study — stage 1 report, April 2020, p.50.

2.2 Stakeholder engagement to refine the description

The Commission has developed a description of system strength through extensive consultation with various stakeholders and through our engagement with our consultant, GHD, who were engaged to provide technical advice on this project.

AEMO's work to date on system strength has also been a critical input into this review and as such, the AEMC's and AEMO's understanding of system strength is aligned.

The key stakeholder engagements to develop the definition of system strength include consultation:

- on the March 2020 Discussion paper and stakeholder submissions received in response
- through the technical working group established for this project, which comprised a broad cross—section of stakeholders.

The main points raised in these consultations were:

- Almost all stakeholders agreed that the Commission should examine and expand the NER definition of system strength services.[12]
- Various stakeholders noted that the current AEMC and AEMO definitions of system strength are too generic and supported a more granular definition to remove ambiguity.[13]
- Many stakeholders suggested system strength should be defined in terms of impedance and plant control systems.[14]
- ENA, Energy Australia and CEIG, while agreeing with pursuing a more granular definition, also noted that system strength may not be able to be defined precisely, should remain simple and avoid being overly prescriptive.[15]
- Mondo, Reach Energy, Energy Queensland, AGL noted that the definition should capture the value of all technological solutions. This is while noting that the definition itself should remain technology agnostic.[16] This includes stakeholder support for the ‘active’ and ‘passive’ aspects of the AEMC system strength description.
- Broadly, the system strength technical working group members agreed that the problem of system strength pertains to both power electronic behaviours and interactions as well as the provision of a resilient voltage waveform when the AEMC presented our working description of system strength on 9 June 2020.[17]

More detail on how system strength relates to power system stability can be found in Appendix A.

12 Submissions to the March 2020 Discussion paper: WSP, TasNetworks, Siemens, Reach, Mondo, Hydro Tasmania, Energy Queensland, Energy Networks Australia, Energy Australia, Clean Energy Investor Group (CEIG), Clean Energy Council, Citipower Powercor & United Energy, AusNet, ARENA, AGL.

13 Submissions to the March 2020 Discussion paper: CEIG, ENA, ARENA, WSP and Energy Australia.

14 Submissions to the March 2020 Discussion paper: WSP, TasNetworks, Hydro Tasmania, ENA, CEIG, Ausnet.

15 Submissions to the March 2020 Discussion paper: ENA, EnergyAustralia, CEIG, Ausnet.

16 Mondo, Reach Energy, Energy Queensland and AGL.

17 This group is made up of representatives from generators, network service providers, AEMO, AER, ARENA, CEFC and investors to gain a cross-section of industry's view on issues in a timely manner.

2.3 System strength's role in the power system

In an alternating current (AC) power system, voltages (and currents) alternate between positive and negative values. The "voltage waveform" is a visual representation of this alternating pattern over time and will take the form of a sinusoidal wave. The "strength" of the power system can be observed in the ability to maintain the shape of the voltage waveform. That is, system strength in a location is a measure of how resistant the voltage waveform is to changes in the power system. The power system changes that can affect the voltage waveform can be both:

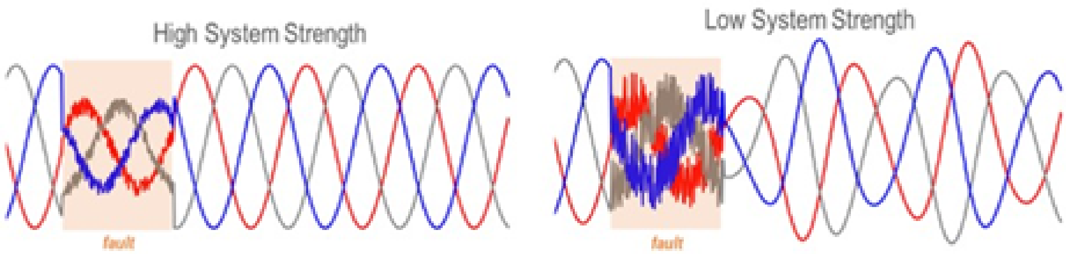
- big — like a fault on a line occurring and being cleared, or a line being switched in or out, or
- small — like a generator ramping up.

Generally, we describe the power system as being "strong" or "weak", on the basis of how the voltage wave form is maintained when either of these kinds of disturbances occur:

- A strong area of the power system will:
  - observe a relatively smaller change in voltage when a disturbance occurs
  - filter out any distortions to the voltage waveform of the system in a controlled and quick manner
  - effectively host inverter connected plant that will remain synchronised to the system, and will not create instabilities by amplifying the disturbance.
- A weak area of the power system will:
  - observe voltage waveforms that may be very 'noisy' and unstable — meaning they may quickly jump up or down (or sideways) by large amounts — making it hard for generators, particularly those connected by inverters, to stay connected, synchronised to the power system and to operate correctly
  - be vulnerable to poorly controlled faults and generator disconnections that can lead to cascading failures.
  - have increased risk that voltage waveform instabilities will be caused by poorly tuned inverters. This is analogous to the way a microphone positioned too close to its speakers can create a feedback loop that results in a loud screech.

In other words, a strong area will have stable voltage waveforms that are relatively smooth and consistent, while a weak area of the system may have unstable waveforms that may oscillate unpredictably, become deformed or change rapidly. This is shown graphically below in Figure 2.1.

Figure 2.1: Comparison of a strong and weak voltage waveform



The difference in voltage waveforms during and after a fault for systems with high and low system strength (stylised representation)

Source: AEMO, *Energy Explained: System Strength,* 15 July 2020, https://aemo.com.au/newsroom/energy—live/energy—explained—system—strength

The shape of the voltage waveform at a point in the power system is determined by all the outputs of the IBR generation nearby and the topography of the network itself. In other words, the stability of the waveform is determined by the interactions between generators and the rest of the power system, not just the characteristics of individual generators or network equipment.

The interrelated nature of factors influencing system strength makes it difficult to isolate the exact cause of system strength issues to individual participants or, conversely, assess the exact system strength contribution of individual solutions. Instead, all plant and network components in the relevant area of the network must be taken into account when assessing impacts or solutions to system strength. Therefore, a holistic approach to system strength requires visibility and coordination of the multiple parties operating in different areas of the power system.

2.4 Evolved description of system strength in the NEM

The Commission has developed a description of system strength that aims to clearly define and bound the relevant physical power system issues currently arising in the power system. This section sets out this evolved description.

2.4.1 System strength as voltage waveform stability

As noted above, AEMO currently defines system strength as: [18]

"*the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance*."

This definition broadly describe the area of power system engineering to which system strength relates - voltage waveform. However, it was considered that did not adequately

18 AEMO, Renewable integration study — stage 1 report, April 2020, p.50.

resolve the different perspectives surrounding the term 'system strength' and the resulting stakeholder confusion of the exact nature of the service.

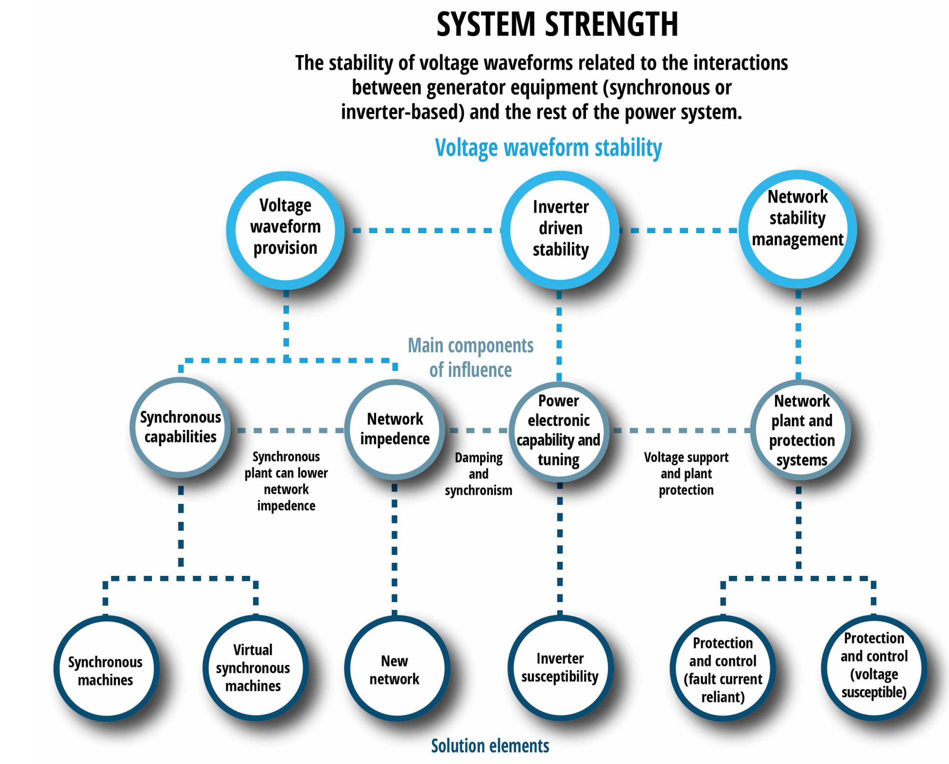
As such, one of the purposes of this is to develop a more granular working description of system strength that breaks down the power system concepts that constitute system strength and the power system characteristics that influence it in the power system. The below definition reflects AEMO's feedback. This definition is used throughout the rest of this report i.e. every time system strength is referred to, we mean:

"the stability of voltage waveforms related to the interactions between generator equipment (synchronous or inverter-based) and the rest of the power system."

Voltage waveform stability includes a number of power system effects and outcomes. These occur both at the power system level and at the individual generating unit. The individual physical issues that influence voltage stability must be identified in order to effectively address system strength concerns in the power system.

Figure 2.2 below provides an overview of the key voltage stability concepts that underpin system strength and the characteristics of the power system that influence each of these concepts.

Figure 2.2: System strength overview — voltage stability concepts



Source: AEMC

The three voltage stability concepts are key in defining and understanding the problem definition of system strength. That is, these are the physical issues experienced in the power system that must be addressed to improve system strength. Appendix A explores system strength, its components and their interactions in more detail.

2.4.2 The three key voltage waveform stability concepts

There are three key power system concepts that determine the stability of voltage waveforms in the power system.

- **Voltage waveform provision —** The supply of a 'strong' voltage waveform into the power system is the 'source' of system strength. This is the backbone reference signal on which the system operates.
- **Inverter driven stability —** Disturbances in the system need to be positively damped towards a stable steady state, through the actions of both network equipment and connected generating plant. This includes the stability of inverters and their interactions with other inverters and the rest of the power system.[19]
- **Network stability management –** Network plant and equipment require adequately damped voltage waveforms to operate effectively. This includes the need to provide fault current to operate protection mechanisms for fault management.

These three components are separate physical phenomena that result in separate outcomes on the power system. However, each component added together is relevant to the level of voltage waveform stability, and therefore the "strength" of the system. Enhancing outcomes for one component may, to some extent, make up for a lack of another, to result overall in an adequate level of voltage waveform stability in the power system.

These relationships can be summarised as follows:

- There is some level of **substitutability** when addressing system strength through each of these components, affording some level of flexibility to potential solutions.
- There is also a level of **interdependency**, meaning that the provision of system strength requires each of these components to be addressed to some extent. System strength cannot be provided through changes relevant to one component alone.

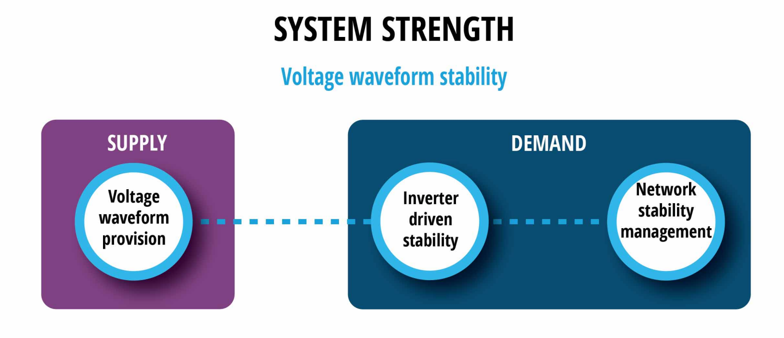
These three voltage stability concepts are key in defining and understanding the problem definition of system strength. That is, these are the physical issues experienced in the NEM that must be addressed to improve system strength. Appendix A explores system strength, its components and their interactions in more detail.

19 This component was previously referred to as small and large angle stability in the System Services consultation paper (AEMC, *System services consultation paper,* July 2020, pg. 51). The AEMC has determined that this component is better referred to as 'inverter driven stability' to better reflect the active role of grid following inverters in determining system strength and to better align with CIGRE and NERC's power system stability concepts (see Appendix A). The *System Services consultation paper* was published on 2 July 2020 and consulted on six rule change requests that relate to system security services. In particular, the paper consulted on the Efficient management of system strength on the power system rule change request by TransGrid and the Synchronous services market rule change request by Hydro Tasmania which both related to system strength.

2.4.3 Supply and demand of system strength

Broadly, the three key voltage stability concepts explored above can be expressed in terms of the *supply* and *demand* for system strength services, as indicated in Figure 2.3 below.

Figure 2.3: System strength concepts as supply and demand of the service



Source: AEMC

The voltage waveform stability of an area of the grid is dependent on the proportion of the *supply* of a strong voltage waveform, to the *demand* for a strong voltage wave form from inverter based resources (IBR) that require stable voltages to stay effectively connected to the power system. This proportional relationship means that an overall improvement to voltage waveform stability may be achieved by *increasing* the provision of strong voltage waveforms (by taking actions like turning on a synchronous generator) or by *decreasing* the impact of inverter—connected generators (by taking actions like disconnecting some inverters of a non-synchronous generator). Supply of system strength for network stability, which effects both inverter connect plant and network equipment, can also be supplied by lowering network impedances. This can be achieved by building new network assets or synchronous machines.

Similarly, the operation of protection mechanisms requires a certain level of voltage stability to operate correctly and, for network protection mechanisms, a certain level of fault current. However, certain sensitivity tuning or changes in equipment may reduce the amount of voltage stability or fault current the protection mechanism requires.[20]

2.5 Measuring and assessing the need for system strength

Given that system strength consists of the three components above, and that these components can be split into *demand* and *supply*, we can then consider the overall "need" for system strength - how much needs to be supplied, on the basis of how much is demanded. However, to do so, we also need a way to measure each component. Such a

20 Network stability management includes the supply of short circuit fault current, which is not the same as voltage waveform provision. Technologies that traditionally provide voltage waveform provision also provide fault current, however this is not the case for virtual synchronous machines. That is, theoretically, a virtual synchronous machine may satisfy the supply requirements for voltage waveform provision but not satisfy fault management requirements.

measure then allows us to consider the extent of substitution, or trade offs, that may occur between each component.

Therefore, two key complexities arise in developing frameworks for system strength, based on the problem statement and its broad components, which are:

- measuring system strength as an explicit unit(s)
- assessing how system strength is required in terms of 'services'[21] to meet power system needs.

2.5.1 Difficulties in defining a single metric for system strength

Measuring any trade-offs that may exist between each key voltage stability component requires a metric, or metrics, that capture the physical contributions of supply and the impact of demand. Historically, fault level (expressed in MVA) has formed a proxy unit of measurement for system strength. However, while fault level may be an effective measure when considering fault management, this is only one component of system strength when described in terms of voltage waveform stability.

An appropriate metric for system strength would allow the responsible party to directly define success criteria for adequate system strength. At a high level, the desired system voltage stability outcome is appropriately damped changes to voltage magnitude and phase angle, including damping time limits for oscillatory responses. Voltage waveform stability needs to be achieved both in areas of the power system that host large volumes of non-synchronous generation, and in areas distant from generation where correct network operation is the driving demand factor.

A metric, or metrics, is therefore needed for both the supply and demand components, in order to assess whether this outcome will be met in the power system. Such a metric must both represent the magnitude of contribution to voltage waveform stability and be practical to apply, measure and forecast.

To identify options for a useful metric, voltage waveform can be examined in terms of the contribution or impact of its active and passive components:

- **Passive:** The passive portion of voltage waveform stability refers to the static damping characteristics of the network, determined by the network's impedance. Impedance can be directly measured or captured through proxy metrics such as fault current or SCR (short circuit ratio). The automatic responses of network protection mechanisms can also be captured under the passive portion of voltage waveform stability. As described above, the "demand" from these mechanisms is a measure of fault current.
- **Active:** The active portion of voltage waveform stability refers to the interaction between the supply of strong voltage waveforms and the dynamic behaviours (demand) of the control systems of IBR. The effect these active portions of system strength have on system strength are dependent on a multitude of factors and so are difficult to reflect with a simple metric.

21 Service in this context refers to a way parties can contribute to system strength generally. This is not necessarily limited to or include dynamic market ancillary services such as the provision of FCAS.

2.5.2 Approximate metrics for system strength

Improving the passive stability of the system, that is lowering network impedance, positively affects all three key components of system strength. That is, it can improve the 'supply' of system strength and decrease the impact of the 'demand'. Such an improvement could be measured directly (Ohms) or through related proxy measurements (SCR or fault current). However, a different or additional metric is needed to take into account the value of changing the active components of system strength.

As the effects of the active components are difficult to measure discretely, a passive impedance measure may instead need to be paired with more general, outcome based voltage stability performance criteria for a system strength contributions or impacts to be assessed comprehensively. Limits on voltage magnitude changes, phase angle changes, and damping times may be useful in this way.

The Commission's explorations of possible metrics for system strength is explored further in Chapter 4 and Appendix A when considering how a planning standard for system strength could be defined. The Commission — in collaboration with ESB, AEMO, AER and our technical advisers GHD, as well as through engagement with industry — is continuing to investigate effective ways to measure system strength.

3 OVERVIEW OF EVOLVED SYSTEM STRENGTH FRAMEWORK

The Commission has used the description of system strength set out in the previous chapter as the basis on which to evolve the regulatory frameworks for system strength. This has focused on system strength in investment timeframe; operational considerations are being considered by the ESB in its 2025 work. The development of this framework has incorporated significant stakeholder input provided through an extensive consultation program[22] as well as collaboration with the ESB, AEMO, the AER and our technical consultants GHD.

This Chapter sets out the:

- key elements of our evolved system strength regulatory framework
- the analysis underpinning this framework, including how it addresses the identified issues with the current framework, and the basis of the three elements of the framework

The recommendations for an evolved framework have been developed and focus on addressing the most critical elements associated with system strength in order to reduce the costs faced by participants, and ultimately consumers. However, system strength is an evolving concept as the previous chapter has illustrated, and the Commission acknowledges future evolution to this framework may be required, to continue to make sure the arrangements deliver efficient outcomes for consumers.

On this basis, this Chapter concludes by setting out some other issues that we consider will likely warrant further attention in the future. We intend to continue to work with the ESB, AEMO and AER and stakeholders in order to progress these issues.

3.1 Stakeholder feedback to evolve the frameworks

The Commission received 31 submissions to the Discussion paper. These submissions assisted the Commission better understand the issues that have emerged with the existing arrangements since its implementation in 2017, as well as industry's thoughts on how to best evolve the frameworks to be more effective and efficient.

The key points the Commission heard from stakeholders were:[23]

- The definition and magnitude of the minimum levels of system strength may need to be revised, to recognise the changing power system needs of a transitioning NEM.
- The framework may not efficiently allocate responsibility between AEMO and TNSP in meeting the minimum level, outside periods of normal operation.
- The framework is reactive, and may not always effectively identify and instigate remediation of system strength shortfalls sufficiently far in advance.

22 This consultation included consideration and follow up on stakeholder submissions to both the March 2020 *System strength investigation: Discussion paper* and July *System services consultation paper*; four technical working group sessions with a broad range of industry participants; direct engagement with jurisdictional energy departments; and bilateral briefings with multiple stakeholders.

23 Stakeholder submissions to the Discussion paper can be found here: https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem.

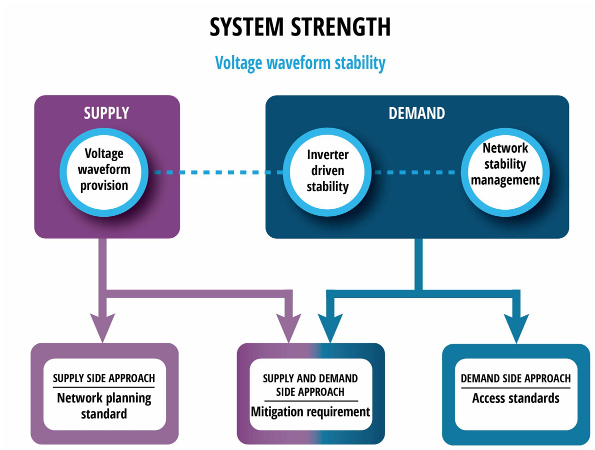
- Stakeholders noted that the need to evolve the current 'do no harm' arrangements, as concerns have emerged about it acting as a potential deterrent for new entrants.

3.2 The evolved system strength framework

The framework set out below will provide an efficient level of system strength, to keep pace with the transition already underway in the power system, promoting the long-term interests of consumers. The recommended framework has three key components:

1. **Supply side:** a new system strength planning standard that sets an efficient level of the service (i.e. that which maximises the benefits to consumers, relative to the costs, of system strength in the system). TNSP's must provide system strength to meet this standard, through the structured procurement of network (such as building assets like synchronous condensers) and non-network (such as contracting with synchronous generators or retuning inverters) solutions. This will be implemented by amending the existing minimum system strength framework to make it more proactive and move away from the concept of providing "minimum" levels to address system strength shortfalls.
2. **Demand side:** two new access standards that new connecting generators will have to meet, in order to manage the system strength requirements of grid following inverter-based resource (IBR) generators by mandating a base level capability for each inverter connecting in the NEM.
3. **Efficient coordination of supply and demand - System strength mitigation requirement (SSMR):** to coordinate and manage the interactions between the demand and supply side by evolving and amending the existing 'do no harm' arrangements to better reflect the changes in the supply side reforms such that price signals for investment and location are sent to generators in an efficient and effective manner.

Figure 3.1: Evolved system strength description into the evolved framework



Source: AEMC

This framework is an evolution of the existing system strength frameworks. It has been developed through this review, as well as through the AEMC's ongoing collaboration with the

ESB and other market bodies. It is consistent with the ESB's Post 2025 market design work program, in particular, the essential system services work stream for which an update was provided in the recent ESB consultation paper.[24]

The following sections set out the context that has informed the recommended evolved framework, specifically the ESB's Post 2025 Market Design project. We then step through the reasoning and analysis that underpins the three components of the evolved framework, and how the framework addresses the issues raised with the existing arrangements.

3.2.1 Structured procurement for system strength

As set out in the ESB's consultation paper for post 2025 market design, spot markets represent the theoretically optimal way to procure system security services. This is because a spot market approach maximises the value of procurement, by sending clear price signals to participants. When the price is high, it incentivses suppliers to supply more of the service and for consumers to consume less - and vice versa.[25]

However, there are difficulties associated with procuring system strength through a spot market-based approach. These difficulties were discussed by FTI Consulting, in its assessment of system strength market design characteristics to inform the ESB Consultation paper.[26] FTI's general assessment was that system strength was not amenable to spot market based procurement framework, as described in Figure 3.2 below.

Firstly, this was on the basis that the highly locational characteristic of system strength, coupled with the fact that there are often only a small (and decreasing) number of participants that can provide system strength as a service, means that competition in the supply of this service may be limited. This in turn reduces the effectiveness of a spot market approach to drive efficient outcomes.

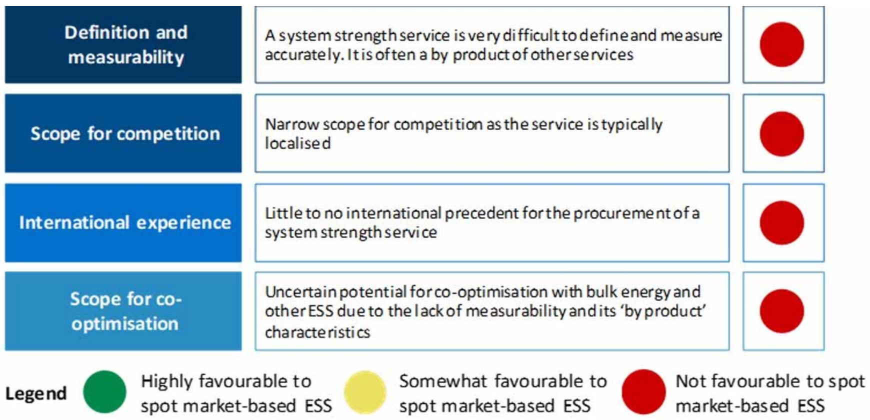
Secondly, another core complexity for a system strength spot market arises from the fact that the service doesn't have a single, measurable metric that can be used as the basis for a demand curve for a market, as noted in Chapter 2.

24 Energy Security Board, *Post 2025 Market Design: Consultation Paper*, September 2020.

25 Additionally, it allows for full co-optimisation between services and between services and energy. This could provide both more efficient dispatch and pricing of services, and potentially drive innovation in the provision of various combinations of ESS from different technologies including DER.

26 FTI Consulting, *Essential System Services in the National Electricity Market*, 14 August 2020.

Figure 3.2: Assessment of system strength market design characteristics



Source: Energy Security Board, *Post 2025 Market Design Consultation Paper, September 2020*, p. 70. Original analysis by FTI Consulting.

Given these factors, the ESB recognised that "some services do not currently appear capable of being procured in a real-time spot market (e.g. elements of system strength)." On this basis, the ESB found that "regulated/structured provision may be an efficient answer for some time, particularly for capital intensive or lumpy investments."[27] This could include the procurement of the service by a market operator or network service provider, as well as through mandating technical requirements for generators. Several examples of this type of structured procurement already exist under the existing arrangements for system services, including the minimum inertia and system strength frameworks.

The next section sets out some examples, provided by the ESB, of what these structured procurement mechanisms might look like.

3.2.2 Options for structured procurement

Regarding system strength, there are three main structured procurement arrangements set out in the ESB Consultation paper:

1. **TNSP provision of system strength.** Such an approach would build on the existing obligation on NSPs to provide system strength to a defined level. This approach falls within the existing NSP planning processes and can provide benefits of economies of scale as well as scope, because TNSPs have the option of entering into contracts with existing resources to provide system strength, or making necessary investments (such as synchronous condensers or network augmentations) under relevant investment tests. The scheduling and enablement of the service would remain be AEMO's responsibility.
2. **Bilateral forward contracting between AEMO and providers.** Contracts for system strength provision may take the form of procurement through multi-year contracts for resources (including synchronous generators and synchronous condensers) to come

27 Ibid, p.71.

online when instructed to do so by AEMO. AEMO would also need to identify system strength requirements over the relevant contracting horizon. Existing examples of this approach include the SRAS and NSCAS frameworks.

3. **Mandatory technical limits.** Placing technical requirements on parties to:
   a. reduce the demand for additional system strength services created by new connecting IBR generators, and / or
   b. remediate shortfalls of system strength.

The AEMC set out similar options to this in our March Discussion paper. Options 1 and 2 above are broadly consistent with *Model 1,* the centrally co-ordinated approach set out in the March paper. Option 3 is most consistent with *Model 3,* the mandatory service provision model that we set out in the March paper.[28]

Building on the framework set out by the ESB, the Commission considers that the main mechanism for the 'supply' of system strength should be a mechanism based on Option 1, being a model for the coordinated provision of system strength, where TNSPs play the central procurement role. This reflects that relatively incremental changes can be made to the existing structured TNSP procurement approach - represented by the minimum system strength framework - to effectively and efficiently evolve the system strength framework as set out below in section 3.3.

Additionally, the Commission considers that a limited use of Option 3, Mandatory technical limits, should be used to introduce a '"demand side' of the evolved framework, to complement the 'supply' side approach.

More specifically, the evolved framework will include the following:

- Option 3a (reducing demand through technical requirements) should be utilised to manage the demand for system strength, as set out in section 3.4.
- Option 3b (active remediation of system strength impacts), will be used to send some locational signals to generators, based on their marginal impact on system strength services, as set out in section 3.5, and will address the issues with the current do no harm arrangements.

These components of the evolved framework are described below, with more detail the provided in Chapters 4, 5 and 6.

3.2.3 The evolved framework's service design framework

The Commission has used our service design framework to set out how the system strength will be planned, procured, priced and paid for under the evolved framework, and is set out below.

28 Many stakeholder submissions to the AEMC Discussion Paper were supportive of a co-ordinated structured procurement approach, similar to Model 1; 26 submissions out of 31 were supportive of *Model 1* being used for the provision of system strength in the NEM

Figure 3.3: How the evolved framework plans, procures, prices and pays for system strength

1 PLAN

AEMOs periodic system strength guidance material would account for determining and updating the standard by providing key inputs in relation to:

- the location of nodes
- the available fault level at each node
- where and when the TNSPs will meet the standard.

TNSPs transmission annual planning review and reports (TAPR) would account for providing:

- forecast entry and exit of generation
- joint system strength studies and forecasts with AEMO
- an indication of the location of high system strength areas
- an indication of the types of connection charges connecting.

Generators will plan their connections based on the information provided by AEMO and TNSPs. Requirements of access standards will be specified in the rules with the required levels negotiated during the connection process

2 PROCURE

TNSPs would undertake the RIT-T process to procure the net beneficial option, or combination of options (both network and non-network) to meet the standard and also consider opportunities to co-optimise with other network services as part of this process.

Generators connecting in strong system strength areas would undertake PIA assessments to identify the amount of system strength it needs to "procure" under the new system strength mitigation requirement to remain stable.

Generators connecting in weak system strength areas would undertake FIA assessments to identify the extent of their remediation requirements.

3 PRICE

The price paid by TNSPs to procure system strength to meet the standard will be an outworking of proposed reforms and the TNSPs obligation to meet the new standard. The RIT-T process will encourage TNSPs to procure net beneficial options.

Under the proposed system strength mitigation requirement generators will pay a price based on marginal costs which is widely regarded to be an important principle in promoting efficient outcomes. Pricing is based on the long run marginal cost of adding an additional MVA to the system.

4 PAY

Inverter-based generators will pay a marginal cost-based charge based on a dollar per system strength unit multiplied by the electrical distance factor from the node. Residual costs not recovered by marginal cost charge will be recovered from consumers.

Source: AEMC

3.2.4 How the evolved framework addresses the issues raised

In the March Discussion paper, the Commission set out numerous issues that had arisen with the existing system strength framework since its implementation in 2017. These issues have been further evidenced by discussions and input from AEMO and stakeholders since that time, particularly drawing from the experience of the West Murray zone.

While the existing frameworks have been successful at keeping the power system secure, the power system has observed new challenges emerge and the industry's understanding of system strength evolve as the power system has itself changed. The Commission acknowledges that the pace of the NEM power system transition means the time has now come to adjust and expand these frameworks. The changes required to the frameworks will need to reflect the change in the generation mix that is underway, and the move to large numbers of new non-synchronous IBR generation.

Figure 3.4 below shows the issues with the existing arrangements, mapped against the elements of the evolved framework - that is the supply side, demand side and SSMR - that addresses those issues.

Figure 3.4: How the evolved framework addresses issues raised with the existing framework

Existing framework	Issues with the current framework to be addressed	Elements of the evolved framework that address issues		
		Supply side	Demand side	SSMF
Minimum system strength framework	Clarifying the definition of system strength	★	★	
	Difficulty in procuring levels higher than the minimum	★		★
	Reactive approach to system strength procurement	★		★
'Do no harm' framework	Delays in the connection of IBRs related to system strength	★		★
	Investment certainty for IBRs due to unforeseen remediation costs	★	★	★
	Economies of scope and scale not easily realised	★	★	
	Unclear obligations between TNSPs and AEMO	★	★	★

Source: AEMC

The proactive network provision of system strength will result in more system strength being provided in the system, as contrasted to the current minimum levels procured under the existing arrangements once a shortfall has been declared by AEMO. This will in turn increase the amount of system strength available in the system to facilitate the efficient connection of new IBR generation.

3.3 Supply side: Coordinated approach to provision of system strength

At a high level, the Commission considers that system strength should be supplied as a network service. Our recommended evolved framework therefore maintains TNSPs as the procurer of system strength, but has AEMO playing an important role in providing guidance.

In procuring system strength, the TNSP would be obligated to meet a system standard. This standard will be defined in the NER, but the way in which it is applied by TNSPs would in turn be guided by AEMO. AEMO would do this through its modelling of key requirements that the standard should meet - such as levels of forecast IBR generation connecting to the network, and the forecast available fault level, as part of the integrated planning process. The TNSP would also be subject to the existing economic regulatory frameworks, with the AER playing a key role in guiding how the TNSP meets its obligations.

Broadly, the core elements of this co-ordinated supply side approach include:

- Recognises the shift from a centralised, synchronous generation fleet - where system strength was a by-product of energy generation - to an increasingly decentralised, non-synchronous fleet, where the service is not inherent, but is nevertheless critical to stable operation of the power system as a whole.

- Recognises the difficulties in creating a dynamic, spot market-based procurement mechanism for system strength in the medium term, as described above. To address these issues, it utilises a TNSP structured procurement approach.
- Allows for all the solutions to provide system strength to be effectively considered. This includes allowing for the system strength services from synchronous generation to be valued, through enabling TNSPs to contract for these services as a non-network solution, while also allowing for network solutions to be utilised where they are lower cost.

Under the evolved framework, TNSPs will have the obligation to provide system strength services, and may use network or non-network solutions to provide these services. Given that the assets that provide these services will have operational implications, we consider that AEMO coordinate and control (in some form) these solutions in the operational timeframe through the dispatch process. This aligns with current arrangements, and is necessary to ensure that the power system is maintained in a secure operating state. We will develop the specifics of these mechanisms to provide AEMO with operational control both through the draft determination of the TransGrid rule change request and the ESB Post 2025 market reform project.

This section expands on this reasoning and explains the Commission's rationale for why system strength should be provided through a coordinated model, that utilises TNSP procurement, subject to the integrated planning framework administered by AEMO.

More detail of the supply side model is then provided in Chapter 4.

3.3.1 Benefits of this approach

There are a number of benefits associated with a coordinated model that make it the most efficient and effective way to evolve the system strength supply side, promoting the long-term interests of consumers.

These benefits include the following:

- **AEMO can utilise the ISP to forecast the future needs of the system:** AEMO would build off its modelling studies carried out in the ISP to inform the amount, type and location of resources connecting to the network. This can then be used for more detailed assessments in its system strength report, which details the available fault level over a future horizon. This central role in forecasting builds off the existing integrated planning processes.
- **Efficient, proactive procurement of the service:** Currently AEMO has to forecast the *typical dispatch patterns* of generation to calculate the minimum system strength requirement and therefore identify if a shortfall of the service will occur. This is a complex task for AEMO to undertake and ultimately has resulted in an inefficient, reactive framework. This reflects the significant difficulties associated with accurately modelling typical dispatch patterns, and predicting likely shortfalls, with sufficient time for TNSPs to procure the required services. The evolved supply side framework recommends

establishing a system strength standard that will require TNSPs to procure system strength to a level higher than the minimum, without a requirement to account for the system strength expected to be provided as a byproduct of energy production from synchronous generators under *typical dispatch patterns.* This means that TNSPs will be procuring the "full amount" of services needed to meet expected system strength needs, rather than procuring only those additional volumes on top of what is assumed to be already provided through expected patterns of synchronous generation dispatch. As a result, the TNSP will have to proactively procure system strength services ahead of when a shortfall occurs, to provide levels above the minimums required to maintain security alone, as is currently the practice under the existing arrangements.

- **The recommended framework allows for competitive provision of system strength from existing generators:** A TNSP procurer will be able to meet its system strength obligations through using the existing processes for utilising network or non-network solutions. This process, which is established and subject to existing regulatory processes, will allow for existing generators to offer to provide system strength services. These will then be utilised by the relevant TNSP, where this offers the lowest cost solution to meeting their regulatory obligations.
- **The proactive approach unlocks economies of scope:** Many of the assets that provide system strength can also provide other system services. For example, synchronous condensers can provide reactive support (voltage control), in addition to providing system strength. TNSPs are well-placed to capture these scope economies through their existing planning processes for meeting other system standards.
- **System strength provision can be co-optimised with the role of transmission line augmentation in providing system strength:** TNSPs are responsible for making significant investments, to meet their various obligations - in particular, investments in new transmission assets. In making these large investments, TNSPs are able to consider any positive externalities / scale economies that may exist that allow for the provision of other services that flow from the build out of transmission line assets. This is particularly relevant to system strength, given that reductions in transmission line impedance is relevant to the stability of the voltage waveform, and the strength of the system.
- **System strength provision allows for consideration of scale economies:** As the counterparty to the connection of all new generation, TNSPs are also well positioned to exploit scale economies in the provision of centralised assets to provide the system strength to support these new connections. Subject to guidance from AEMO through the coordinated planning processes, TNSPs are well-placed to "rightsize" provision of system strength services, by exploiting any available economies of scale.
- **Established planning processes allow for the lowest cost combinations of options to be considered:** Working closely with AEMO and the AER, TNSPs have extensive experience in planning for the long term needs of the power system, and identifying the lowest cost solutions to meet these needs. System strength is a service that will become increasingly critical to both the security and economic efficiency of the system in the coming decades; utilising the existing planning processes will allow for all the relevant parties to identify those long term solutions, or combinations of solutions, to

deliver this service at the lowest possible cost for consumers. This includes contracting with existing synchronous generators or synchronous condensers, as has occurred under the existing system strength arrangements.

The nature of these benefits is discussed in more detail in the box below, which explores the "asymmetry" of costs associated with procuring different levels of system strength.

BOX 2: ASYMMETRY OF TOTAL COSTS OF PROCURING TOO MANY VERSUS TOO FEW SYNCHRONOUS CONDENSERS

A critical challenge is how to determine the optimal solution(s)to meet future system strength needs. Forecasts of future needs will not always prove accurate, and so there is always the likely possibility that there may be too much or too little system strength actually provided.

An important question is therefore what are the total costs of procuring too much versus too little system strength? In particular, assuming for simplicity that the solution is to use synchronous condensers to fill gaps in system strength requirements, what are the relative risks associated with procuring too many versus too few synchronous condensers?

Determining the optimal pathway for procuring system strength

There must be some optimal level of synchronous condensers, as well as use of existing assets, for which the total system costs are minimised, noting there is always the prospect that forecast errors and unexpected changes that result with more or less synchronous condensers than is optimal. So, an important question is how total system costs change if we procure too many or too few synchronous condensers.

The Commission has done some modelling of how total system costs change depending on whether we deliver too many or too few synchronous condensers. The modelling has involved examining outcomes in a single, simplified region. The first stage of the model is to determine the optimal combination of existing generation, new renewable and thermal plant, as well as synchronous condensers to:

- meet all standard dispatch constraints (eg, supply-demand balance, minimum and maximum generation constraints etc);
- satisfy minimum system strength constraints for sub-regions of the region; and
- allow hosting of renewable generation capacity, subject to limits arising from the amount of system strength in each sub-region.

Having determined the optimal level of synchronous condensers, the second stage of the modelling involved assessing how total system costs change when we alter the number of synchronous condensers in the system. In particular, we have modelled how total system costs are altered when we build fewer and more synchronous condensers than optimal.

There are three key observations from the modelling.

1. Synchronous condensers provide diminishing marginal benefits

The first observation is that synchronous condensers provide diminishing marginal benefits –

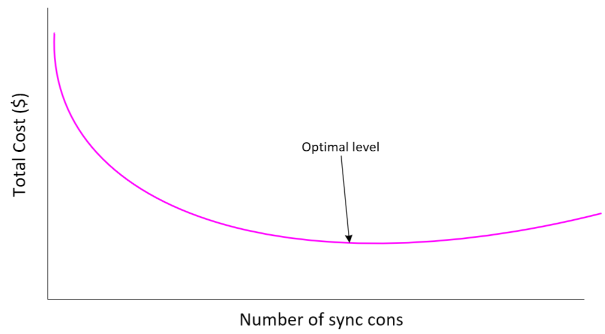
the reduction in total costs arising from the second synchronous condenser installed is less than the first synchronous condenser installed. The benefit comes in the form of lower dispatch costs. But as we increase the number of synchronous condensers, eventually costs flatten out and more synchronous condensers provide no additional value.

2. Synchronous condensers have constant marginal costs

Although the benefits of synchronous condensers vary depending on how many synchronous condensers are in the system, the costs are constant. Put simply, the next synchronous condenser costs the same as the last synchronous condenser.

This is an obvious but important observation, because when we combine the cost curves for dispatch costs and synchronous condenser costs, it yields the total cost curve shown in Figure 1.5. We can see that the total cost curve falls sharply as we approach the optimal level – ie, the point on the curve where total costs are minimised – and then slowly start to rise again.

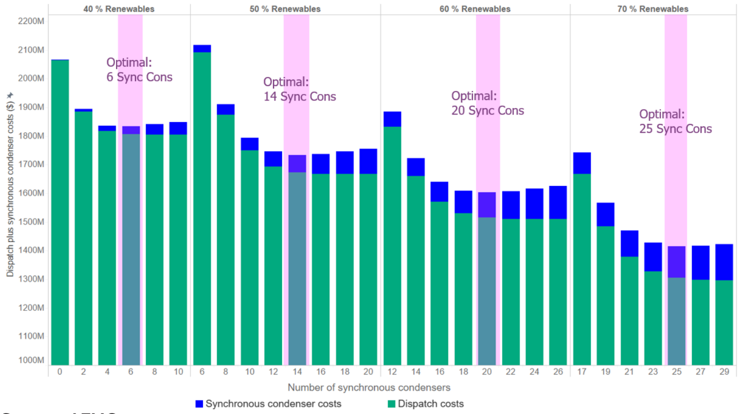
Figure 3.5: **Illustration of constant marginal cost of synchronous condensers**



Source: AEMC

The important feature of Figure 1.5 is the asymmetry between having too few synchronous condensers and having too many. This is the result that is borne out by our modelling. Figure 1.6 shows the results of our modelling and the clear asymmetry in costs between having too few synchronous condensers and too many, for different assumed levels of IBR generation penetration.

Figure 3.6: Total costs and number of synchronous condensers for various levels of renewable penetration



Source: AEMC

3.3.2 Other considerations in relation to this approach

While the Commission considers that a coordinated, network-procurer model is the best approach for an evolved framework, it is acknowledged that other options exist which could be used as the basis of an evolved framework.

Other potential structured procurement models

In considering other models that could be used to inform a coordinated approach to provision of system strength, the Commission considered whether some form of market operator-led procurement model might be a viable solution. In considering these options, we explored changes to the existing NSCAS framework, or the potential for some new, bespoke AEMO procurement framework.

The Commission recognises that AEMO have an important role to play, as system planner and operator, in looking at the system in an integrated manner and determining the efficient level of system strength. However, we also consider that AEMO may be less effective as a procurer of system strength, in contrast to TNSPs, for the purposes of providing system strength in investment timeframes.

Firstly, AEMO is less likely to have natural access to the full suite of solutions that could be used to provide system strength, as opposed to a TNSP. While an AEMO procurement model could effectively utilise solutions provided by synchronous generators, it is less likely to be able to effectively utilise the full suite of options that would be available to a TNSP. For example, AEMO would not be well-placed to leverage solutions such as coordinated retuning of existing generators. Similarly, AEMO would not be in a position to effectively exploit the economies of scale available to a TNSP, through measures such as coordinating provision of system strength with augmentation of high voltage transmission lines.

The Commission also considered whether some more limited form of AEMO procurement, such as an adapted NSCAS model, might form the basis of the evolved framework. We decided against this approach on the basis of the various structural limitations associated with the NSCAS framework identified in the Discussion paper, including its reactive, ad-hoc nature and the significant time delays associated with its implementation.[29] When coupled with the fact that the recommended framework will proactively provide efficient levels of system strength, it follows there is a reduced need for an ad-hoc, reactive framework like NSCAS to fill system strength gaps (that is, the gaps should not arise in the first place).

The Commission recognises that in the provision of other system services being considered by the ESB, AEMO procurement is still an option.

Potential for capex bias

Several stakeholders have raised concerns that the potential capex bias of TNSPs might form an impediment their effective procurement of system strength services.

A concern from stakeholders on TNSP provision of system strength to date has been a perceived capital expenditure bias that exists. That is, it is suggested that TNSPs have a bias towards meeting their obligations through the use of capital expenditure rather than through the use of operating expenditure.[30]

In relation to this issue, the AEMC noted in the *Electricity network economic regulatory framework review 2019:*[31]

> *The Commission notes the risks of expenditure bias are less in the current environment. Networks have a limited ability to source investment funds at a rate significantly lower than the regulated rate of return given historically low interest rates. Demand for network services is generally flat and capex spending across the sector is at relatively low levels...*
>
> *In the future it is expected that there will be a greater substitution possibility between capital expenditure (capex) and operating expenditure (opex) solutions. As discussed in the 2018 Economic regulatory framework review report, technologies such as DER, grid-scale batteries or pumped hydro can provide a range of services to multiple participants in the energy sector, including services that are valuable to networks to help them manage technical issues on their networks or reduce peak demand. As a result, networks will increasingly be required to make choices on whether to undertake traditional poles and wires capex investments or to use opex to procure alternative services from third parties.*

However, the Commission recognises that this is a concern for stakeholders and will give further consideration to this issue as we progress towards making a draft determination for the TransGrid rule change request. In particular, the Commission is concerned about the

29 AEMC, *Investigation into system strength frameworks in the NEM, Discussion paper,* March 2020, pp. 68-69

30 In relation to system strength this may manifest itself as building synchronous condensers rather than contracting with synchronous generators.

31 *AEMC, Electricity network economic regulatory framework review 2019, Final report, p. 67.*

situation where system strength requirements are urgent and there are limited options available to the TNSP - this may mean that incumbent generators may be able to offer inflated prices. The Commission has set out its thoughts on this in Chapter 8.

3.4 Demand side: new generator performance requirements to manage system strength needs

System strength is a finite resource. As such, connecting generators should be required to use it as efficiently as possible. Managing the 'demand' for system strength from new connecting, grid following IBR generators will reduce the costs on consumers to facilitate the connection and operation of these generators.

This can be done by utilising the well-established generator access performance standards and existing NER definitions. We have therefore recommended the introduction of two new access standards, including new standards for short circuit ratio and phase shift on terminal voltage. We will also give further consideration to the potential for reforms to the damping requirements for generators in the NER, and whether these requirements can help to manage the overall demand for system strength.

These represent relatively minor changes to the existing generator access standards, while setting a good baseline for future generator capability. We expect that a key benefit of these reforms will be to reduce the total amount of system strength "demanded" by connecting generators, helping to keep costs low for customers. Another benefit will be that in future more generators connected in the NEM will be flexible and capable of operating in environments with lower levels of system strength. This should in turn reduce the amount of system strength that must be supplied by TNSPs, and therefore lower cost for consumers.

More detail on this component of the evolved framework is provided in Chapter 5.

3.5 System strength mitigation requirement

Under the evolved framework, our recommended supply side reforms will enable TNSPs to proactively procure system strength, at levels above the minimum needed to avoid shortfalls, in order to facilitate the efficient connection and operation of generation. This means there will be a reduced need for new connecting IBR generators to incrementally procure their own system strength, at least when those generators connect in proximity to the nodes where the TNSP is proactively providing system strength. In turn, this points to a change in the way that the total costs of system strength are split between customers and generators.

The Commission considers it is appropriate for consumers to pay for some of the additional system strength that will be proactively provided by the TNSP under the evolved framework, as they currently do. This is on the basis that customers will see some benefit from these additional levels of system strength, given that means that more lower cost generation will be able to connect and be dispatched, as well as the fact that the power system will be more secure.

However, the Commission does not consider it appropriate that consumers should pay for the entirety of the system strength being provided. Efficient cost allocation - in line with cost causation principles - means that it is appropriate for generators who are the cause of costs to the system to pay some contribution towards those costs.

The Commission therefore recommends putting in place a charging mechanism that recovers some system strength costs from new connecting IBR generators, who benefit from the available fault level in the transmission network. This "system strength mitigation requirement" would recover some costs of the TNSPs investment in system strength from newly connecting grid following, IBR generators. This mechanism would minimise the risk that consumers would bear the costs relating to under utilised assets in the provision of system strength. It also means that the supply side and the demand side would be better coordinated together. It would also provide more information to generation who supply system strength about where to locate.

This mechanism would utilise a $/MVA levy on connecting generators, based on the marginal cost of the additional MVA required by the system. It will also include a locational component, to account for the electrical distance from a node (the source of system strength being maintained by the TNSP) to the generator’s connection location.

By accounting for available fault level and electrical distance, this charge would send a price signal to generators to further reduce their demand for system strength. Generators would be incentivised to reduce this charge by taking action to either locate closer to the node (reducing their consumption of system strength), or to avoid the charge entirely by obtaining greater capability to require less system strength (i.e. install inverters with grid forming capability).

This mechanism would be transparently designed and provide connecting generators with greater investment certainty in relation to the costs being faced at the point of connection.

In conjunction with this new charging mechanism, the Commission also recommends retaining the existing system strength self-remediation obligation, but only for those generators who elect to connect outside of the areas where the TNSP is required to provide system strength service under the supply side components of the evolved framework.

More detail on this component of the evolved framework is provided in Chapter 6.

3.6 Potential for future development of this work

The Commission notes that the understanding of system strength concepts as a power system requirement will be continuously refined into the future. This will occur as:

- Experience continues to be gained by AEMO, TNSPs and generators, in operating and participating in a power system with higher penetrations of IBR generation changes the power system's underlying requirements
- Technology develops that can provide these services in ways that are currently unknown, or still in the early stages of development - such as the ability of grid-forming inverters to provide services equivalent to currently defined services like inertia and system strength. This may differ to the way synchronous generation has provided these services in the past.

The Commission considers there are a number of areas where future work will likely be required, to make sure that system strength can be provided at the lowest overall cost to consumers. We look forward to working with stakeholders, including AEMO, the AER, the ESB, TNSP and market participants, to continue to develop our understanding of this complex and rapidly changing area.

While there are likely to be areas that haven't been identified yet, we consider that further exploration is warranted in the following areas:

- Potential procurement of system strength using a demand curve spot market-based approach. As noted above, this concept has been identified as the optimal long run market solution for system service provision, including for system strength.[32] Developments in inverter technology may eventually make this ideal solution possible. We will continue to work with AEMO and TNSPs to understand how this might be achieved in future.
- Further refinement of system strength metrics. This may allow for the various voltage waveform stability concepts that are currently incorporated into the definition of system strength, to be assessed, measured and provided separately, as a discrete product, in a more effective and efficient manner. Additionally, refinement of system strength metric(s) may allow for greater precision in system strength service planning, forecasting and procurement.
- New frameworks to enable the use of grid-forming inverters. Voltage source, or "grid forming" inverters are an emerging technology that may in future facilitate "virtual synchronous machines", or IBR generation that can operate in a manner that effectively replicates all of the behaviours of traditional synchronous machines. There is some promise that this technology could provide voltage waveform stabilisation services at a lower cost than installing traditional synchronous machinery.

  We have sought to keep the regulatory arrangements open to all possible technologies. In particular, we consider that the supply side components of the evolved framework should allow for TNSPs to utilise grid forming inverters (potentially coupled with batteries) to meet their system strength obligations.

  However, we acknowledge that future work may need to be undertaken to fully enable the capabilities of this emerging technology. This may consist of:

  - Further refinements to the generator access standards in NER clause S5.2.5. The access standards may need to be further refined to reflect the specific capabilities of this technology, which appears to be different to grid following IBR generation, as well as fully synchronous generation. These access standards are reviewed every five years by AEMO, with any changes then put to the AEMC as a rule change request. This next review by AEMO will occur by 2023.
  - Changes to the NEM power system operating philosophy, to reflect the fact that in a power system with a preponderance of grid forming inverters, it will be necessary to

32 Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020, p. 70.

determine which inverters "sets" the frequency and voltage of the system, and which inverters "follow".

- Further consideration of the processes for collective retuning of incumbent IBR generators. A number of stakeholders have identified that "collective retuning" of multiple incumbent inverter control settings could offer a low cost way to reduce "demand" for system strength, and therefore lower costs for consumers. The Commission considers this option can already be utilised through existing arrangements, and is aware of at least one TNSP who is exploring this solution. However, some stakeholders have identified that there is some uncertainty whether parties might be obligated to provide retuning, or whether they should be paid to do so. The Commission considers that future work may need to be done to explore whether there is any benefit in developing NER frameworks to facilitate this as a demand side solution.

The Commission considers that future development of technology will allow for some of these issues to be better explored. Further, that there are already other processes that are set up to look at some of these issues, such as the future review of the generator access standards. The Commission looks forward to further engaging with the ESB, the other market bodies, jurisdictions, consumers and industry, to fully explore what further changes may be needed to deliver a stronger system into the future.

4 SUPPLY SIDE: COORDINATED APPROACH TO PROVISION OF SYSTEM STRENGTH

BOX 3: SUMMARY OF KEY FINDINGS

The Commission considers that a coordinated approach is the most effective way to supply system strength in the NEM. We have therefore recommended an evolution to the current approach, which establishes a network planning standard for system strength.

This network planning standard will be part of the NER and would place an obligation on TNSPs to meet the standard. Utilising the existing network planning and regulatory arrangements, TNSPs would plan and procure the efficient level of system strength needed to meet the standard. That is, the amount required to keep the system secure and support the efficient level of system strength being provided. This efficient level would provide the right level of system strength to be beneficial (e.g. to enable the connection and dispatch of lower costs generation) relative to the costs of providing that system strength.

In practice, this involves the following:

- **Plan:** The planning components of the evolved framework consist of two iterative stages.
  - Stage one: AEMO will undertake an assessment, utilising information from the ISP, of the nodes within the network where the standard would apply. The outcomes of its assessment would be published as part of AEMO's annual *System strength report*.
  - Stage two: Utilising the existing network planning and economic regulatory processes, TNSPs consider how to meet the system strength requirements under the NER. TNSPs will be required to, among other things, take into account the outcomes of AEMO's assessment of nodes, and volumes of generation expected to connect at the node, as identified in stage one.
- **Procure:** There are a number of procurement options that a TNSP may consider to meet its obligations under the recommended network planning standard for system strength. This includes network and non-network options, where the TNSP assesses that they will deliver system strength at the highest net benefit in the long-term interest of consumers.
- **Price:** Under the economic regulatory frameworks, the AER sets an allowance for each network businesses that aims to ensure that consumers only pay for efficient expenditure and to incentivise TNSPs to undertake efficient decisions. This framework will act to incentivise network businesses to make decisions that are efficient, and maximise the net benefits for customers. Therefore, the 'price' for system strength will depend on these considerations. The Commission is concerned that in some markets, depending on how urgently system strength is needed, there may be a lack of options available for providing system strength, which could lead to parties seeking to charge higher costs to the TNSP

than may otherwise be the case. The Commission will continue to consider these aspects through the TransGrid rule change process.

- **Pay:** The AER determines the maximum amount of revenue TNSPs can recover from consumers over a defined regulatory control period for 'prescribed transmission services'. Prescribed transmission services, including the recommended system strength standard, are those that are regulated by the AER; currently, all of these are paid for by consumers through TUOS charges. The Commission considers that as customers receive benefits from the provision of system strength, they should bear some of the cost of providing these services. However, given that the connection of generators that demand system strength is the cause of some of these costs being incurred, such generation should also share some costs of these services as reflected in the system strength mitigation requirement (SSMR). That component is discussed further in Chapter 6, and will promote the coordination of the supply side (this chapter) and the demand side.

Fundamentally, the supply of system strength is the provision of a stable voltage waveform. A stable voltage waveform is supported by synchronous machines, including virtual synchronous machines like grid forming inverters, as well as through networks with low impedance. For the rest of this Chapter, we will often refer to the "supply of system strength" - however it is important to note that the fundamental service we are referring to is stabilisation of the voltage waveform, rather than the dispatch of synchronous machines, or the building out of the transmission network.[33]

The minimum system strength framework is the current arrangement through which the supply of system strength is maintained across the NEM.

The Commission's Discussion paper (March 2020) for this review stated that the minimum system strength framework needs to evolve. The key issues identified in the Discussion paper were that the:

- definition and magnitude of the "minimum" levels of system strength may need to be revised, to recognise the changing power system needs of a transitioning NEM;
- framework may not efficiently allocate responsibility between AEMO and TNSPs in meeting the minimum level, outside periods of normal operation; and
- framework is reactive and may not always effectively identify and resolve system strength shortfalls sufficiently far in advance.

Further, the minimum system strength framework is not linked to either the 'Do no harm' arrangements or the minimum inertia framework, making it difficult to realise:

33 The Commission acknowledges that synchronous machines are currently the primary "active" source of system strength, providing injection of fault current while also reducing system impedance, as well as stabilising the voltage wave form. However, provision of a stable voltage waveform will become the most important element of this service, given the significant volumes of IBR generation expected to connect in future. Given that other types of technologies, particularly virtual synchronous machines like grid forming inverters, can provide voltage waveform stabilisation, we have sought to keep the regulatory definitions of the service as open as possible.

- *efficiencies of scale* for addressing system strength needs across the minimum and 'Do no harm' arrangements. Currently, the impacts of each individual generator are effectively managed separately under each framework, which may hinder coordinated solutions; and
- *efficiencies of scope*, where solutions can co-optimise the provision of different services. There is no formal linkage between the frameworks, so co-optimisation of the services can only occur if a shortfall of inertia and system strength is declared simultaneously.

The Commission considers that a network coordinated approach for the supply side is the most effective way to supply system strength in the NEM. This approach establishes a new TNSP network planning standard for system strength and places an obligation on TNSPs to meet that standard and hence proactively provide and maintain adequate levels of the service in certain locations of the network. Outside of these clearly defined areas, the SSMR (an evolved 'do no harm' framework) would be in effect, as set out in Chapter 6.

Utilising the existing network planning and regulatory arrangements, TNSPs would provide the system strength needed to deliver system security in a way that maximises benefits to consumers. In other words, the 'efficient' level of system strength is that that maximises the benefits from having more system strength in the system, against the costs of providing that system strength. These recommended changes are expected to resolve the key issues identified with the existing frameworks.

The Commission will refine its recommendations as part of the ongoing *Efficient management of system strength on the power system* rule change process.

How this standard is planned, procured, priced, and paid is set out in Figure 1 below.

Figure 4.1: Overview of the supply side: A network coordinated approach

1 PLAN	AEMO would provide key inputs, such as identifying nodes where the standard will apply and determining expected volumes of new generation, which would inform where and when TNSPs will meet the standard, through the ISP process and a revised system strength report. TNSPs would then use the existing network planning and investment processes to meet the standard at lowest cost. The transmission annual planning review and reports (TAPR) would account for: • forecast entry and exit of generation, as forecast in the ISP, • The TNSP's system strength studies and forecasts based on key inputs from AEMO's revised system strength report, • each TNSP's own network limitations and connection enquiries.
2 PROCURE	TNSPs would then undertake RIT-Ts to identify the net beneficial option, or combination of options (both network and non-network) to meet the identified need to meet the standard. As part of this process, TNSPs would also be able to consider whether there is opportunity for co-optimising the provision of system strength with other network services, such as reactive support and inertia.
3 PRICE	The cost of procuring system strength to meet the standard would be an outworking of the existing regulatory frameworks. The TNSP would be provided with some flexibility to ensure that inefficient costs are avoided.
4 PAY	The costs of TNSP procured system strength would be efficiently allocated and shared between consumers, through TUOS, and newly connecting generators through the proposed system strength mitigation framework.

Source: AEMC

This Chapter steps through establishing the system strength standard and then each of the '4P' elements in more detail in relation to the supply of system strength.

4.1 Establishing a system strength standard

There are four core elements that should be considered when establishing a system strength standard. These are:

- The **metric** which is the way the service is measured for the standard. This is the *provision of three-phase fault level* under the existing framework.
- The **level** that the standard should be set at. This is the minimum amount required for a secure system under the existing framework.
- **Who** sets and administers the standard and the potential candidates and role and responsibilities of each. This is currently principally in the NER and then in detail in AEMO procedures.

- The **areas** of the NEM where the standard will apply. That is, **where** on the network the required amount of system strength must be provided by the TNSP. Under the existing framework, this is at defined *fault level nodes*.

The Commission is recommending that the network planning system strength standard is based on the four elements above. It proposes that:

- **Metrics:** The main metric to be used would be available fault level (AFL), augmented by an IBR stability objective. These concepts are explained in more detail below.
- **Level**: The level at which the standard would be set would be a value of a positive AFL, for some level of contingency redundancy, for a given amount of forecast generation, as determined by AEMO, at those nodes where the system strength standard applies.
- **Area:** The system strength standard will apply at specific "nodes" determined by AEMO, which would include areas of dense existing and forecast generation development, as well as other areas where a given level of system strength is necessary to maintain the security and effective operation of the power system.[34]
- **Administrator:** The settings of the network planning system strength standard are placed in the NER, which would include the requirement to maintain positive AFL and specify a IBR stability objective. These settings would be reviewed by the AEMC through rule changes as necessary. AEMO would have a key role in determining how the standard is implemented, through determining where the standard should apply and how much projected generation should be taken into account by TNSPs to meet the standard, set out in relevant AEMO guidelines.

Section 4.1.4 discusses each of these elements in more detail. In some ways, the most critical of the above components is the level - this will be a particular focus of the Commission over the coming months. We will be working closely with our technical consultants, AEMO and stakeholders to work out what this means in practice. It will also be a key area that we focus on in the public forum for feedback.

As noted above, the Commission intends to undertake extensive engagement with stakeholders to develop the next level of detail of this framework, as we move towards delivering a draft determination for the TransGrid rule change request (ERC0300).

4.1.1 Metrics for a system strength standard

This section sets out our key considerations and proposal for the metrics to be used as part of the network planning system strength standard. These metrics include the use of available fault level, complemented by an IBR stability criterion that is designed to support efficient connection and operation of generation.

Existing arrangements

34 In electrical engineering, a node is any point on a circuit where the terminals of two or more circuit elements meet. In circuit diagrams, connections are ideal wires with zero resistance, so a node may consist of the entire section of wire between elements, not just a single point. In a transmission network, a node could be a substation or switching station, and could include a substation to connect generation.

The *Managing power system fault levels* rule[35] (Fault levels rule) introduced the concept of a system strength service and defined it as "a service for the provision of a contribution to the three-phase fault level" at a given location in the transmission network.[36]

This definition provides a proxy metric, being fault level, against which system strength services can be measured to a limited extent - both in terms of the volume and location that it is being provided. However, this definition no longer fully describes all of the core aspects of system strength as a service that has evolved with increased experience and understanding of these phenomena.

Issues with the existing arrangements

There are two key issues with the use of fault level as a metric for system strength in the existing arrangements:

- Fault level is a proxy metric that may not accurately reflect all the key physical elements of system strength, which are set out in Chapter 2.
- Relying on fault level may preclude more efficient demand side options being explored, which could result in inefficient outcomes. This includes collective retuning, which is discussed more in Chapter 5.

Fault current remains a component of the overall concept of system strength, mainly in that it is needed for the proper function of protection equipment. However, the limitations described above mean that a new metric is necessary for more effective and efficient procurement of system strength into the future.

More detail on the above limitations can be found in Appendix A.

Key considerations for a system strength metric

When considering an appropriate metric for system strength, it is useful to split system strength into ‘active’ and ‘passive’ components:

- The **active** portion is the provision of voltage waveforms *and* the stability of inverters as they interact with these waveforms and each other. As such, it is both the active ‘supply’ of and active ‘demand’ for system strength.
- The **passive** portion is the general damping characteristics of the network, which is largely dependent on the impedance of the network.

It is the **active** portion of system strength that is not appropriately captured by defining or measuring system strength by reference to fault current alone. This is because fault current is effectively only a proxy measurement for impedance, and does not recognise the complex interactions that can exist between IBR generators and network impedances in an area.

Synchronous machines provide fault current, and are also active sources of voltage wave form stabilisation. As such, these sources of system strength are effectively captured by a metric that is based on fault current. However, there are other sources of system strength, which may be equally effective at stabilising the voltage waveform, but which may not be

35 AEMC, *Managing power system fault levels* Rule change, September 2017.

36 See definition of 'system strength service' in Chapter 10 of the NER.

effectively captured by a metric based on fault current (even though they may be equally effective and potentially more cost effective). These other potential sources of system strength include:

- Limiting the sources of inverter instabilities by ensuring appropriate individual and collective tuning of the control systems of IBR generation.
- Provision of stable voltage waveforms from virtual synchronous machines or grid forming inverters.

It follows that when defining an appropriate metric for the evolved framework (and hence the actual standard for system strength that TNSPs must meet), it is important to allow TNSPs to pursue any viable solution to system strength in the NEM. Put another way, the metric must be designed in a way that doesn't preclude TNSPs from utilising potential sources of system strength enabled by new technologies or techniques, especially where those new approaches may materially reduce costs for consumers.

Through consultation with AEMO and stakeholder engagement (through our technical working group), the Commission has found that no single metric for the standard will likely capture all system strength issues experienced in the NEM, nor fully enable all potential new technologies or techniques to address these issues.

We have therefore considered a number of different approaches to developing a new metric for system strength, with a starting point being the concept of "short circuit ratio" (SCR).[37] There are a number of variants in the SCR metric that may better reflect the various system strength phenomena described above. We describe SCR and its variations in more detail in Appendix A1. However, as described below, we consider that the most effective outcome will be to base the standard around the metric of "available fault level" accompanied by a set of requirements described as the "IBR stability criteria".

Recommended approach - Metric for the standard

Given the above, the Commission recommends the metric for the standard uses a combination of available fault current (AFL), accompanied by a criterion that the TNSP must maintain the stable operation of IBR.[38] These are described in more detail below.

Available fault level

We consider that this approach provides the most accurate representation of the efficient level of system strength, in that it describes the reduction in the probability that system strength constraints occur on existing or forecast connections, with the resultant benefits that this brings for consumers - that is, it describes the effective hosting capacity of the power system to operate stably with large penetrations of grid following IBR generation. It also provides an indication of the balance of system strength 'supply and demand'.

37 SCR is the ratio of fault current (MVA) at a particular location to the IBR capacity (MW) that needs to be supported at and around that location. In its simplest form, this could be the ratio of fault current to the nameplate capacity of a plant at its connection point. Typically, an SCR of three is regarded to indicate that there is enough system strength for the plant to operate stably.

38 AFL is an SCR and fault level based metric that provides a proxy measure for system strength, described in terms of the balance of supply and demand for the service. AFL measures system strength through the proportion of supplied fault level to demand for system strength from IBR generation, based on the minimum SCR capability of the IBR generation.

AEMO already uses AFL as the basis of its analysis to determine minimum fault level requirements under the existing minimum system strength framework. The Commission is proposing a modified and augmented AFL metric for the standard that more comprehensively captures the current and forecast demand of generation. The modified AFL metric would be comparable to an 'equivalent SCR' based metric in the way that it is applied.

The key strengths of using an AFL metric, augmented by an IBR stability criteria (described below), as the measure for the standard are that it is:

- comprehensive - using both of these together, the standard will recognise both the active and passive components of system strength which would allow TNSPs to address all types of system strength issues pursue all available solutions
- simple system strength provision - AFL is simple to calculate and forecast, and so is well suited to facilitating proactive system strength provision through a planning standard. TNSPs and AEMO are already familiar with the use of AFL as a system strength metric
- flexible to apply - both the AFL metric and the IBR stability criteria can be universally applied across the NEM, avoiding the need for determining different targets in different areas of the NEM every time the development of the power system changes or diverges from what is expected.

There are two key issues of an AFL based metric that should be taken into account:

- it is a conservative indication of system strength and
- may not capture all system strength issues (such as the active interactions between inverter control systems that do not relate to fault current).

IBR stability criteria

The Commission is therefore proposing the AFL metric described above should be accompanied by an additional "IBR stability criteria", such that the entire evolved description of the components of system strength (as set out in Chapter 2) is effectively captured in the evolved framework. Under this IBR stability criteria, the TNSP would face a general objective to ensure that the new generation forecast by AEMO can connect and operate stably.

In practice, we consider the stability criteria would:

- require TNSPs to ensure that all IBR accounted for under the standard (as determined by AEMO through its own forecasting and planning processes) is able to connect and operate stably,
- be set out in the NER, alongside the requirement to maintain a positive AFL to meet the planning standard, and
- be supported by an explicit description of what 'stable operation' entails, either set out in the NER or in an AEMO guideline, as appropriate.

This criterion would augment the AFL metric to allow the standard to capture all of the active components of system strength, and therefore would allow TNSPs to effectively consider all available options to address all of these components. For example, the IBR stability criteria would enable this by providing a trigger for TNSPs to preempt and solve inverter based instabilities that may occur, even in circumstances where passive system strength in the power system is relatively high (as provided by maintaining a positive AFL).[39] The IBR stability criteria would also allow the TNSP to meet the standard, when it can be proved that IBR can operate stably even when AFL is negative.

The criteria would therefore allow TNSPs to enable the stable operation of IBR through solutions that do not provide more fault current, such as collective generator retuning or grid forming inverters. The AFL metric and IBR stability criteria would be linked such that meeting the IBR stability criteria would result in the AFL being adjusted to be positive, such that the standard would be met in its entirety once effective provision of system strength, through any means, has been provided by the TNSP.

Appendix B sets out this proposal further, including an exploration of what AFL is as a metric under this proposal, its limitations, the supporting IBR criterion, and the other potential criteria that could be used for system strength.

4.1.2 The level of system strength required by the standard

This section sets out our key considerations and proposal for the level of the network planning system strength standard, which is AFL greater than zero.

Existing arrangements

Under the existing framework, a TNSP is only required to meet 'gaps' in the minimum levels of system strength, once a shortfall is declared by AEMO. The minimum level of system strength is the minimum fault level required to:[40]

- meet voltage step change limits
- support generator ride-through capabilities
- enable correct protection system operation.

In effect, this means that TNSPs are only required to procure sufficient system strength to meet the shortfall declared by AEMO. This means they maintain the security of the system, rather than to facilitate the efficient level of system strength in the network.

A system strength shortfall only occurs when projected 'available' system strength, in terms of AFL, drops below minimum levels. Available fault levels includes that provided by 'typical dispatch' patterns of synchronous generators; that is, the level of system strength that can be expected to be provided as a "free" byproduct of the dispatch of synchronous generators. AEMO is required to specify the size of the expected shortfall when it is declared.

Issues with the existing arrangements

One of the key issues of the existing framework is that forecasting system strength shortfalls against the minimum level, to a high degree of accuracy, is highly complex due to the modelling involved. Lack of extra system strength above minimum levels for system security and limited foresight as to when shortfalls will occur have, in some instances, resulted in shortfalls being declared quite late. In some instances, the shortfall had already occurred

39 This reflects the fact that inverter driven instability may still occur in circumstances when fault levels are relatively high.

40 AEMO, System strength requirement methodology, 2018, pp. 16-17

with the resulting constraints already binding. This has resulted in "reactionary", or delayed remediation actions, resulting in significant market intervention by AEMO through directions.[41]

The Commission understands that this issue generally arises due to the difficulty of taking into account all the variables that determine when a shortfall in AFL may occur, given the complex range of potential physical and financial outcomes in the power system. Specifically, forecasting expected typical dispatch patterns of synchronous generators, and on that basis then determining whether a system strength gap will arise, requires complex modelling and scenario analysis. These forecasts become more computationally intensive and less reliable, the further ahead AEMO attempts to forecast.

The Commission is exploring with AEMO as to how this issue around modelling complexity may be improved in any evolved framework. However, it remains the case that trying to forecast a highly specific, shortfall-based outcome is a difficult task, especially given the increased uncertainty about expected dispatch patterns of future synchronous generation.

Key considerations for the level of the standard

The Commission views the coordinated model would provide an appropriate basis for provision of an efficient level of system strength by TNSPs, which may include that required for system security, constraint alleviation, hosting capacity and power system resilience.

There are a number of key considerations relevant to the level at which the network planning standard for system strength should be set. Some of these considerations include:

- *What is the total amount of system strength to be procured?* The Commission expects this would be the amount of system strength sufficient to achieve a net beneficial outcome, including providing system strength sufficient to meet minimum levels, alleviate constraints and facilitate the connection and operation of inverter-based plant, where this is efficient. In practice, this amount would reflect the expected volumes of IBR generation that are forecast to connect, as per AEMO's forecast in the integrated planning process.
- *What operational conditions should be considered in setting the standard and hence how the standard should be met?* That is, to what extent should the standard be set by reference to particular operational scenarios, such as with respect to unexpected events and outage conditions (as opposed to normal operating conditions)?
- *Should extra system strength be provided for resilience?* Whether the efficient level should take into account levels of system strength that would provide power system resilience; that is, to enhance the power system's capability to resist cascading failure and extensive load shedding for a non-credible contingency. Such an allowance will inherently be provided due the proactive nature of the network coordinated model.

These considerations are discussed in more detail in Appendix A2.

Recommended approach - Level of the Standard

41 AEMO, *South Australia Electricity Report,* November 2019, pp. 5-6

The Commission recommends that the level of the standard be set at maintaining a positive AFL, or an AFL greater than zero, for some level of contingency redundancy.[42] The exact operational conditions for which the standard applies will be determined as part of the TransGrid rule change. Maintaining a positive AFL would mean that TNSPs would supply a level of system strength that allows all generation (that is assumed to be connected under the standard) to have high confidence they would not face congestion due to system strength limits.[43]

TNSPs would, as part of their requirement to meet the standard, take into account the forecast amount of generation that is expected to connect in an area, as determined by AEMO through its forecasting processes.[44] These considerations would then inform the "amount" of system strength that is then actually procured by the TNSP, being the amount needed to meet the standard.

In practice, this would result in a deterministic standard (rather than a probabilistic standard, for example), which would apply at nodes determined by AEMO, as discussed in proceeding section 4.1.3, noting that the IBR stability criteria would also be relevant to how the TNSP meets the standard in practice.

The key strengths of setting the level of the standard as being AFL greater than zero, for select operating conditions, are as follows:

- Facilitating proactive investment: Maintaining positive AFL to a deterministic level sets a simple target that triggers the need for TNSP investment, to provide needed volumes of system strength before significant issues related to any lack of system strength arise on the power system.
- More efficient than current arrangements: TNSPs could take advantage of economies of scope and scale to supply volumes of system strength needed to enable hosting capacity, which would otherwise be provided incrementally and inefficiently by individual generators as they connect.
- Flexible as the power system changes over time: The underlying amount of generation to be supported by the standard would be adjusted on a regular basis, as forecast assumptions change and real IBR investment occurs.

Appendix B sets out in more detail the level that the standard should be set at. This includes how much system strength the standard provides for, maintaining positive AFL as the efficient level of system strength, the amount of generation supported by the standard, how supply would change over time, and settings for a deterministic standard.

42 Clause 4.3.1 of the NER sets out AEMO's responsibilities for maintaining power system security, and the factors they need to consider in setting the technical envelope. One of these factors is keeping the power system at a level of N - 1 secure. Therefore, the Commission considers that N-1 conditions may be a good starting point on which to develop the standard. However, the efficient level of system strength provided by the standard may be lower, or may be different in different areas of the NEM, where and will be further examined through the TransGrid rule change.

43 Note, this would not preclude generators facing constraints due to other system limits, like thermal limits, which are not addressed through this mechanism.

44 This reflects the concepts, as described in Chapter 2, that grid following IBR generation "demands" system strength services, and will therefore tend to reduce the value of AFL, for each new connection.

4.1.3 Areas of the NEM where the standard will apply

This section sets out our key considerations and proposal for the areas of the NEM where the system strength planning standard will apply, which is for a nodal approach to be used, similar to that of the existing arrangements.

Existing arrangements

Under the existing system strength framework, AEMO determines the three-phase fault level nodes as the location where system strength is to be measured and sets these out in the system strength requirements methodology. These nodes are specific locations on the power systems, such as:[45]

- load centres
- synchronous generation centres
- areas with high levels of existing IBR generation or connection interest
- remote areas of the power system.

AEMO specifies the minimum fault level and provides a measure of AFL at these nodes. Where this AFL is forecast to be less than the minimum fault level needed at a node, AEMO declares a system strength shortfall and the relevant TNSP addresses the shortfall.

Issues with the existing arrangements

AEMO does not currently declare nodes based on long-term projections of generation development, as the current minimum system strength framework does not require it to consider the long term needs for system strength to facilitate the connection of future generation. However, long-term outlooks on areas that may host a large volume of particular types of generation are necessary for proactive planning by TNSPs to occur under a network coordinated model for system strength.

Furthermore, the AFL at system strength nodes is not published and is difficult to project sufficiently far out to provide effective locational signals to connecting generators. New entrants often have to wait for the results of their own final impact assessments, usually relatively late in their connection process, to determine whether there is in fact sufficient system strength available to support their connection and operation at their connection point; or to have sufficient information to influence their locational decision on the basis of system strength if they are a synchronous generator and so supplying system strength.

Key considerations for areas of the NEM where the standard will apply

Given the above, the Commission considers there is a need to clearly identify those areas of the power system where system strength will be provided in the future. This will provide clear locational signals to connecting generators - both IBR and synchronous - about where to locate, and help to drive the lowest cost long run outcomes for consumers.

The Commission also considers that the network planning standard for system strength should only apply to selected locations in the power system where it is forecast by AEMO,

45 AEMO, *System strength requirement methodology*, 2018, pp. 14-15

taking into account factors such as resource and network availability, that it may be a good location for new generation to connect. This is the approach currently taken by AEMO as part of its analysis for the ISP. In this way, the system strength standard would be designed to support efficient system strength levels, taking these forecasts into account.

A key challenge for the application of the system strength standard is delineating the system strength 'area of effect'; that is, the part of the power system in which the system strength provided to meet the standard would be said to have an effect. This would be the area in which the TNSP should plan for the standard to be met, and therefore where generators can have higher confidence that they will be able operate without being materially impacted by system strength limits.

Transparently describing the areas where the standard would apply is key to sending effective locational signals under the coordinated model. This would support generators to make efficient use of TNSP provision of system strength, and meet their connection obligations more easily (and therefore at low cost).

This would contrast with a more onerous connection process away from these areas, which may result in more complex connection processes and requirements to provide additional equipment to remediate the impact the generator has on local system strength. This is discussed further in Chapter 5, which recommends demand-side reforms for system strength.

There are two overarching options for determining where the standard applies.

1. A nodal approach is where the standard applies and is met at specified reference points, or system strength nodes.
2. A zonal approach is where boundaries are drawn around an area of the power system, geographical or otherwise, inside of which the standard is to be met universally.

The Commission considers that for the purposes of defining the areas where TNSPs will be obligated to meet the system standard, a nodal approach should be utilised. However, as discussed in Chapter 6, we are using a zonal approach for charging under the SSMR. While seemingly inconsistent, these approaches are in fact internally consistent; this is explained further in our description of the SSMR.

Appendix A3 also provides more explanation of the zonal vs nodal approach.

Recommended approach - Areas where the standard will apply

The Commission considers that a nodal approach for where the standard applies is most appropriate. As described above, the standard would apply at nodes where TNSP investment would be efficient, as determined by reference to AEMO's forecasts of expected IBR generation connection, and the TNSPs assessment of how best to meet the level of the standard. This would include identifying nodes near dense generation development, and where minimum levels of system strength must be maintained for network stability, such as near load centres. We outline the proposal for AEMO to identify nodes for the standard in section 4.1.3.

The key strengths of applying a nodal approach for the standard are:

- Simple to implement. A nodal approach is simpler to implement than a zonal approach as it avoids the need to draw administrative boundaries.
- Matches the metric. A nodal approach is more compatible with how AFL is calculated than a zonal approach. It is also familiar to AEMO and TNSPs as the approach currently used for the minimum framework.
- More granular locational signals than a zonal approach. The extent to which new connecting generation is supported by the TNSP's investment to meet the standard will be determined by their specific connection location as related to the node, as tested through the more straightforward preliminary impact assessment process.

Appendix B sets out this proposal further, including the application of a nodal approach for the standard and locational signals for connecting new generation.

4.1.4 The body responsible for setting and review of the standard

Clear roles and responsibilities will need to be allocated as part of the recommended network planning standard for system strength. That is, who would be responsible for setting, reviewing and modifying the standard. We propose is for it to be set out in the NER.

Key considerations

There are a number of options for who could be responsible for setting and administering the standard. These are outlined below.

- **AEMO**: AEMO has a planning oversight capability, and technical insights relating to the power system function of the NEM, and also has a role through the existing integrated planning frameworks, in determining optimal outcomes on the power system. However, we do not consider that AEMO would be the appropriate party to set and administer the standard. AEMO is better placed to have a fundamental role in determining *how, when and where the standard is applied,* which holds independent of which party administrates the standard.
- **Reliability Panel:** In the TransGrid rule change request (ERC03000), it is recommended that the Reliability Panel be the administrator of the standard. The Panel is a body that would be independent of AEMO and TNSP planning and procuring processes under the standard. The Panel can form an impartial view to determine the cost-benefit trade-offs that come with determining the settings of the standard.
- **AEMC**: Finally, the standard could be determined by the AEMC and set as a defined value in the NER, similar to other system standards like those that apply to voltage control. This would represent a transparent and relatively simple solution and would be consistent with other analogous arrangements. While it would also be relatively inflexible and may not respond as rapidly to the range of outcomes in the power system, it provides greater certainty and predictability for investors and TNSPs forecasting expenditure and making investments based on the standard.

Recommended approach - Setting and review of the system strength standard

The Commission considers that a NER based standard represents the preferable solution and that the AEMC would be able to review the standard and could receive rule change requests to make changes to the form or settings of the standard as required. AEMO would play a central role in the way the standard translates to actual outcomes on the system. This would occur through AEMO's central role in the integrated planning process. The Commission's view on AEMO's potential responsibilities in planning for the standard are set out in section 4.2.1.

The key strength of having the settings of the standard in the NER is transparency. Settings detailed in the NER must be clearly defined and publicly available, as do any AEMC review or rule change processes. NER-based standards can be inflexible and require comprehensive rule change processes to modify the settings. However, the benefit of a NER-based standard is increased certainty that the settings of the standard will not change without sufficient warning, which should help mitigate regulatory risk for IBR developers. It is also important to provide a level of certainty for TNSPs who will be making investment decisions based on the meeting the standard and forecasting their expenditure requirements to meet the standard ahead of five-year regulatory control periods.

AEMO and TNSPs would provide supporting information into the process as they both have the technical expertise to input into how the standard defined in the NER is best applied in practice. AEMO and TNSPs would collaborate at both the planning and procurement stages and so should not find the settings of the standard being fixed in the NER to be restrictive to deliver good power system outcomes as the NEM develops.

For example, we recommend that AEMO would develop and publish guidelines that set out the approach and details for how AEMO and TNSPs would plan for the standard over time, including how nodes are identified and how TNSPs should calculate AFL. This is consistent with the current system strength framework guidelines. Section 4.2 discusses the recommended responsibilities of TNSPs and AEMO in more detail.

Appendix B sets out this proposal further, including setting the standard in the NER, and requirements of the standard that sit outside the NER.

4.2 Planning for the system strength standard

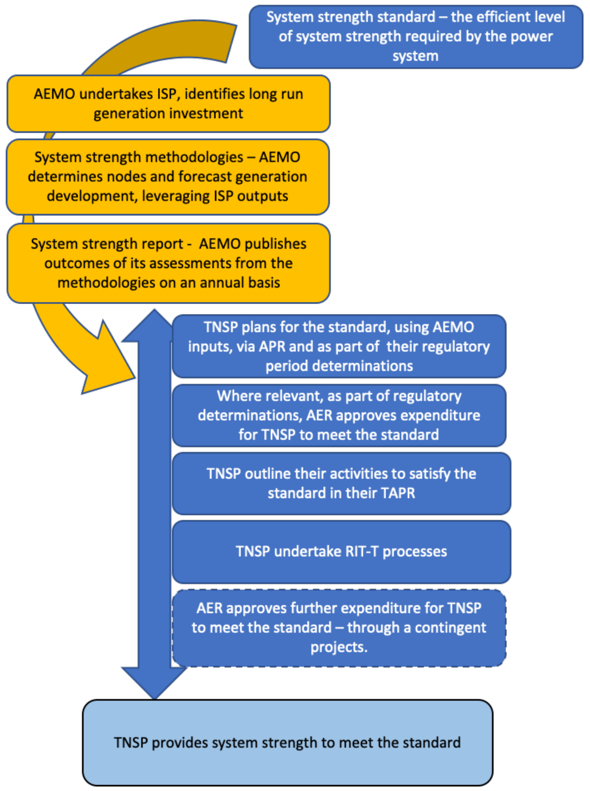
This section outlines the recommended roles and responsibilities of AEMO and TNSPs. As noted, we expect that AEMO and TNSPs would undertake a number of planning processes as part of the recommended evolved framework. These roles and responsibilities are split into two stages and include:

- Stage 1: A requirement for AEMO to:
  - undertake an assessment of where the standard would apply and how much new generation is expected to connect, and the implications of this for the standard, utilising information from the ISP. The Commission considers that AEMO must have a fundamental role in determining where, when and how much system strength should be provided in the power system. This is consistent with AEMO’s role as national transmission planner and responsibilities as power system operator, and will help to facilitate the proactive delivery of system strength at efficient levels to promote the long term interests of consumers.

- AEMO publishing the outcomes of its assessment in its existing annual system strength report. The requirements for stage 1 are outlined in more detail below.
- Stage 2: A requirement for TNSPs, utilising the existing network planning processes, to plan how it intends to meet the network planning standard for system strength as required by the NER, and where appropriate procure system strength services to meet the standard at the nodes and for the generation determined by AEMO in stage 1.

These planning processes are shown graphically below.

Figure 4.2: Planning processes for the recommended system strength standard



Source: AEMC

4.2.1 Stage 1: AEMO responsibilities for the standard

As noted, AEMO would play a key role and be responsible for determining the nodes based on its forecast of new generation that will connect to the system, and so the amount of system strength that the standard should result in. That is, AEMO works out the practical application for the system strength standard, being to identify the expected volumes of new generation connecting, and the resulting implications for system strength that the TNSP would be required to provide, through meeting its system strength obligations. We recommend that AEMO would, utilising the **information of the ISP** and information of the system's expected development, determine the:

- nodes where the standard will apply and
- develop an assessment of how much system strength needs to be provided at that node, based on current and forecast levels of generation seeking to connect to these locations.

AEMO is best placed to do this due to its system wide studies that it already undertakes as part of the ISP.

We also recommend that AEMO develop and publish **standing guidelines** that would set out what TNSPs should consider when undertaking their assessment of system strength at the relevant nodes, including the methodology for how AFL should be calculated and forecast by TNSPs.

AEMO would also continue to develop and publish its **system strength requirements methodology**, as it currently is required to do under the existing framework. However, as part of its evolved system strength requirements methodology, AEMO would detail how it would determine:

- where system strength needs are likely to increase and would benefit from scale efficient investment
- forecast generation in these areas using information from the ISP and information from TNSPs (e.g. connection enquiries and applications)
- minimum fault levels at all nodes for secure system operation.

Under the NER, AEMO currently publish an **annual system strength report**.[46] The Commission expects AEMO would continue to publish this annual system strength report, although rather than declaring shortfalls, it would publish the outcomes of its assessment of considerations outlined above.

We will consider what other elements of the existing system report should remain as part of the TransGrid rule change process.

4.2.2 Stage 2: Network planning processes to meet the standard

Existing arrangements

Under the existing arrangements, each TNSP (as the system strength service provider)[47] is required to make system strength services available to address system strength shortfalls in its region, as declared by AEMO.[48] AEMO enables these system strength services provided by TNSPs and third-party providers under specific circumstances, in order to maintain the power system in a secure operating state.

The TNSP considers how it has and will address any identified system strength shortfalls through the existing network planning and economic regulation process. Specifically, TNSPs

46 This was introduced under the Integrated System Planning Rules, which replaced the annual NTNDP with a two-yearly ISP.

47 In Victoria, the obligation to make system strength services available is placed on AEMO as the jurisdictional planning body.

48 NER Clause 5.20C.3.

must take into account in their annual panning review processes[49] the most recent ISP and system strength reports.[50]

TNSPs must publish a Transmission Annual Planning Report (TAPR) that includes information about the activities undertaken to satisfy its obligation to make system strength services available.[51] Where a TNSP has proposed network investment to achieve this, it must provide information in the next TAPR that sets out a range of information for their proposed network investment or non-network options and payments.[52]

A RIT-T is undertaken to identify net beneficial options[53] for a shortfall declared by AEMO. A TNSP does not currently have to apply the RIT-T for system strength services if:

- immediately prior to the notice being given, the TNSP had not been under an obligation to provide system strength services for that fault level node, and
- the service is required less than 18 months after the publication of the shortfall notice.[54]

A TNSP is also exempt from applying the RIT-T if the proposed expenditure is an inertia service payment or a system strength service payment.[55]

Issues with the existing arrangements

As discussed, the existing framework requires AEMO to declare a system strength shortfall prior to the TNSPs being required/able to take action.

Some TNSPs have suggested that it is difficult for them to account for the occurrence of shortfalls in their own planning processes in a timely manner.[56]

The Commission also understands that some TNSPs consider there is significant uncertainty whether the issues of proactively procuring system strength above minimum levels, and hence accounting for shortfalls considerations in planning processes, could be considered through the RIT-T framework, with flow on implications whether the AER will approve expenditure on system strength.

This uncertainty can arise in the absence of an identified shortfall and the NER not explicitly setting out a standard for the provision of system strength. Some TNSPs therefore argue they have not been able to address the system strength shortfalls proactively under the existing minimum system strength framework.[57]

49 The minimum planning period for the purposes of the annual planning review is 10 years for transmission networks. See NER Clause 5.12.1(c).

50 NER Clause 5.12.1(b)(3).

51 NER Clause 5.20C.3(f).

52 NER clause 5.20C(3)(g) and NER clause 5.20C(3)(h). Under clause 6A.6.6(c1), the TNSP must include the network support payments as operating expenditure in its revenue proposal.

53 For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) to the extent the identified need is for reliability corrective action or the provision of inertia network services required under clause 5.20B.4 or the provision of system strength services required under NER clause 5.20C.3." See NER Clause 5.15.A1(c).

54 NER Clause 5.16.3(a)(11)(i) and (ii).

55 NER Clause 5.16.3(a)(9).

56 Outcomes of the technical working group hosted by AEMC, 9 June.

57 AEMC, *Investigation into system strength frameworks in the NEM*, 26 March 2019, p. 10-12.

This was also supported by the rule change request submitted by TransGrid where it was stated that TNSPs often have limited time to procure the services before AEMO has to intervene in the market. This is due to the difficulties faced by AEMO in undertaking effective forecasting, which has resulted in declarations of system strength (and inertia) shortfall/s when they already exist, rather than at least five years out as envisaged in the framework.

Recommended network planning arrangements for system strength framework

TNSPs would have an obligation to meet the system strength standard in the NER. This involves proactively determining and providing the amount of system strength required to meet the standard at the identified nodes. In order to meet that obligation, we have recommended that the evolved framework rely upon the existing network planning and economic regulation processes. This reduces the need to introduce additional complexity and allows for timely implementation of any new recommended arrangements.

The recommended network planning arrangements under the evolved framework would include the following components.

TNSP assessment

TNSPs would need to calculate and forecast expected AFLs, to determine if the system strength standard would be met at the relevant nodes and for the volume of forecast generation that is expected to connect at the node, as identified by AEMO. TNSPs would subsequently set out in their TAPRs the system strength requirements for the relevant areas of their network and the possible options, including both network and non-network solutions.

TNSP reporting

TNSPs would take into account for their TAPR, AEMO's assessments in relation to system strength and other requirements, such as the ISP. As noted above, it is expected that the ISP and AEMO's annual system strength report will inform TNSPs, at a minimum, about the:

- system strength planning nodes where the standard would apply
- existing and committed generation around these nodes
- forecast retirement of generation, and
- minimum fault level requirements at all nodes.

Currently, TNSPs' TAPRs must include information about the activities undertaken to satisfy their obligation to make system strength services available. It is recommended that these information requirements and those outlined above and under clause 5.20C(3)(g) and (h) of the NER would also remain.

As part of the TAPR guidelines, TNSPs would need to include the following with respect to system strength in their TAPRs:

- the indicative parts of the network around identified system strength nodes that would likely be good areas for generation that demands system strength to connect, and those areas where it would be good for generation that supply system strength to connect
- the assumptions around how much generation it can expect to support for these areas

- projected available fault levels at each node
- committed generator development scenarios specifying the size and connection arrangements of committed future generators
- details of any committed system strength solutions.

This information will assist connecting generators to gain a better understanding of where system strength is likely to be available (or not avaliable) in a consistent manner. Some of the recommended information inputs are already a requirement for TNSPs, however it is expected that the information provided in the TAPR will be a greater level of detail. This is not considered to be an onerous task, with most TNSPs already providing this type of information to the market voluntarily.

TNSP expenditure

TNSPs would follow the existing regulatory investment test processes. We are also recommending that some form of the existing RIT-T exemptions remain. As part of the TransGrid rule change, we will also consider whether any refinements are needed to AER supporting guidelines, general requirements for contingent projects and the existing cost pass through triggers under Chapter 6A of the NER.[58]

4.3 TNSP procurement of solutions to meet the system strength standard

There are numerous possible procurement options that a TNSP may consider in order to meet its obligations under the recommended system strength planning standard. This includes consideration of network and non-network options. This section sets outs out these options including AEMO's role and considerations of economies of scope.

4.3.1 TNSP potential procurement options

In planning for the standard TNSPs will need to consider both network and non-network solutions to provide the required system strength level under the existing planning and regulatory framework. A range of solutions exist for system strength including:

- contracting with existing synchronous generators (or new) condensers
- building synchronous condensers
- transmission line augmentation
- retuning existing IBR generation
- procuring or contracting with grid forming services.

As noted, the metric and form of the standard itself must be carefully considered in order to avoid preventing TNSPs from pursuing all potential system strength solutions, such as collective retuning or the use of grid forming IBR. Retuning individual plant or groups of plant

58 Currently, a fault level shortfall event is considered a cost pass through event for a transmission business revenue determination. See NER Clause 6A.7.3(a1)(7).

or installing grid forming inverters to act as virtual synchronous machines could provide a very cost-efficient solution to maintain voltage stability in certain circumstances.

Another key issue relevant to TNSP procurement is the volume of system strength that TNSPs must actively procure, and the extent to which existing dispatch of synchronous generation can be assumed to provide some of this system strength "for free". This is currently accounted for through the consideration of 'typical dispatch patterns'. This issue, and its implications for TNSP procurement, are described in further detail below.

Consideration of typical dispatch patterns

Existing arrangements

Currently under the NER, AEMO's forecasts of expected system strength shortfalls are based on the typical patterns of dispatch generation in central dispatch, based on the generation mix that exists at teh current time.[59] As described in the previous Chapter, this process effectively assumes a given pattern of synchronous generation is dispatched, which provides a baseline of available system strength, effectively as a free byproduct of its output. Forecasts of typical dispatch patterns are used by AEMO in the existing arrangements to account for system strength provided through natural commitment of synchronous generators in the energy market, and therefore to assess any shortfalls against minimum requirements.

Issues with the existing arrangements

The dispatch patterns of all generation in the NEM is already a complex function of multiple physical and economic factors, and is likely to become increasingly uncertain as the transition accelerates. This means assessing typical dispatch patterns will become increasingly difficult to accurately forecast and therefore account for in AFL analysis. This could materially undermine the ability of TNSPs to forecast system strength needs of the power system in a way that clearly identifies when and how much investment is required.

Recommended approach

A key question to be considered in the design of the evolved system strength framework is whether these typical dispatch patterns should be considered as an input when TNSPs are considering how best to meet the network planning standard for system strength.

The Commission considers that under the evolved framework, TNSPs would not be required to consider expected ‘typical dispatch patterns’ of synchronous generators when assessing how to meet their system strength obligations under the standard.

Imposing an obligation on TNSPs to try and forecast these future patterns, and plan for the provision system strength around them, would likely impose an impractical obligation on TNSPs. Furthermore, it is not realistic to assume that typical dispatch patterns of existing synchronous generation will be relevant to supplying system strength to all areas of the system.[60] The Commission considers such an obligation would also increase the risk that

59 See definition of 'fault level shortfall' in Chapter 10 and Clause 5.20C.2.

60 For example, it would be impractical to rely on typical dispatch patterns of large synchronous units located in the Latrobe or Hunter valleys, when assessing system strength needs in a peripheral part of the power system like North West Victoria.

TNSPs do not procure system strength services sufficiently proactively, creating a risk of reactive investment in system strength, which would degrade the efficiency of the evolved supply side approach.

The Commission acknowledges that this approach may result in TNSPs having to actively procure and pay for larger volumes of system strength than they currently do. That is, TNSPs will not be able to assume the availability of the currently un-valued system strength that is provided as a by-product of synchronous generator self-commitment. As discussed further in Chapter 8, the particular supply side dynamics of system strength provision, particularly the localised nature of the service and potential for transient market power to be exercised by system strength providers, creates a risk that this could cause increased costs for customers.

Various measures may act to ameliorate these risks, such as allowing TNSPs adequate time to meet their obligations, as well as relying on the prospect of AEMO intervention as an incentive on generators to enter into contracts at an efficient price. Furthermore, in areas with a relatively liquid supply side of synchronous generators, any contracts with synchronous generators required to meet the system strength needs of the area may be lower cost, by virtue of the effects of competition and low enablement costs.

Section 4.4 discusses what potential options could be available to the TNSP if the only options available to it were inefficiently costly.

The recommended model would not value the system strength provision of generators as a byproduct of energy production, where it is above what TNSPs are required to provide to meet the standard itself.

4.3.2 The role of AEMO in the evolved system strength procurement framework

This section discusses the role AEMO may play in both an investment and operational timeframe.

Investment timeframe

AEMO's responsibility to identify nodes and forecast generation through its forecasting functions provides it with a mechanism to enable sufficient system strength levels to be provided to maintain the secure operation of the power system. This role will be critical in determining the efficient amount of system strength to occur in different areas of the NEM. This will help to deliver needed services and necessary investments in the required assets to maintain sufficient system strength in appropriate timeframes.

In developing the evolved framework, the Commission also considered whether some form of "procurer of last resort" function for AEMO - similar to an amended NSCAS type mechanism – would be necessary on an enduring basis, or assist in the delivery of needed volumes of system strength. However, we consider such a mechanism is unlikely to be required on an enduring basis for the purposes of providing system strength in investment timeframes. This is primarily on the basis that the purposefully proactive nature of the evolved framework, and AEMO's significant role in the planning timeframes to determine system strength needs, means that gaps or shortfalls in the provision of system strength should not occur. As such, a procurer of last resort mechanism should not be needed on an enduring basis. Something may be needed in the transition, and this is discussed further in Chapter 8.

Furthermore, we also considered that if such a role was embedded in the enduring framework, it may have a number of distortionary impacts, such as:

- weakening the incentives on TNSPs to procure the amount of system strength required by the standard
- reducing competition for non-network solutions, where some providers may prefer AEMO being the procurer over the TNSP – as has been seen with some NSCAS procurement processes.

Operational timeframe

The unit commitment for security (UCS) that has been recommended for implementation by the ESB, would be used in the pre-dispatch timeframe to check the right complement of resources will be available to ensure system strength will be maintained, and, where this is not the case, to optimise the commitment of additional resources held under contract.[61]

The ESB has stated in its recent consultation paper that the UCS would complement the establishment of a synchronous services procurement mechanism (covering system strength and inertia). The ESB is also considering approaches for voluntary, financial ahead markets to procure and/or trade system services (including those that may not have a real-time market), possibly co-optimised with energy. The Commission is continuing to work as part of the ESB on these matters to make sure that there is the right mix of essential system services in operational timeframes.

Some system strength assets or services procured by TNSPs will not require significant or ongoing operational consideration by AEMO. This is because we expect they will be "set and forget" type services (like retuned inverters) or assets that are left operating most of the time (like synchronous condensers). To the extent that outages of these assets need to be coordinated, the Commission considers that this can be efficiently managed through incentives provided to the TNSP by the existing STPIS arrangements.

Enabling and scheduling investment timeframe solutions in the operational timeframe

Additionally, as TNSPs will have the obligation to provide system strength services under the evolved framework. TNSPs will have scope to do this through utilising network or non-network solutions. This means TNSPs may build assets - such as a synchronous condenser - or contract with synchronous services providers – such as synchronous generators.

In either case, these solutions would need to be coordinated by AEMO, and explicitly accounted for in the dispatch process. This is necessary as both solutions will have implications for how AEMO operates the system, specifically what actions it needs to take to maintain a secure operating state. In some cases, the dispatch of these solutions may also have implications for how the wholesale spot price is determined.

61 ESB, *Post 2025 market design consultation paper, Scheduling and ahead markets MDI,* September 2020.

On this basis, we expect that AEMO will effectively coordinate and control (in some form) these solutions in the operational timeframe. This is in keeping with current arrangements, where AEMO gives instructions as to the operation of system strength services procured by the TNSP to meet its obligations.[62]

We will give further considerations as to the details of how this operational control will occur, as we progress to making a draft determination of the TransGrid rule change request as well as through the ESB's Post 2025 market reform project.

4.3.3 Economies of scope

TNSPs are obligated to provide multiple system services, some of which can be provided by the same assets. Being able to build a single asset to meet its obligation to provide these multiple services allows a TNSP to realise economies of scope across multiple system services.

The current arrangements do not facilitate the co-ordination and co-optimisation of system strength with these other services to realise efficient economies of scope across the provision of these various services.[63] The Commission considers that the evolved system strength framework would better enable the TNSP to realise economies of scope when providing other system services by utilising the existing planning and regulatory processes.

4.4 Pricing solutions for the system strength standard

The economic regulatory frameworks will ultimately determine cost of system strength services. This involves the price paid by TNSPs when procuring the services, and then the revenue TNSPs can recover from consumers allowed by the AER. This section explores the first point, including how the structure of the supply side and the time available to assess all options will enable TNSPs to procure the lowest cost or net beneficial solution. The second point is explored in section 4.5.

4.4.1 Structural issues regarding the system strength supply side

TNSPs may contract with existing synchronous generating units to meet their system strength obligations under the recommended standard as discussed in section 4.3. The procurement by TNSPs of non-network solutions is an established practice already utilised by TNSPs. However, as described above, and further in Chapter 8, the physical characteristics of system strength and structural elements of the system strength supply side, may create risks that the prices charged for these non-network solutions are inefficient.

TNSPs can exercise some countervailing power to manage these issues as the single, monopsony buyer of non-network services. However, there are some limitations on this power. For example, sellers of non-network solutions have some visibility of the cost of a network asset alternative, which means they can price non-network solution up to this cost

62 NER Clause 5.20C.4(d).

63 Economies of scope refers to the ability to realise efficiencies by co-optimising system strength solutions with other system security service solutions and services.

and thus extract some portion of potential consumer surplus. Furthermore, a relatively rapid introduction of an obligation to provide system strength may also reduce the ability of TNSPs to exercise their countervailing power.

As discussed later in Chapter 8, these kinds of issues can be resolved, or at least partly ameliorated, by providing sufficient lead time to TNSP to meet its obligations. In addition, we could consider what guidance or regulation could be put around what charge generators supplying system strength get paid (similar to the way that generators demand system strength have to pay a charge, as described in Chapter 6).

The Commission considers that the inherent proactivity of the supply side model that has been recommended should provide sufficient time for TNSPs and should significantly reduce the risk of this situation from arising. TNSPs should have adequate opportunity to effectively plan for and procure the highest net benefit solution to meet the standard. As noted, we have given particular consideration to this issue as it relates to the period of transition to the new framework, as this is the period where transient market power creates the greatest risks for inefficient prices.

Mechanisms to manage sudden, critical shortfalls

Despite proactive planning, there is always the possibility that errors in forecasting - or unexpected events on the power system - could result in a sudden, critical shortfall in need for system strength. There is a potential for transient market power becoming an issue in certain areas of the network if TNSPs find themselves in a situation where they are obligated to procure system strength from a small number of synchronous generators on an urgent basis.

The Commission considers that the TNSP, through its annual planning and regulatory investment test, have the ability to assess both network and non-network solutions for a range of services, including system strength. Credible options are then identified and outlined in the annual planning reports and relevant RIT-T to the market and there is regulatory oversight by the AER.

In the circumstances of an emergency situation, we consider it is appropriate for AEMO to use the existing tools for interventions and / or constraints to address any system strength gap, if this were to present a system security risk.

- For intermittent or sudden gaps, AEMO could intervene and direct synchronous generation to increase the 'supply' of system strength.
- For gaps with more lead time or that will exist for a short period, AEMO could reduce the 'demand' by constraining inverter-based generation and / or instructing them to disconnect their inverters.

Relying on the directions power would place a limit on the total cost of sourcing these services from generators that hold market power - currently, compensation for directed participants is paid based on the 90-percentile price for the relevant region over the preceding 12 months.

We consider there is a relatively low risk that AEMO will need to undertake these kinds of actions in future. A sufficiently proactive framework, supported by AEMO's planning function, means that these kinds of events should not occur frequently.

As indicated, we consider that any form of formalised AEMO procurement mechanism is unlikely to be needed on the basis of providing a "backstop" solution to manage unexpected shortfalls in system strength on an enduring basis (but may be considered in the transition).

4.5 Paying for the system strength standard

Currently, the AER determines the maximum amount of revenue TNSPs can recover from consumers over a defined regulatory control period for 'prescribed transmission services'. These include services required under the rules and relevant jurisdictional legislation. Prescribed transmission services are those that are regulated by the AER – and currently, all of these are paid for by consumers through TUOS charges.

Under the evolved system strength framework, TNSPs would plan the network to meet the system strength network standard. TNSPs will incur costs in doing so, as they undertake network build or procure non-network solutions.

Given that TNSPs would utilise the existing network planning and economic regulatory framework, the provision of system strength solutions by the TNSPs would be subject to the same regulatory oversight as other prescribed transmission services by the AER, and these services will be paid for by consumers through TUOS charges.

However, the Commission considers that the costs of providing system strength services should be shared between consumers and generators. This mechanism will better coordinate the supply and demand of system strength. We are therefore proposing a charging mechanism, which will allocate some of the costs of system strength to generators - this proposal is set out in Chapter 6. In addition, to this, lower supply of system strength will be required due to the demand side generator performance requirements, as set out in Chapter 5.

5 DEMAND SIDE: GENERATOR OBLIGATIONS

BOX 4: SUMMARY OF KEY FINDINGS

Experience from connecting grid following inverter based resources (IBR) in the NEM has shown the need to continue to consider whether the access standards for generators are still fit for purpose, to support the security of the power system and reduce the demand for system strength services from these generators.

Experience gathered through the implementation and use of the system strength frameworks over the last three years has demonstrated the potential need for new access standards. These will support system security and reduce the overall demand for system strength services from these generating systems.

Therefore, we are proposing two changes to the generator access standards, which introduce two new standards for system strength for generators. These standards would require generators to be capable of the following:

1. Short circuit ratio — having a general capability to be able to operate stably to a given level of system strength, as measured by a short circuit ratio (SCR) capability.
2. Voltage phase shift — having minimum (achievable by type 3 wind turbines) and automatic (higher and achievable by other IBR) access standards for maintaining continuous uninterrupted operation following a large shift in the phase of the voltage at the generating system. This new standard would not apply to synchronous generating systems and would rely on the generator and network service providers to negotiate an appropriate level for the connecting generating system.

In each case, the Commission considers that the inclusion of these two additional access standards is expected to:

- enhance security of the power system, by delivering greater certainty that generation that demand system strength will remain stable and connected to the power system under lower system strength conditions
- lower demand for system strength services, therefore reducing the mitigation costs and increasing network hosting capability
- increase flexibility for future re-tuning of generator control systems as the penetration of generation increases. This should enable lower cost, demand based solutions to be explored and utilised, to help deliver efficient utilisation of the available network and reduce costs for consumers

We will continue to consider two additional changes over the coming months:

- the specific values to be associated with the SCR or phase shift access standards.

- the arrangements for damping, including giving further consideration whether the existing requirements for connecting generators to provide damping of power system oscillations are appropriate for managing inverter-driven stability.

The Commission will continue considering these changes, having regard to submissions received during this review as well as the issues raised in the *Efficient management of system strength on the power system* rule change proposal (ERC0300), and will consult on a developed proposal in the draft determination for that rule change.

Also, the Commission considers there are a number of areas where further analysis is warranted. In particular, we consider there may be benefits associated with development of a formal framework in the Rules for how collective generator re-tuning should occur. There may also be merit in exploring how effectively the existing generator access standards consider issues specific to IBR, which should occur through the upcoming review of the generator technical performance standards.

The evolved framework sees the supply side approach complemented by new system strength access standards (a form of mandatory technical limit) on for new connecting generators to manage the "demand" for system strength services. As set out in Chapter 2, grid following IBR create "demand" for system strength, since they require a stable voltage waveform to operate effectively. The amount of system strength demanded by these resources depends on several factors, particularly the capabilities of the inverter equipment used. Therefore, system strength services may not be efficiently utilised if their demand is not adequately managed through imposing mandatory technical capabilities through the generator access standards on IRB to use inverter equipment with at least a given level of capability.

Note that in this chapter the term IBR more specifically refers to IBR generation that have a nameplate rating greater than 5 MW and are registered as generating systems. It does not refer to other forms of IBR such as DER and NSP voltage control equipment.

This Chapter sets out the:

- background on the existing 'do no harm' arrangements
- recommended additional access standards to manage system strength demand
- potential changes to the arrangements for damping of power system oscillations
- other potential future changes for further consideration.

5.1 Background on the existing 'do no harm' arrangements

The current 'do no harm' arrangements already creates some incentives for the connecting generator to install equipment that will have a low impact on the stability of the existing network.

The "do no harm" arrangements do this by requiring connection applicants to undertake remediation (or have the network service provider undertake system strength connection works) if the generator's connection will have an adverse system strength impact.[64]

However, as the Commission acknowledged in the earlier Discussion paper for this review, the current 'do no harm' arrangements need to evolve, since it may act as a potential deterrent for new entrants in the NEM. Stakeholders suggested these arrangements have impacted negatively on the generator connection process by imposing both time and cost delays, and so is potentially resulting in inefficient system strength provision. Additionally, while this was anticipated under such arrangements, the practical outworkings of new entrants building their own synchronous condensers has resulted in additional operational and modelling complexity for both the NSPs and AEMO.[65]

In addition to the system strength framework, the NER also set out the generator access standards.[66] All new generators with nameplate capacity greater than 5MW are required to connect in accordance with these access standards, by negotiating with the local (transmission or distribution) network service provider, to determine generator performance standards (GPS) that are specific to each generating system. These GPS must meet the requirements of the generator access standards.[67] These access standards include a wide range of requirements related to the secure operation and planning of the power system.[68] However, there are currently no generator access standards that specifically relate to system strength.

5.2 Additional access standards to manage system strength demand

The Commission recommends the introduction of new generator access standards that would relate specifically to system strength.[69] These new access standards relating to system strength would promote the NEO since they will support the security of the power system and help minimise the overall demand for system strength services, and therefore the total cost of providing these services.

These new access standards for system strength place obligations on newly connecting generators under the NER to have equipment with capabilities sufficient to allow them to perform to the set standard(s). The use of a system strength access standard should be a

64 Clause 5.3.4B of the NER.

65 TransGrid, submission to the discussion paper in March 2020.

66 Schedule 5.2 of the NER sets out the conditions for connection of generators, including the access standards in S5.2.5 and S5.2.6.

67 The access standards for connecting generators are described in Schedules 5.2.5 and 5.2.6 of the Rules. Most of these standards include a "minimum" and "automatic" level. When negotiating a connection to the relevant network under clause 5.3.4A, a connecting generator must propose a standard that is as close as practicable to the automatic access standard taking into account: the need to protect plant from damage, the power system conditions at the location of the proposed connection and the commercial and technical feasibility of complying with the automatic access standard with respect to the relevant technical requirement. Many of these standards, particularly those that relate to power system security, are "AEMO advisory matters", where the network service provider must take into account AEMO advice when deciding whether to accept or reject a proposed standard.

68 The AEMC amended the generator access standards and the framework for negotiating performance standards in the *Generator technical performance standards* rule, which was published on 27 September 2018 (ERC0222).

69 These are sometimes referred to as "generator performance standards", or GPS. However, the access standards refer to the standards that are defined in the NER, while the GPS refer to the actual technical performance requirements that are negotiated by each generator as part of establishing its individual connection agreement with the relevant NSP.

simple and effective change because it utilises the existing well-known and understood process for negotiating generator access standards. How the recommended system strength access arrangements are planned for, procured, priced and paid for is set out in Figure 5.1.

Figure 5.1: How the demand side is planned, procured, priced and paid for

1 PLAN	The requirements of the access standards are specified in the rules and the levels negotiated during the connection process.
2 PROCURE	The connecting generator procures equipment, including inverters, to meet the requirements agreed with the NSP during the connection process.
3 PRICE	The price is determined during the negotiations between the connecting generator and the equipment supplier.
4 PAY	The costs of meeting the access standards are met by the connecting generator.

Source: AEMC

The recommended new access standards for system strength include a new standard for maintaining operation down to a given level of SCR, and another related to phase shift withstand capability. These are described in the following two sections.

5.2.1 Short circuit ratio access standard

The Commission recommends that an additional requirement be included in the generator access standards in the NER to require new connecting generating systems to be capable of meeting all of their agreed performance standards at a specified short circuit ratio (SCR) level,[70] including to maintain continuous uninterrupted operation during disturbances and to remain stable during steady state operation. This is intended to reduce the demand for system strength services and therefore increase the benefits from the investments made by the TNSP through the system strength planning standard (discussed in Chapter 4 of this report).

This recommended SCR requirement would apply to generation that generally add to the demand for system strength and this would be reduced to the extent that it can operate at a low SCR. The recommended requirement would not apply to synchronous generating systems, as the connection of these systems would add to the supply of system strength, meaning that only the existing stability requirements in the access standards would apply to these generating systems.[71]

70 The performance that is negotiated with the network service provider, recorded in the connection agreement between the generator and network service provider, and registered with AEMO in accordance with clause 5.3.7(g)(1), clause 5.3.9(h) or established in accordance with rule 4.14.

71 The generator access standards in the rules are general technology neutral and apply equally to both synchronous and IBR generation. One exception are the requirements of S5.2.5.5 for generating system response to disturbances following contingencies where the requirements for synchronous and asynchronous generating systems are expressed different to reflect the characteristics of the technology.

Setting the level of the SCR standard

The level of the SCR requirement could potentially impact both the cost of connecting new generation and the cost-effectiveness of the measures undertaken by TNSPs to mitigate system strength impacts. This is because a tighter minimum SCR standard could increase the cost of connecting new IBR generation, by requiring higher capability inverters, which may in turn be more costly. Conversely, a looser standard could increase present and future mitigation costs of managing generation.

The recommended access standard for SCR would be a single standard, rather than having both an automatic and minimum access standard. This would be simpler as it removes the need for negotiation and would mean that:

- the connecting generator's equipment must be capable of meeting a given level of performance
- the network service provider cannot require that the connecting generator's equipment be capable of operating below the level specified in the SCR access standard.

Compliance with the recommended SCR standard

The recommended SCR access standard would be a requirement for an generating system that demand system strength to demonstrate its capability to operate effectively down to a nominated SCR. However, the actual tuning, or setting, of the generator will be done by reference to the prevailing conditions at the connection point. As such, this access standard forms an obligation on the physical capability of the generator's equipment, rather than an actual requirement for the physical tuning and behaviour of the generating system at its connection in the network during real time operation.

Compliance with this standard would be demonstrated in the absence of nearby generation using a single machine infinite bus model.[72] That is, the generator would be tested in a standardised environment to establish its capability, rather than the specific system conditions where it is connected, which will change over time as addition generation connects and the network is modified.

It is important to note that the recommended SCR requirement for a generating system would not:

- remove the generator's obligation to meet all other performance standards at its specific location
- mean the inverters should necessarily be tuned to the low SCR level specified in the access standard, rather they should instead be tuned to the specific requirements at the connection point, which may be a much higher SCR.

5.2.2 Voltage phase shift withstand access standard

The Commission understands that the large phase shifts of the voltage at the generator's connection point that can occur in the power system have caused some inverters to trip

72 A single machine infinite bus (SMIB) model is can be used to test or tune a single generating system in isolation from other generating systems or network effects.

following the switching of a nearby transmission element. This occurs if the inverter's control system fails to maintain synchronism with its terminal voltage and is more likely to occur in weak parts of the transmission network as the phase angle shifts would be larger and the low system strength following the switching of the element.[73]

Such phase shifts of the terminal voltage of a generating system occur when a network element, such as a transmission line, is switched out of service due to the redistribution of the power flows within the network.[74]

Large voltage shifts are more likely to be a problem in weaker networks. This is because the voltage phase shifts are generally larger, due to:

- the larger line impedances, and
- because inverter controls find it harder to track the terminal voltage, due to the stronger interaction between the inverters and the network.

The size of a given phase shift of the voltage at the generating system's connection point will depend on the:

- topology and impedances of the relevant part of the network
- distribution of load and generation within this part of the network
- element in the network what is switched.

Therefore, it is recommended that an additional requirement be included in the generator access standards to require new connecting generating systems to be able to maintain continuous uninterrupted operation for at least a given shift of the phase of the voltage at its connection point.[75]

Setting the level of the voltage phase shift standard

The level at which the voltage phase shift standard is set could potentially impact both:

- the performance required, and hence cost, of the inverters; and
- the need to limit network flows through constraints, to limit the size of the voltage phase shifts that could occur following a contingency event.

A tighter standard could increase the cost of connecting generation by requiring higher performing inverters, as well by reducing competition due to there being a smaller number of compliant inverter manufacturers. Conversely, a standard that is not as tight could increase present and future network constraints on the dispatch of generation within an area of the network, in order to reduce the maximum voltage phase shifts that could occur, and avoid large scale generator tripping.

73 We also understand that these issues have been resolved in certain cases by the manufacturer retuning their control systems to better track the phase of the voltage at the inverter terminals.

74 A similar shift in the phase of the voltage at the generating system can also occur when a transmission element is switched in, however, this is less likely to interrupt the operation of the generation as switching in a transmission would increase the system strength.

75 Continuous uninterrupted operation is defined in Chapter 10 of the Rules. It relates to the performance of generating systems during and following a disturbance or fault in the system.

Application of the standard for different generation technologies

Stakeholders at a technical working group meeting for this review indicated that the capability of different generating systems to meet this recommended standard may vary, depending on their technology, in particular synchronous generating units and type 3 wind turbines.

Synchronous generating units are prone to angular instability following a disturbance that results in the phase of the terminal voltage shifting. This can result in the generating unit losing synchronism with the network and disconnecting. In addition, the presence of the synchronous generating unit would itself limit the rate of change of the phase of the voltage. Therefore, some stakeholders suggested that it may not be appropriate to apply the recommended minimum voltage phase shift access standard to synchronous generating units, or at least a lower standard should apply.

In addition, the voltage phase angle withstand capability of type 3 and type 4 wind turbines are likely to be quite different. This is because type 3 wind turbines are doubly-fed induction generators and are more likely to have mechanical interactions following a large voltage phase shift, when compared to type 4 wind turbines that uses full inverters that result in greater decoupling between the electrical and mechanical systems. Therefore, imposing too arduous an access standard could make it difficult for type 3 turbines to comply, which would reduce competition for the overall supply of wind turbine.

Therefore, it is recommended that the access standard for voltage phase shift would:

- not apply to synchronous generating systems
- include a minimum access standard that is achievable by type 3 wind turbines
- include an automatic access standard that is higher and achievable by other IRB such as type 4 turbines, solar PV and battery storage
- rely on the generator and network service provider to negotiate an appropriate level for the connecting generating system.

An access standard of this form for managing voltage phase shifts would also provide the flexibility to accommodate generation connection in parts of the network where large phase shifts would only be expected following non-credible contingencies, at the same time as requiring higher performance in weaker parts of the network where larger phase shifts could be more common.

5.2.3 Further development of the recommended standard

We will continue to consider what the exact specification of the recommended minimum SCR and voltage phase shift requirement for the generator access standards should be. This will include setting efficient levels for this standard, and incorporate feedback from AEMO and market participants. We will also conduct a survey of a selection of relevant equipment manufacturers.

We will continue considering these changes for the recommended access standard, having regard to submissions received during this review as well as the issues raised in the Efficient management of system strength on the power system rule change proposal, and will consult on a developed proposal in the draft determination for that rule change.

5.3 Damping of power system oscillations - provision of additional damping

Damping is a characteristic of any potential oscillatory behaviour in a system. In the case of electrical power systems, oscillations can occur through the interactions between the network, the generators and their control systems, particularly following a disturbance. Some key elements of oscillatory behaviour include and oscillation that:

- decays slowly is referred to as lightly damped
- decays quickly is referred to as heavily damped
- grows is refers to as negatively damped.

Minimum levels of damping capability are required to mitigate the risks of equipment damage due to these oscillations, and provide margins against negative damping.

The level of damping of the power system depends on the characteristics of the power system components, the operating state and the setting of the associated control systems. Additional damping can be achieved by tuning the settings of generator control systems or by changing system operating conditions, usually with a constraint on network flows.

5.3.1 Definition of adequate damping in the Rules

The damping requirements in the generator access standards are specified in terms of 'adequately damped', which is defined in Chapter 10 of the Rules. These damping requirements relate to the power system oscillations associated with local modes and inter-area modes. The NER Chapter 10 definition is:

> In relation to a *control system*, when tested with a step change of a feedback input or corresponding reference, or otherwise observed, any oscillatory response at a *frequency* of:
>
> (a) 0.05 Hz or less, has a damping ratio of at least 0.4;
>
> (b) between 0.05 Hz and 0.6 Hz, has a halving time of 5 seconds or less (equivalent to a damping coefficient –0.14 nepers per second or less); and
>
> (c) 0.6 Hz or more, has a damping ratio of at least 0.05 in relation to a *minimum access standard* and a damping ratio of at least 0.1 otherwise.

Paragraph (c) of the definition applies to frequencies above 0.6 Hz, which has also been applied by default to inverter-driven stability.

The AEMC and AEMO are working together to consider whether these damping requirements are appropriate for inverter-driven stability, or whether an alternative specification of adequate damping should apply for the higher frequencies associated with inverter-driven stability, and whether these should be included in the NER definition.

5.3.2 Review of the existing requirements in the access standards

It is unclear at this stage whether the existing requirements in the access standards in clause S5.2.5.13 for connecting generators to provide damping for power system oscillations are adequate for damping inverter-based instabilities.

The existing access standards for connecting generation systems require the generating systems to have a power oscillation damping capability with sufficient flexibility to enable damping performance to be maximised.[76] For synchronous generating units this would be met using a power system stabiliser (PSS) with sufficient flexibility.[77] Power oscillations can occur when the inertia provided by synchronous generating units interact via the impedances of the associated transmission network with:

- local modes of oscillation between an individual generating unit and the remainder of the power system (normally between 0.7 to 2.0 Hz)[78]
- inter-area modes of oscillation between groups of generating units in different regions (normally between 0.4 to 0.7 Hz).

The PSS fitted on large synchronous generating units to dampen local modes can also be tuned to dampen any unwanted inter-area modes. Failure to dampen these modes can result in damage to generating equipment or limits on the power transfers across inter-connectors.

However, inverter-driven stability is quite different to the power oscillations contemplated by the existing damping requirements in the NER. This is because inverter-driven instabilities do not involve the inertia of synchronous generating units, but occur at much higher frequencies in the range of about 5 to 15 Hz, and involve interactions between the control systems of one or more IBR and the associated network impedances.

In addition, the various generation technologies from the different manufacturers are likely to have a diverse range of different control system configurations. This may mean it would be difficult to specify the control system characteristics that would be required in the generator access standards for the provision of damping .

Given the above, we are currently considering whether a new requirement should be placed on AEMO to develop guidelines for the damping requirements for generation systems. This would allow AEMO to update these requirements for new connecting generating systems as its experience with connecting new technology generation increases. AEMO would be required to use the Rules consultation procedures when developing and updating these guidelines to ensure that all stakeholders' views are considered, including equipment manufacturers and network service providers.

76 Schedule 5.2.5.13(b)(3)(ix) of the Rules for synchronous generating units and schedule 5.2.5.13(b)(4)(vii) for other generating systems.

77 Schedule 5.2.5.13(c) specifies the automatic access requirements for PSS flexibility.

78 The frequency of local and inter-area modes depends on the generation, network and power flows in the system. The ranges provided are taken from Kundur "Power System Stability and Control", McGraw Hill (1994), p. 817.

5.3.3 Further development of the recommended standard

The Commission is continuing to review the existing definition of 'adequately damped' and the specification of the damping requirements in the generator access standards. This includes collaborating with AEMO, engaging with market participants, and undertaking a survey of a selection of relevant IBR equipment manufacturers.

We will continue considering these changes, having regard to submissions received during this review as well as the issues raised in the *Efficient management of system strength on the power system* rule change proposal, and will consult on a developed proposal in the draft determination for that rule change.

5.4 Other potential future changes for further consideration

The Commission recognises there may be other additional measures (beyond damping requirements) to effectively and efficiently manage the demand for system strength in the power system as the power system continues to evolve. Further analysis is required to best understand the potential benefits, costs and inter linkages of these measures. As such, the Commission welcomes further dialogue with industry over the measures described below.

5.4.1 Collective re-tuning of generating system controls to reduce the need for system strength

As discussed in Chapter 2, the demand for system strength services depends on the tuning of the IBR control systems. Therefore, re-tuning of inverter controls can in some instances be an effective mechanism to manage inverter-driven instability.

The effectiveness of re-tuning inverter controls depends on the given circumstances. For example, there would be limited benefits from re-tuning inverter control systems where all the IBR in an area are of good quality and already well tuned to match the system conditions. However, in the presence of one or more low performing incumbent IBRs in a weak part of the network can dramatically increase the demand for system strength services. In such cases re-tuning of the incumbent IBRs is likely to reduce the demand for system strength and increase the hosting capability of the network. While re-tuning may be effective in many circumstances, it may not be known in advance the extent of the potential benefits that re-tuning may be able to deliver.

Many stakeholders are concerned about managing the demand for system strength IBR using re-tuning. These concerns include the potential for:

- the incumbent generators to incur costs and lost revenue should re-tuning of their generating system be required
- re-tuning of the inverters to require unrelated generator performance standards to be reopened.

Schedule 5.2.2 of the Rules enables a new control or protection system setting to be applied where a setting of a generating unit's control system or protection system needs to change to comply with a relevant performance standard. However, we consider that the specific NER mechanism for retuning of generators should be considered in further detail, with a view to determining whether new provisions in the NER are required to provide greater guidance and clarity as to how retuning might be effectively utilised.

At this stage, we consider that this analysis would is not likely to be included as part of the Commission's assessment of the rule change.

5.4.2 Specific GPS requirements for inverter-based generation

During one of our technical working group meetings, it was suggested that the Commission investigate the potential need for generator access standards that are tailored specifically to IBR. We note that this may have some merit, however it is a broader issue than the issues raised in the *Efficient management of system strength on the power system* rule change request, which focuses on issues with the current system strength arrangements.

The Commission considers this is best suited to be part of the more holistic GPS review occurring in 2023, rather than in this review.

6 EFFICIENT COORDINATION OF SUPPLY AND DEMAND: SYSTEM STRENGTH MITIGATION REQUIREMENT

BOX 5: SUMMARY OF KEY FINDINGS

The Commission considers that a system strength mitigation requirement (SSMR) should replace the existing 'do no harm' arrangements. The SSMR is designed to send price signals to generators, to support the most efficient balance and coordination between the supply and demand for system strength. Getting this balance right will help to keep costs as low as possible for consumers in the long run.

At a high-level, this requirement will retain and improve on elements of the existing 'do no harm' arrangements, while reflecting the increased provision of system strength from the supply side reforms. This involves:

- Providing clear price signals, based on the marginal cost of providing system strength, for new generators who demand system strength connecting both inside and outside of system strength zones.
  - For generators who choose to connect outside of the system strength zones, these price signals to be sent through remediation requirements (if required). That is, remediation requirements would apply to generators connecting in areas of the network where the system strength provided by the TNSP does not reach.
  - For generators who choose to connect within a system strength zone, these price signals will be sent through a charge with that charge being equal to the efficient marginal costs of the TNSP providing additional system strength to support that IBR generator's stable operation.
- It would also have the effect of incentivising generators who would provide system strength to the system to locate in areas where system strength may be needed.

Part of the SSMR is the establishment of **system strength zones.** These are the areas inside which system strength proactively provided by TNSPs, can be effectively used by generators to facilitate their connection and stable operation. These zones will be based on the physics of the service and electrical distance.

A key objective of this SSMR is to create clear price signals for IBR generation, based on their relative demand for system strength services, as well as to other generators, to supply system strength services. The SSMR will create incentives for generators to connect to those parts of the network where they will make the most efficient use of available system strength, while also bearing some portion of the costs of providing system strength.

These signals work in tandem with the new access standards that encourage generators to be capable of operating at lower levels of system strength, and should be as simple and predictable as possible to support investment decisions.

Additionally, such incentives would also enable new connecting generators to consider the costs of remediating adverse system strength (if their impact would be negative) impacts when making investment decisions. This will enable generators to consider the most cost effective solutions and contribute to reducing the overall costs of new generator connections to the system.

The system strength in a network area is dependent on the *supply* of a strong voltage waveform, relative to the *demand* for a strong voltage waveform from inverter-based resource (IBR) generation. This relationship means that an overall improvement to voltage waveform stability may be achieved by:

- *increasing* the provision of strong voltage waveforms, such as that provided by a synchronous machine, like a generator or condenser
- *decreasing* the demand of IBR generators, by sending price signals that accurately reflect the marginal cost of meeting that demand (in addition to the recommended new standards, which will act to drive efficient demand from all connecting IBR generators).

The Commission has designed the SSMR to send price signals to generators, to support the most efficient balance between the supply and demand for system strength. Getting this balance right will help to keep costs as low as possible for consumers in the long run.

The recommended system strength mitigation requirement (SSMR) evolves the existing 'do-no-harm' mechanism, while recognising the key limitations of that mechanism. It has also been designed to complement the supply side reforms discussed in Chapter 4, which will provide needed levels of system strength on a proactive basis, at specified nodes within the power system. The SSMR evolves this by establishing *system strength zones*, which correspond to defined areas around the identified system strength nodes, inside which system strength is proactively provided by TNSPs in accordance with the system strength standard.

The SSMR creates clear and consistent price signals for generation, by:

- levying a charge on grid following IBR generators who connect within the system strength zone, based on the marginal cost of meeting their demand for system strength provided by the TNSP, and
- requiring those generators who locate outside of the zone to undertake remediation works to provide their own system strength
- signal to generators who supply system strength where they should locate because system strength is needed.

The SSMR will create clear incentives for IBR generators locating inside and outside of the system strength zones.

- Grid following IBR generators who locate:

    - within the zones will face a charge based on the extent to which they create a demand ("use up") the available system strength provided by the TNSP. Using electrical distance as a proxy for how much system strength is demanded, IBR generators who elect to locate close to the node will generally face a lower charge, while those who locate further away (but still within the system strength zone) will face a higher charge.
    - outside of these zones will face remediation requirements to address their system strength impact, as per the current framework. This will include going through the full impact assessment process, and then undertaking any needed remediation actions. In effect, these IBR generators will bear the cost of providing their own system strength.
- Generators who provide system strength (like synchronous generators and grid forming IBR) are:
    - incentivised to locate within the zone through potential network support agreements with TNSPs for supplying the system strength, and will not have to pay any charge.
    - disincentivised to locate outside the zone as they will not be able to provide non-network solutions to TNSPs for the provision of system strength. However, they will not pay a charge or have to undertake any remediation to connect.

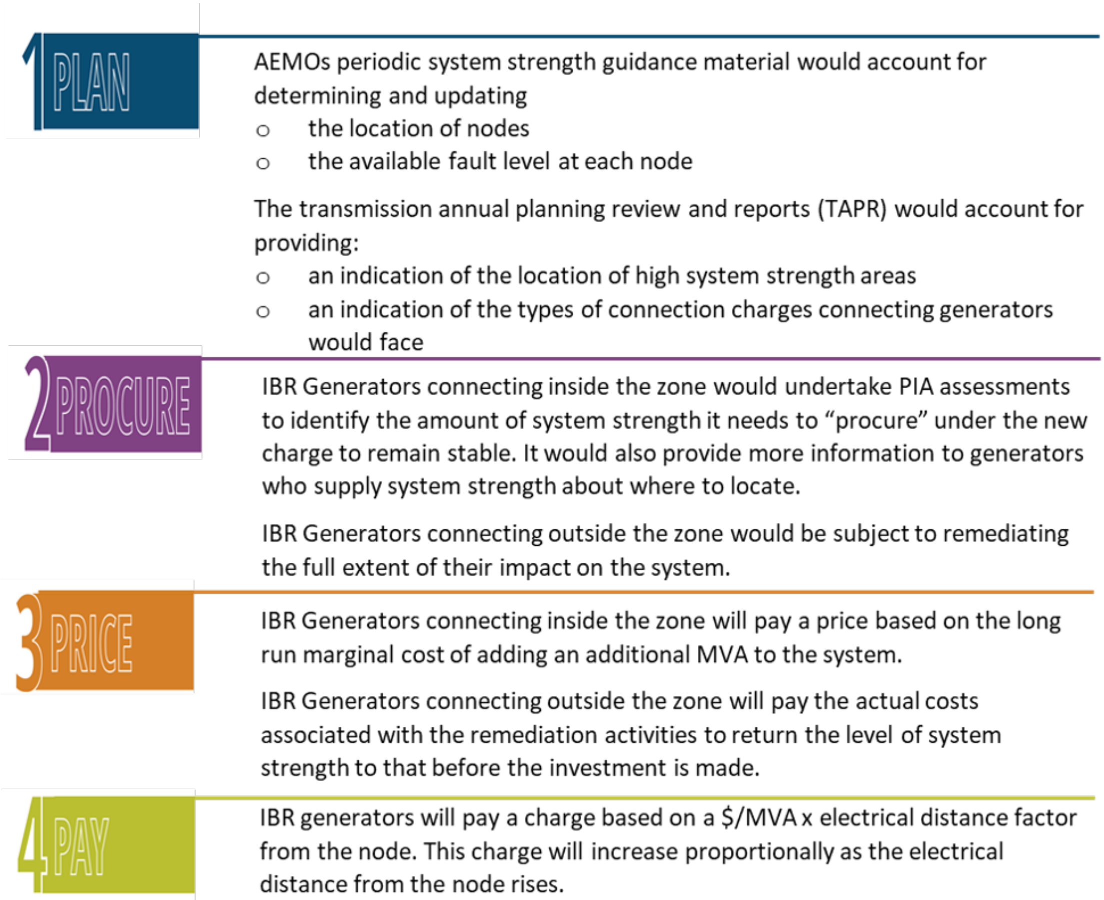
We consider that the SSMR would provide generators with the ability to choose between taking on their own costs of remediating adverse system strength impacts, supplying system strength, or utilising the system strength provided under the evolved framework, when making investment decisions. This will enable generators to consider the most cost effective solutions and contribute to reducing the overall costs of new connections to the system.

The SSMR is recommended to replace the existing 'do no harm' arrangements. Stakeholders had noted that those arrangements may have become a deterrent for investment. This comes mainly due to the uncertainty created around potentially significant system strength remediation costs incurred by some generators late in the connection process.

The recommended changes will address these issues with the existing framework, as well as creating incentives that will result in the lowest overall system cost, which is in the long-term interest of consumers.

How the recommended requirement is planned for, procured, priced and paid for is set out in Figure 6.1 below.

Figure 6.1: System service design framework for the system strength mitigation requirement



Source: AEMC

This Chapter sets out the Commission's key considerations in developing the SSMR. This includes explaining the incentives we expect generators will face under the SSMR, the rationale for the creation of system strength zones and the details of the SSMR itself.

6.1 Creating efficient incentives for generators

The Commission considers it appropriate to create incentives for generators to help coordinate the overall demand and supply for system strength. The introduction of a generator charge could be used to create such incentives.

As discussed in Chapter 2, due to the physics of their operation, grid following IBR generation require stable voltage waveform in order to operate effectively. As this creates a demand for additional system strength, it also results in a cost associated with procuring the assets and services needed to maintain adequate levels of system strength.

Two ways in which IBR generators can help reduce these costs is by:

- improving the capability of their inverters, which is addressed through our recommended reforms to the generator access standards, set out in Chapter 5.
- connecting in areas of the power system with relatively high levels of system strength, such as within close proximity of a node where system strength will be proactively provided under the evolved framework. This reduces the demand for additional volumes of system strength, by making better use of what is being made available. This also allows for economies of scale in the provision of system strength to be realised.

Introducing a generator charge based on the marginal cost of providing system strength creates incentives for generators to make efficient locational decisions, and install equipment, that helps to reduce overall system costs. This is because the generator is facing the incremental cost of providing system strength needed to support the stable operation of their equipment. This means that investment decision can take into account total system costs, as opposed to just the costs associated with the project. It also means that it will be clearer where system strength is needed, so that generators who supply system strength can connect in those locations.

This section explores these concepts in more detail, considering the ideas of marginal pricing, and how this is relevant to the investment and locational signals faced by generators. We then step through the key principles on which the SSMR has been developed, which are based on these concepts.

6.1.1 Marginal cost pricing creates appropriate incentives

The Commission considers that the charges introduced under the SSMR should be based on marginal cost pricing. This will promote efficient outcomes and the lowest overall system costs.

Marginal cost refers to the additional expense incurred to produce one extra unit of output. Marginal cost is a critical concept in microeconomics and economic regulation.

Marginal cost pricing leads to efficient outcomes

Changing an amount that reflects the marginal cost price results in efficient outcomes and the lowest overall system costs. This is explained in the following excerpt from Kahn:[79]

> *"The reason is that the demand for all goods and services is in some degree, at some point, responsive to price. Then if consumers are to decide intelligently whether to take somewhat more or somewhat less of any particular item, the price they have to pay for it (and the prices of all other goods and services with which they compare it) must reflect the cost of supplying somewhat more or somewhat less – in short, marginal opportunity cost. If buyers are charged more than marginal cost for a particular commodity … they will buy less than the optimum quantity; …if price is below incremental costs … production of the products in question will be higher than it ought to be."*

79 '*The Economics of Regulation – Volume 1*', Alfred Kahn, p 65.

Market participants exposed to system-wide marginal costs of providing system strength will be incentivised to act in a manner which minimises their own costs, contributing to a reduction in total system costs. For example, such incentives would encourage IBR generators to improve their capability to reduce their demand for system strength or locate close to the node to reduce their consumption of system strength. Alternatively, generators that supply system strength will be incentivised to locate in areas where system strength is needed.

Charging an amount different from the marginal cost would incentivise inefficient behaviour:

- Charging *less* than the marginal cost may incentivise an generator to invest in a location and install plant with technical characteristics that utilises more than the efficient level of system strength, imposing further costs on the system to provide an inefficiently high level of system strength
- Charging *more* than the marginal cost may disincentivise generators from investing and utilising the system strength that has been provided or could be provided efficiently.

There are both short run and long run notions of marginal cost. The distinction is whether all factors of production are fixed or can be varied. For example:

- the short run marginal cost is the cost incurred to produce one extra unit of output, holding at least one factor of production constant
- the long run marginal cost is the cost to produce one extra unit of output assuming all factors of production can be varied.

The most appropriate marginal costing methodology for the purposes of the evolved framework is long-run marginal costs (LRMC). This is because a short run marginal cost regime is likely to take some time to implement, during which the current arrangements would continue to result in inefficient outcomes.

Additionally, there is precedent for such an approach in the calculation of distribution network tariffs, where "*each tariff must be based on the long run marginal cost of providing the service to which it relates*".[80]

Recovering residual costs in the least distortionary way

Under a model where generators pay a charge for system strength based on marginal cost, the TNSP will still have to recover its efficient costs of meeting its regulatory obligations, which includes meeting the system strength standard. Given that the TNSP will have only recovered the *marginal cost* from generators, it follows that another mechanism is needed for the TNSP to recover the rest of its *total costs* (bearing in mind that a TNSP's revenue is based on efficient costs to meet its entire regulatory obligations, not specifically those for system strength). In developing this mechanism for recovery of the residual, it is important to minimise any potential distortionary impacts on the effectiveness of the incentives sent by marginal cost pricing.

80 Clause 6.18.5 (e) of the NER.

The principled approach to recover residual costs (those not recovered through marginal cost pricing) is to do so in a manner that is least distortionary to production and consumption decisions. That is, to recover the costs from the participant who is least affected by the recovery of those costs. In this situation, this is best achieved by recovering from consumers via TUOS charges. While consumers' consumption decisions may be impacted by these charges, the incremental change to TUOS charging for any individual consumer will be relatively low, given that the residual costs will be spread widely over a large base, meaning any impact is likely to be very modest.

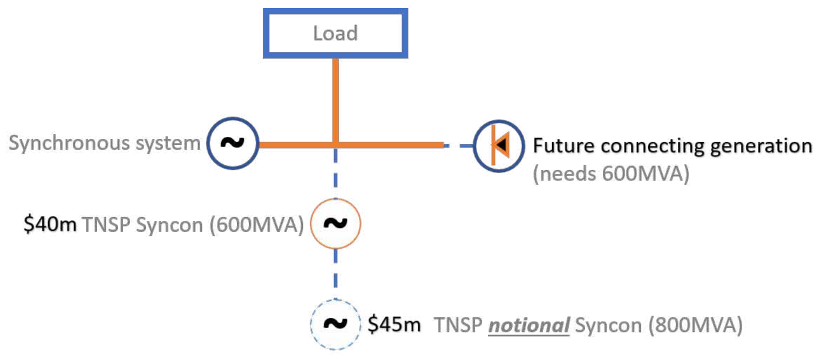
An alternate is to charge connecting generators some, or all, of the residual cost (i.e., so that the face a higher proportion of the actual costs). However, because generators would be being charged at an amount higher than the marginal cost, this might discourage the efficient utilisation of system strength. Charging connecting generators some or all of the residual charges would only be appropriate if this was considered to be the least distortionary way of recovering these costs.

BOX 6: LONG RUN MARGINAL COST PRICING - A WORKED EXAMPLE

Figure X presents a simple illustration of a transmission network which is expecting the connection of a given volume of future generation. The TNSP is under an obligation to procure additional fault level to support these future connecting generators. This future generation will require an additional 600MVA of fault level to remain stable. There is also the chance that additional generators may connect to the network which would require the TNSP to provide additional MVA. The question is, what is the appropriate price were an additional 200MVA be required?

This example illustrates the application of a specific method for estimating LRMC to derive charges for 'system strength'.

Figure 6.2: Determining the marginal cost



Source: AEMC

The TNSP meets this obligation by procuring a synchronous condenser. For the purposes of illustration, the cost of the synchronous condenser to provide 600MVA is set at $40 million. We have also assumed that synchronous condensers come in limited sizes and the next available unit size is 800MVA and costs $45 million. Therefore, an *estimate* of the marginal cost (the cost of adding an additional 200 MVA to the network) will be the difference in the unit cost, divided by the difference in MVA of each synchronous condenser.[1]

$$Marginal\ cost = \frac{(\$45m - \$40m)}{(800MVA - 600MVA)} = \$25{,}000/\mathrm{MVA}$$

This approach for determining the marginal cost of adding additional MVA to the network underpins the pricing approached used in the worked example in the following section. For the purposes of these worked examples the marginal cost is assumed to be $25,000 / MVA as demonstrated above.

Note: In this example, the "additional production" causally responsible for "future costs" is the connection of future uncertain connecting generation. The "future costs" are considered to be the costs of adding the additional 200 MVA to the system. Therefore, the marginal cost in this example is determined to be the dollar value of adding additional MVA to the system. [1] This method is called the "average incremental cost approach", and has been simplified for the purpose of the example. Other methods for estimating the LRMC exist, such as the perturbation approach. The AEMC does not have a preference in approaches employed at this stage, and it may be appropriate for another party, such as the AER, to determine the best method to use.

6.1.2 Investment price signals regarding system strength

New connecting generators should face incentives to invest in capabilities that reduce either increase the supply of system strength, or reduce their demand for system strength.

IBR generators can be broadly categorised into two distinct classifications of capability in the context of system strength:

- **Grid following inverters:** do not contribute any system strength to the power system and instead rely on tracking or "following" a strong voltage waveform in order to remain stable and synchronised to the grid.
- **Virtual synchronous machines** or **grid forming inverters:** can create their own voltage reference and do not need a reference from the system. Therefore, IBR generators with virtual synchronous machine capability possess the ability to create their own stable voltage waveform. These inverters will not "demand" system strength in the same way as grid following inverters in order to remain stable. These types of IBR generators may in fact contribute to the strength of the power system.

Therefore, the Commission recommends that a charge be introduced that incentivises generators who demand system strength to invest in plant with better capabilities, and in doing so reduce their demand for system strength. This charge should be introduced within the areas that a TNSP is proactively supplying system strength (as set out in Chapter 4) to reduce the total system costs.

The recommended SSMR creates incentivises for IBR generators locating outside of the zone to install equipment that reduces their demand for system strength. This will occur as a natural outworking of the remediation obligations that these IBR generators will face.

This will also provide more information to synchronous generators and grid forming IBR looking to connect to the network about where system strength is needed, and where they should locate - how they can contract with TNSPs to supply system strength is discussed more in Chapter 4.

A further extension of this is the use of grid forming inverters that have been used and proven for several decades in uninterruptible power supplies and in microgrids.[81] However, at present, AEMO considers that international examples suggest that the operation of grid-forming inverters in utility-scale power systems remains unproven.[82] The Commission considers that this technology has the potential to provide a number of benefits to the power system in the future, and may help to reduce the cost of providing system strength. We have identified several areas where we consider further work is needed to effectively integrate this technology into the NEM power system. We look forward to working with industry, AEMO and other interested stakeholders to progress this work.

6.1.3 Locational price signals regarding system strength

Generators should face incentives to locate in areas of the network where they make can make the most efficient use of the system strength that has been proactively provided by TNSPs under the evolved framework. Where generators elect to locate in remote, electrically distant parts of the system, with that increasing the demand for system strength in that area, they should face the costs associated with that decision.

The basis of such locational signal requires consideration of the locational characteristics of system strength. That is, sources of system strength, such as a synchronous condenser or other synchronous machine, are most effective at improving system strength at the point at which it connects to the network. However, as you move away from the synchronous source, the level of additional system strength will diminish as a function of impedance (electrical distance).

Therefore, generators that increase the demand for system strength that connect electrically distant from a node being maintained by the TNSP, must "consume", or create a demand for, a greater volume of system strength in order to remain stable. While the recommended access standards discussed in Chapter 5 imposes some constraints on generators in terms of the system strength demanded, these new access standards do not reflect the marginal costs incurred by the TNSP as a consequence of locational decision of each IBR generator, and so may not, in and of themselves, incentivise efficient behaviour.

The SSMR would introduce a charge that takes account of the electrical distance from the node, to send a locational signal to better incentivise efficient behaviour from new connecting generators. This charge would serve to send locational signals to generators who demand system strength to locate in parts of the network with greater levels of system strength; and conversely locational signals to those generators who supply system strength to locate in those areas that system strength is needed.

81 Power Systems Consultants, *Review of AEMO's PSCAD Modelling of the Power System in South Australia*, December 2017, p. 22.

82 AEMO, *Power System Requirements*, March 2018, P. 15, Available at: www.aemo.com.au.

For example, the charge would increase proportionally as the electrical distance from the node rises. Take for example a new connecting IBR generator. This generator will make a trade-off between paying:

- a charge determined through the formula as a function of a locational decision, or
- the immediate, actual costs associated with the remediation activities to return the level of system strength to that before the investment is made.

Generators will be incentivised to choose the lesser cost of such a trade-off and be encouraged to locate electrically close to the node maintained by the TNSP. This will promote the coordination between the demand and supply.

6.1.4 Design principles for the SSMR

From these considerations, the Commission considers the following design principles should guide the design of a charging mechanism for system strength. These design principles aim to support the recommended SSMR achievement of the NEO, particularly as it applies to the principles outlined above - relating to promoting, appropriate risk allocation, transparency, predictability and simplicity.

These design principles are:

- **Send clear investment and locational price signals,** through a marginal cost pricing approach. This should incentivise generators to:
    a. Install equipment that further reduces their demand for system strength, and reduces the need for the TNSP to invest in further centralised provision of the service. In practice, this mechanism should incentivise generators to select synchronous generation equipment (virtual or otherwise) where it is efficient to do so, because the incremental cost of doing so is less than the cost of the system strength charge. For example, this will likely incentivise generators to select ‘grid forming’ rather than ‘grid following’ inverters when developing a new generating system, when the cost of doing so is efficient.
    b. locate efficiently, for example in the areas where system strength has been proactively provided by TNSP if the generator demands system strength; and in areas where there is little system strength if the generator supplies system strength.
- **Share the costs of system strength between customers and generators.** The Commission considers that both parties receive a benefit from the provision of system strength. On that basis, we consider that both should bear some of the costs of providing these services.
- **Transparency, predictability and simplicity.** The recommended charge will be simple, transparent and predictable. The Commission considers the charge will be based on a dollar per system strength unit ($/MVA) multiplied by electrical distance factor from the node. This simple concept should be easy to predict and enable generators to estimate the costs they are likely to face far in advance of making any final investment decisions, while still being a reasonably representation of marginal costs**.**

6.2 Considerations for system strength 'zones'

This section explores the concept of system strength zones. These zones are a fundamental element of the SSMR, in that they define how generators pay for system strength. In defining these zones, we need to consider the physics underpinning system strength, and then how the physics can be effectively mapped to an efficient charging regime. These zones are different to a zonal approach to the standard, which is based on geographically defined areas.

System strength is a relatively location-specific service, as discussed in Chapter 2. The system strength at any given location is primarily determined by the number of:

- synchronous machines nearby that are capable of being the source of a stable voltage waveform, and
- relative impedance of transmission lines or distribution lines (or both) connecting synchronous machines to the rest of the network.

Such an area cannot easily be geographically or symmetrically defined around a node or a source of system strength, without consideration of system strength's locational characteristics. Expressed another way, a zone in which system strength can be used has a boundary that must reflect the physics of the provision of system strength.

The locational characteristics of system strength are such that network solutions - such as a synchronous condenser - are most effective at improving system strength at the point at which it connects to the network. However, as you move away from the synchronous condenser the level of additional system strength will diminish.

Therefore, a **system strength zone** can be described as the area inside which system strength - that has been proactively procured by TNSPs - can be effectively used to facilitate the connection and operation of grid following IBR generation. These zones are distinct from a zonal approach to a system strength standard (discussed in Appendix B3), which are based on geography rather than electrical distance as being discussed with these zones.

6.2.1 Impedance and electrical distance

A primary network characteristic which influences the extent to which system strength diminishes is network impedance.

Impedance is a characteristic of the network which can resist the “flow” of system strength. A higher voltage or larger transmission line will typically have lower impedance than a lower voltage, smaller transmission line. Furthermore, the shorter the route length is, the less the reactance (and resistance) and hence the lower the impedance will be. Lower impedance basically means there is a wider area over which system strength services will propagate. Electrical distance is equivalent to impedance.

Considering electrical distance therefore is conceptually comparable to measuring the distance between two locations in terms of “travel time”. If the locations are connected via a fast highway the travel time between each location will be short, if they are connected via a winding slow road the travel time will be long. Therefore, higher impedance leads to a longer "travel time" resulting in greater electrical distance.

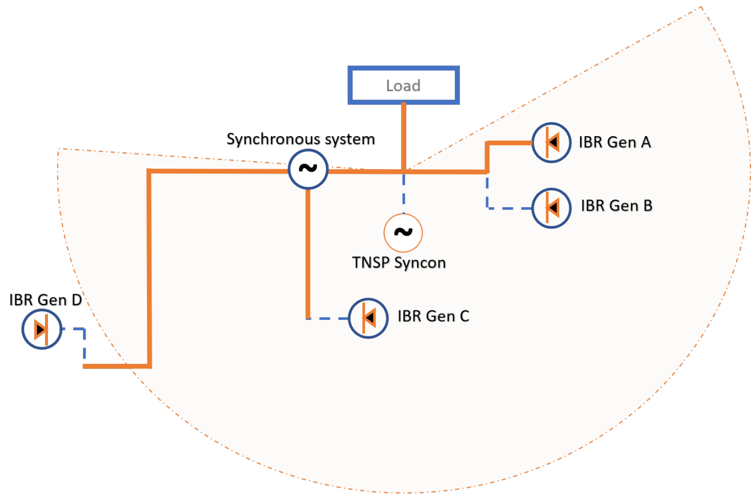
6.2.2 Boundary of a system strength zone

The Commission considers that the boundaries of a system strength zone are best informed by taking account of the electrical distance from a node where the TNSP faces an obligation to maintain system strength under the evolved framework. These boundaries would not be geographically symmetrical but would notionally reflect a limit beyond which a connecting IBR generator would be so electrically distant that any "consumption" of system strength provided at the node is not physically possible.

Therefore, the boundary limit of a zone may be defined as a connection point at which the generator can no longer benefit from the available system strength due to its electrical distance from the source.

Such a zone might be reflected as illustrated in Figure 6.3. The zone, illustrated by the shaded area, represents an area within which connecting generators can realistically utilise the available system strength and connect without the need to undertake remediation. Figure 1.3 illustrates that generator D is determined to be electrically remote from the node or source that the TNSP is required to maintain. Generator D would therefore be considered to be outside of the zone and be required to undertake remediation for its full system strength impact on the system.

Figure 6.3: **Considering the concept of a system strength zone**



Source: AEMC.

Note: The boundary zone illustrated in the above figure denotes is purely for the purposes of denoting generators who can consume available fault level and those who cannot. In reality, the boundary of such a zone will not be symmetrical.

6.3 The system strength mitigation requirement

Under the Commission's evolved framework, the SSMR would replace the existing 'do no harm' arrangements.

At a high-level, this requirement will improve the elements of the existing 'do no harm' arrangements while acknowledging the increased provision of system strength from the supply side reforms, including:

- Locational and investment price signals regarding system strength for new connecting generators connecting both inside and outside of system strength zones.
- Remediation requirements for generators outside of system strength zones. That is, IBR generators connecting outside of the network area where a TNSP's proactively supplied system strength physically applies.
- Recover a contribution equal to the efficient long run marginal costs (associated with the TNSPs central procurement of system strength) incurred by the TNSP as a consequence of a new connecting generator, where the generator demands system strength
- Better investment signals for generators who supply system strength to locate where it is needed, and potentially supply it to the TNSP - see Chapter 4 for further detail on how this occurs.

To achieve this, these requirements will encourage generators to locate in high system strength areas of the grid, being those where system strength is being proactively provided by TNSPs.

This reform addresses the issues raised by stakeholders with the existing 'do no harm' arrangements, especially those regarding the uncertainty in relation to cost placed on generators late in the connection process. Generators will face a charge reflective of the marginal cost of providing system strength. The reform aims to make the nature and extent of such a charge available to generators as early as practicable. In is anticipated such a charge could be estimated at the preliminary impact assessment (PIA) stage, providing generators with predictable and transparent costs greatly improving investment certainty.

New connecting grid following generation will face different charges when connecting to the network under this charging approach. Table 6.1 below outlines a summary of the locational charges a new connecting inverter based generator would face.

Table 6.1: **How the charging options would apply to a new connecting generator**

CONNECTING GENERATOR OPTIONS	NEW CONNECTING GRID FOLLOWING IBR GENERATOR	NEW CONNECTING GRID FORMING IBR OR SYNCHRONOUS GENERATION
Connect electrically close to the node inside the zone	Pays a charge proportional to the generator's consumption of system strength (MVA)	Does not pay a charge or undertake remediation May be able to supply

CONNECTING GENERATOR OPTIONS	NEW CONNECTING GRID FOLLOWING IBR GENERATOR	NEW CONNECTING GRID FORMING IBR OR SYNCHRONOUS GENERATION
Connect electrically distant from the node but inside the zone	Pays a charge proportional to the generator's <u>increased</u> consumption of system strength (MVA)	system strength to the system by contracting with TNSPs
Connect electrically remote from the node outside the zone	Undertakes full remediation of their impact on the local system strength	Generator intrinsically provides its own system strength to support its own connection

6.3.1 Requirement on generators connecting inside a system strength zone

Generators inside a system strength zone that demand system strength would be required to pay a contribution proportional to the system strength it uses. These funds would then reduce the total amount of TUOS charges consumers pay each year.

The Commission consider such a mechanism would be relatively predictable and would enable a charge that would be relatively easy to calculate early in the PIA process. This would enable generators to estimate the indicative charges they would face prior to connection, or the potential revenue they could receive from supply system strength, and so better consider the implications of where they choose to connect.

A formula would determine the total amount that a new connecting IBR generator would be required to pay. This formula has three components, as shown in an illustrative manner in Figure 6.4.

Figure 6.4: Illustrative formula for generator connection charge (inside a system strength zone)

Total generator charge ($) = System strength impact charge ($/MVA) X System strength need (MVA/MW x MW) X Location factor

Source: AEMC

Therefore, connecting generators that demand system strength would face a charge that would be reflective of the amount of system strength they would need to consume to remain stable. This charge would aim to reflect the actual consumption of system strength (as measured by fault level) but may involve some degree of approximation. However, the charge would take into account the electrical distance of the generator from the node or source of system strength, which provides a reasonable approximation of the generator's consumption of available system strength.

The formula used to determine this connection charge is set out below.

System strength impact charge (green)

This portion of the formula is a dollar per system strength unit ($/MVA) charge that reflects the marginal cost of adding 1 MVA of system strength to the system. The charge would be based on the LMRC of the TNSPs central procurement of system strength.

This portion of the formula would be transparently designed as it is the only portion that is not dependent on the connecting generator. As such, the Commission is exploring different options for this charge, including having it:

- calculated by TNSPs and approved by the AER,
- TNSPs setting out the charges in its TAPR for some time period (potentially 3 years) in advance.

This is to provide connecting generators with greater investment certainty in relation to the costs being faced at the point of connection, which is an emerging issue with the current arrangements. The Commission will be engaging with stakeholders regarding the nature and granularity of this impact charge through our assessment of the *Efficient management of system strength on the power system* rule change request from TransGrid, to develop a more detailed design for consultation in the draft determination.

System strength need changes with generator system strength capabilities (yellow)

The principle underpinning this mechanism would be such that a generator would face a price somewhat reflective of its consumption of system strength (MVA) at its connection point. It is expected that a grid forming inverter with virtual synchronous capability, or synchronous generator, would have the capability to provide its own voltage waveform and therefore would face either a lesser or possibly no charge, depending on capability. These generators would have incentives to locate where system strength is needed and so potentially contract with TNSPs to supply system strength.

Grid following inverters on the other hand do not create their own voltage reference and therefore must follow the grid voltage waveform seen at their terminals to operate. These inverters will inject current at an angle that tracks the measured voltage, "sensed" from the grid, in a process known as phase-locked-loop. Following the occurrence and clearance of a fault, the grid following inverter must re-lock onto the grid to ensure stable control. In weak system strength conditions (low fault level environments) the phase angle shift will be larger than that experienced in stronger systems (high fault level environments) making the ability for the grid following inverter to remain locked to the system much more difficult.

Therefore, grid following inverters can be considered to "demand" system strength to ensure stable operation following a fault. As such, they would have a positive value for this variable and would likely pay a charge if locating outside particular areas.

System strength location factor changes with electrical distance (orange)

This portion of the formula would see an generator that demands system strength s costs change based on their proximate electrical distance from a designated node or source of system strength. This would result in these generators facing an increased charge if they locate further from a node or point source of system strength.

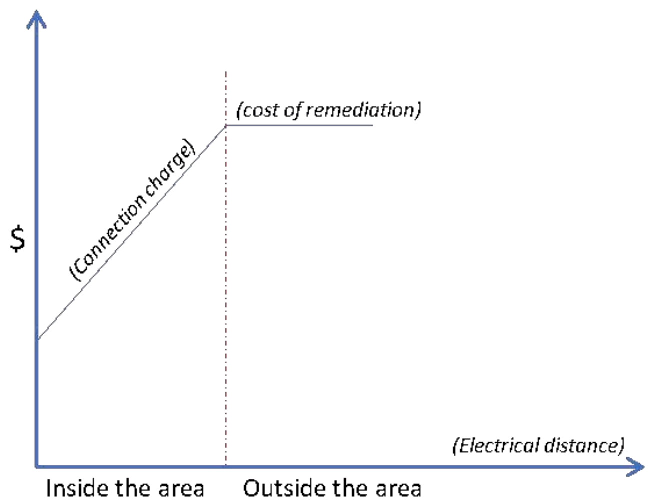
For example, if the generator is connecting close to a node maintained by the TNSP it would pay a charge somewhat reflective of its consumption of MVA at its connection point. If it connects in an area of the grid that is electrically distant from the node, the IBR generator will pay a charge proportional to its increased consumption of system strength (MVA).

By accounting for AFL and electrical distance, this charge would send a price signal to generators to further reduce their demand for system strength. This would be done by reducing this charge by taking action to either locate closer to the node. That is, reducing their consumption of system strength.

This pricing approach would increase the charge proportionally as the electrical distance from the node rises, eventually rising to a cost that exceeds the cost of generator undertaking its own remediation.

Figure 2 below highlights how this charge would conceptually increase as a generator chooses to connect in an electrically distant location from the node (although the exact shape of the graph may differ in practice).

Figure 6.5: Illustration of charge changing over distance



Source: AEMC

The red line in Figure 6.5 represents the boundary of the zone beyond which the connecting generator is so electrically distant that consumption of fault level is not physically possible. As a generator chooses to locate further from the node and closer to the boundary the charge a generator would face would increase.

The charge would increase, with electrical distance, to a point where it exceeds the full incremental cost of returning the level of system strength to the level before the generator's investment is made, as shown in the figure. This sends locational signals to generators to locate close to where a TNSP is maintaining the available fault level to avoid increased charges.

6.3.2 Requirement on generators connecting outside a system strength zone

Generators that demand system strength would be required to undertake a full remediation of their impact on the local network's system strength when connecting outside a system strength zone. That is, such a generator will be required to procure the necessary volume of its own system strength commensurate with its impact, such that the generator's connection does not adversely impact on the ability of the power system to maintain system stability or on a nearby generating system to maintain stable operation, similar to the existing arrangements.

This requirement would apply when a new connecting generator wishes to connect electrically distant from the coordinated, proactively procured system strength (of a system strength zone) such that the service cannot facilitate its connection. That is, to locate outside of the system strength zone.

This requirement would leverage the existing full impact assessment (FIA), the undertaking of which is contingent on the results of a connecting generators PIA, alongside the processes and knowledge gained from experience since the system strength framework was introduced in 2017. The assessment would be for the security of the system, that is the stability of the power system and the ability of new connecting and nearby IBR generators to maintain stable operation, rather than in reference to any minimum system strength levels.

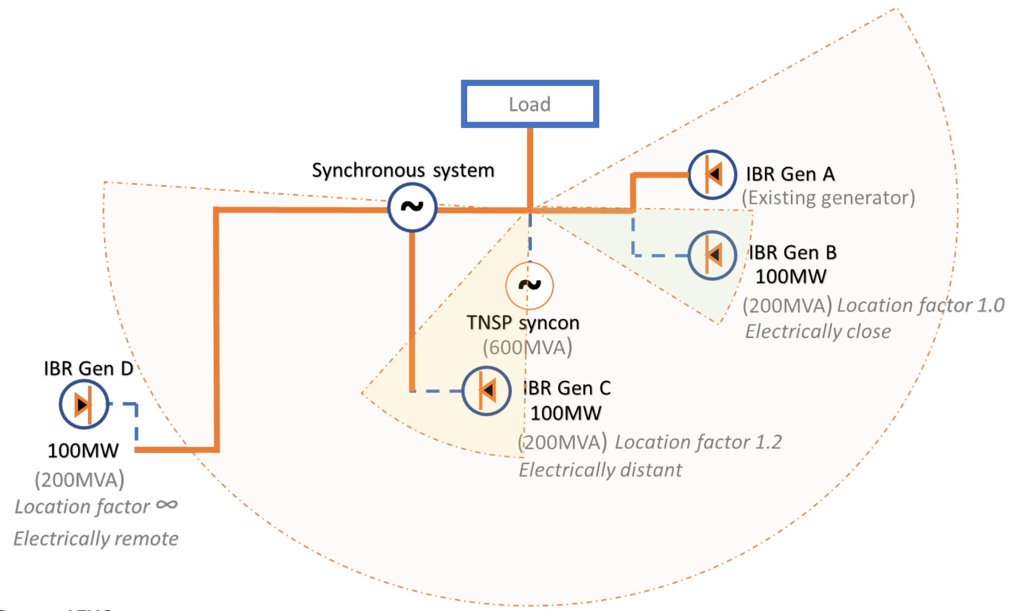
As with the existing arrangements, an generator undertaking these works can still engage the TNSP to assist or undertake the remediation work. Additionally, generators and TNSPs will still be able to coordinate these remediation works where (small level) economies of scope and scale are available.

BOX 7: WORKED EXAMPLE OF THE APPROACH

This is a worked example of how the system strength mitigation requirement is expected to work for four generators, all located different distances from a system strength node.

Assume that IBR generators B and C, as described in Figure X, are connecting to the network and locating within a system strength zone. These generators will be required to pay a charge for connecting within the zone, but not required to undertake any remediation as the system strength is being provided by a TNSPs proactively. Generator D is locating outside a system strength zone.

Figure 6.6: Implications of connection location on generator charges



Source: AEMC

Generator A

As an existing generator, Generator A would face no charge.

Generator B

Let's assume Generator B is a 100MW generator and requires 200MVA to remain stable. As set out in the example above, we assume the marginal cost of adding an additional 1 unit of system strength (MVA) to the system was $25,000 per unit (MVA). As illustrated in the figure, Generator B is determined to be electrically close to the node. Therefore, Generator B's system strength impact connection charge would be 200MVA x $25,000 x 1 x (Location factor) = $5 million for connecting inside the zone.

Generator C

Generator C is also assumed to be a 100MW generator requiring 200MVA and connecting within the zone. However, the figure also shows that generator C is more electrically distant than Generator B from the node. The implications of this are that in reality Generator C will consume more fault level than Generator B in order to remain stable. Therefore, in this charging model inverter-based Generator C will pay a greater charge than Generator B. This is because electrical distance is considered as part of the charging mechanism. Generator C will therefore pay a greater charge than inverter-based Generator B.

As an example, Generator C could face a location factor of 1.2. Generator C would therefore face the following charge: 200MVA x $25,000 x 1.2 x (Location factor) = $6 million. This would be an additional $1 million compared with the location of Generator B. This approach would not only encourage generators to locate within the zone, but also encourage generators to locate electrically close to the node within the zone.

Generator D

Generators locating in remote locations, as is the case with Generator D in the above figure, would face the full remediation costs of their system strength impact. The cost of remediation facing the generator will likely exceed the marginal cost based charge it would face if it located inside the zone, reflecting the fact that the marginal costs of system strength outside of the zone will likely be higher than those associated with the provision of system strength through the coordinated processes inside the zone. Generator D would therefore face strong investment signals to locate inside the node and additional signals to locate closer to the node.

Note: The figures used in this example are for illustrative purposes only.

7 CONSIDERATION OF DISTRIBUTION NETWORKS IN THE EVOLVED FRAMEWORK

BOX 8: SUMMARY OF KEY FINDINGS

The Commission has concluded that the current arrangements regarding system strength, as applicable to distribution networks, do not require any changes in an evolved framework at this point in time, given that the changes to the evolved framework at a transmission level will flow through and have positive impacts on the use of system strength at the distribution networks.

The current arrangements for system strength, relative to distribution networks are that:

- TNSPs are *system strength service providers.*
- DNSPs would however continue to have a role, as is the case under the current arrangements, by collaborating with TNSPs regarding network design under the existing joint planning obligations of TNSPs and DNSP.
- generators connecting within distribution networks would continue to do so under the system strength mitigation requirement (SSMR).

Additionally, an evolved framework's system strength network standard will provide TNSPs a greater ability to proactively procure greater levels of system strength. These benefits will also flow on to the distribution network as well the transmission network.

While this focus was system strength issues in the transmission networks, the Commission also queried whether there were any material emerging issues in distribution networks. Stakeholders were encouraged to provide their experience and insights in submissions to the discussion paper earlier in the year to better inform consideration of distribution networks in an evolved system strength framework.

The Commission has since engaged with DNSPs,[83] AEMO and our technical consultant (GHD) to further explore the substantive issues raised by stakeholders. This Chapter outlines our analysis and conclusions on this issue.

7.1 Existing system strength arrangements for distribution networks

The Commission has previously considered the role of the DNSP in the system strength frameworks as part of the *Managing power system fault levels* rule change (Fault levels rule) in 2017.[84]

83 There has been a DNSP representative on the four general technical working group meetings held. In addition, a specific DNSP workshop was held on the 3rd of September 2020.

84 AEMC, *Managing power system fault levels Final determination*, p. 39, September 2017.

7.1.1 DNSP-TNSP joint planning arrangements

In an interconnected power system made up of multiple transmission and distribution networks, actions in one network can impact on a neighbouring network - regardless of whether this is a transmission or distribution network.

Given the interaction between networks, the NER includes provisions for TNSPs and DNSPs to undertake joint planning of their respective networks, to assess the adequacy of their existing transmission and distribution networks to achieve efficient planning outcomes.[85]

The NER provisions require TNSPs and DNSPs to:

- undertake joint planning of projects which relate to both networks (including, where relevant, dual function assets);[86]
- use best endeavours to work together to ensure efficient planning outcomes and to identify the most efficient options to address the identified needs.[87]

This is also relevant to system strength, as the system strength at a given generating system connection point can depend on the actions of more than one NSP. For example, actions taken to increase system strength near a network boundary will increase the system strength in the neighbouring network.

7.1.2 Commission position in 2017 Managing power system fault levels final Rule

The Commission concluded that TNSPs maintaining system strength shortfalls at specified fault level nodes on the transmission network would also increase system strength in neighbouring distribution networks. As a result, the framework in the final determination and rule clearly allocated responsibility for system strength to the party who the Commission considered was best placed to manage the risks associated with fulfilling that responsibility – that is, the relevant TNSP.

The Commission's view as set out in that determination was that the most effective solution would be for TNSPs and DNSPs to undertake effective joint planning to coordinate the most effective and efficient provision of system strength. With joint planning being the preferred solution due to the interfaces between transmission and distribution networks. Additionally, the Commission considered that requiring DNSPs and TNSPs to *both* maintain system strength could lead to inefficient investment in system strength services, given that system strength in one part of the network has flow on effects on networks nearby.

Therefore, the current rules place an obligation on the TNSP (a 'System Strength Provider') in a region to make "system strength services" available following the declaration of a shortfall that would increase three-phase fault level. This service provision is to occur at fault level nodes, being the location on the transmission network for which fault level must be maintained at or above a level determined by AEMO. As a result, the current arrangements do not classify DNSPs as a system strength provider, instead relying on the joint planning provisions to deliver sufficient system strength to meet needs in distribution networks.

85 NER Clause 5.14.1 of the NER.

86 NER Clause 5.14.1(d)(1)

87 NER Clause 5.14.1(d)(2)

7.2 System strength in the distribution network

The concept of system strength can be considered in three constituent parts – voltage waveform provision, network stability management, and inverter driven stability – with the first representing the 'supply' of the service and the latter two the 'demand' as outlined in Chapter 2.

Both transmission and distribution networks are facing similar system strength related challenges. This includes the reduction of system strength / voltage waveform provision, and increased demand for system strength, caused by:

- the connection of large-scale inverter-based resource (IBR) generation
- retirement and changing dispatch patterns of synchronous generation.

However, distribution networks are also facing unique system strength challenges not present in transmission networks. This reflects the different characteristics of the different voltage levels of distribution networks.

It is most appropriately considered by separating out these issues as they are experienced in the:

- high voltage (HV, typically in the voltage range 66KV and above) and medium voltage (MV, typically in the voltage range 400V to 66kV) sections of the distribution network
- low voltage (LV) sections of the distribution network (typically in the voltage range 240-400V).

This is due to the way system strength issues manifest in distribution networks. The following section explores how system strength issues apply to these sections below.

7.2.1 System strength is not an issue in the LV distribution network

System strength in the LV distribution network is generally supplied by virtue of its connection to the higher voltage distribution network. Little to no active sources of system strength exist in the LV network.

However, submissions to the March discussion paper noted that the low voltage networks (i.e. 400V/230V) generally have relatively high fault levels, except for some rural, single wire earth return (SWER) and isolated networks, where premises may be supplied off a small distribution transformer (i.e. 15-25kVA).

The key system strength issues in this area of the network include:

- **Demand for system strength in the LV network –** A key difference between the LV and higher voltage network components, is that controller interaction phenomena (inverter driven instability) is not likely to be an issue. Or, at least not an issue in the same way that it is experienced in large-scale, three-phase inverter-connected generators on higher voltage distribution networks. The Commission understands that fault levels are generally high enough in this part of the distribution network, such that stability in that context is not a concern. DNSPs note that it is more likely that small-scale generators will trip-off due to frequency or voltage excursions, rather than system strength.

- **Network stability issues in LV network** – As with the HV & MV distribution network, the LV network consists of many thousands of individual transformers, overhead lines and cables, and each of these requires some form of protection system. Feedback from DNSPs has suggested that network stability management was not generally presenting as an issue in the LV distribution network.
- **Modelling limitations in LV network -** The LV network has additional modelling challenges when compared to that of the HV and MV network. For example, DNSPs may have low visibility of DER connections, and the measured voltage and current in each area or zone substation. This makes modelling for system strength difficult, for example, determining the system strength needs of different localities. Additionally, the LV network is much more dynamic when compared to the HV and MV network, with more frequent network reconfiguration during outages, as compared to the less dynamic higher voltage networks. This induces additional uncertainty in modelling outcomes.

Conclusion

The system strength issues considered in this review appear to be quite different to those experienced in the LV distribution network. In particular, issues related to inverter-based stability, network stability management and low fault levels are not presenting in the LV distribution network as primary concerns. Further, generator obligations under the current and evolved system strength framework only apply to generators above a 5MW threshold - many generators connected at the LV part of the network are smaller than this.

The Commission considers LV distribution network system strength issues are therefore not material at this time compared to those experienced in the higher and medium voltage distribution networks and so do not need to be considered in this review. However, they remain in focus through other current AEMC work[88] underway, such as the rule change looking at technical standards for distributed energy resources below the 5MW registration threshold.[89]

7.2.2 System strength issues in HV & MV distribution network can be dealt through joint planning arrangements

Most distribution networks are reliant on system strength being supplied from the connection point(s) connecting to the closest transmission network. System strength is therefore typically maintained in the HV and MV sections of the distribution network by virtue of the relevant TNSP undertaking actions to maintain system strength in its own network. As a result, DNSPs plan their networks with reference to the system strength available at the transmission connection point.

Physical characteristics of the HV & MV network

The availability of system strength across a distribution network is significantly influenced by:

88 *National Electricity Amendment (Technical Standards for Distributed Energy Resources)*, Rule 2020 consultation paper, June 2020.

89 AEMO have submitted a rule change request to introduce an obligation on AEMO to create a subordinate instrument for a minimum technical standard for distributed energy resources (DER) and a definition of DER in the National Electricity Rules (NER) alongside requiring DNSPs to ensure that connected DER meet the DER minimum technical standards through their relevant connection agreements.

1. network topology, including the different configuration of some parts of the distribution networks,
2. greater impedance than transmission networks – that is, the impedance of the network elements down through the network (e.g. transformers and long, low voltage lines)
3. varying impedance - impedance can vary significantly more frequently than in transmission networks, as a result of the regular occurrence of network outages needed for maintenance.

These physical characteristics of the distribution network influence the properties of system strength. For example, higher impedances will result in a more pronounced manifestation of system strength's locational characteristics, making the phenomena more location specific in distribution networks.

This has implications for the extent to which establishing nodes in the distribution network would be of practical benefit. This is because system strength issues in the distribution network tend to be highly locational, and therefore difficult to identify. Additionally, it also means any system strength solutions will result in services that are relatively "hard to share" across the network, as the "propagation" of system strength is related to the impedance of the network. This lack of effective propagation of system strength also means that any remediation of system strength issues at any nodes within the distribution network would likely not realise the same economies of scale that could be realised on the transmission network.

Inverter driven stability

As described previously in Chapter 2, the presence of large volumes of grid following IBR can impact on the stability of the voltage waveform, and is one aspect of the "demand" for system strength. The HV and MV components of distribution networks are experiencing increased penetration of grid following IBR, resulting in increasing demand for system strength.

In the HV and MV distribution network, this demand is coming from the connection of:

- **Large-scale IBR generation (5MW or greater):** As described above, an increase in the number of IBR generators in distribution networks is causing an increase in demand for system strength. This is exacerbated by the reduced supply of system strength flowing from the transmission networks to the distribution networks. Further, significant portions of large scale IBR are also locating in parts of the distribution networks that are electrically distant from synchronous generation sources. For example, in Victoria, most of the large-scale solar farms built in the last few years are connected to the HV components of the distribution networks (at 66kV sub-transmission systems). These are typically located in regional areas with strong solar resources, but where the network exhibits low system strength.
- **Small-scale IBR generation (less than 5 MW):** Generators with capacity below AEMO's registration threshold of 5 MW do not have to undergo the process of generator performance standard negotiation or the 'do no harm' arrangement. However, if multiple

such generators are located in close proximity, this can have a significant impact on system strength.

Network stability management

The HV and MV components of distribution networks consist of many individual transformers, overhead lines and cables, with each requiring some form of protection system. These protection systems require adequately damped voltage waveforms to operate effectively. This includes the maintenance of low network impedances and 'demand' for sufficient fault current to correctly operate protection mechanisms.

Declining levels of system strength in the HV & MV distribution network may negatively impact on the operation of network protection systems. The maloperation of protection systems can result in delayed fault detection and clearing, resulting in potential equipment damage and network stability issues. This is a similar issue to that experienced in transmission networks.

Modelling limitations

Historically there has been no need for DNSPs to maintain EMT (Electromagnetic transient) models[90] for their networks. However, distribution network operators are increasingly having to consider and respond to dynamic system characteristics, which were previously the domain of transmission system analysis and TNSPs. The tools, granularity of network parameter data available, and skill sets required for this analysis, are a significant change to the DNSPs' typical modelling role in the NEM.

The difficulty with modelling these networks includes:

- The lack of data availability from:
  - Small-scale generators (less than 5 MW) – as most small-scale inverter manufacturers have no ability to provide EMT models to DNSPs. This means that the limited availability of detailed EMT models for small-scale inverter-based generation connections makes modelling very difficult.
  - Loads – modelling load behaviour becomes more relevant for DNSPs when undertaking EMT modelling. The transmission network can derive precise EMT models without considering detailed load behaviour, due to the fact that most loads are located distant from the transmission network, or because there are a relatively few connected at the transmission level. However, the accuracy of the distribution network models can be greatly influenced by load behaviour and to do so would require EMT models of large disturbing loads in the network in order to improve certainty in the models. Creating models like this would therefore involve significantly

90 These EMT models are currently the most detailed representation of equipment and networks available. They are required for power system dynamics analysis, particularly critical for delivering effective assessments of system strength. EMT models are computationally intensive and require particular skills making their development a relatively expensive process. For any assessment of the power system or any of its components, it is important to have up-to date, accurate and transparent models of plant as required. Transient models provided under clause S5.2.4(b) of the NER must define the site-specific electro-mechanical and control system performance of components comprising plant under Steady State, set-point change and Disturbance conditions for all levels of system strength and energy source availability that the plant is rated to operate.

more complex input parameters than the “load equivalence” models used by TNSPs. The lack of these parameters would likely induce inherent uncertainty in modelling.

- Obtaining up-to-date information and models from multiple neighbouring network service provider areas in both transmission and distribution networks to better inform modelling outcomes.

Modelling limitations will impact:

- the ability to accurately assess system strength issues on the DNSPs network making it difficult to accurately characterise and define system strength service provider related obligations
- fault level node identification on the distribution network and the associated projection of current and future needs.

Conclusion

The Commission considers that, with respect to the system strength issues faced in the HV and MV distribution network, the current arrangements remain appropriate at this point in time. That is, that TNSP provision of system strength is sufficient to maintain adequate levels in the HV and MV distribution networks.

In an evolved system strength framework, the introduction of a system strength network standard will provide TNSPs a greater ability to proactively procure greater levels of system strength. It therefore stands to reason that the benefits and flow on effects of increased levels of system strength from provision at the transmission network will flow through to the HV and MV distribution network. Additionally, the introduction of performance and amendment of locational requirements would serve to further manage the demand for system strength from all new IBRs greater than 5MW connecting in the distribution network.

DNSPs’ highlighted, during the Commissions' stakeholder consultation, that investments on the distribution network could be better coordinated with those on the transmission network, to more effectively realise optimal system strength solutions for both parties. It was suggested that TNSPs should have “stronger obligations” to engage in appropriate consultation with the DNSP, when considering system strength solutions to meet the standard.

The Commission agrees that coordinating the most effective and efficient solutions require DNSPs and TNSPs to undertake effective joint planning, given the interaction between NSPs' networks. However, the Commission considers that the current NER arrangements relating to joint planning are already comprehensive and should be sufficient to facilitate this change. On this basis, the Commission considers there is no need for any amendment to the NER to facilitate more effective joint planning for system strength.

This is consistent with the Commission’s previous consideration of whether amendments to the existing planning arrangements in the NER[91] were required, to facilitate more effective system strength planning. The final determination for the Managing power system fault levels

91 Rule 5.14 of the NER.

Rule 2017 considered that the existing planning arrangements in the NER[92] were adequate to facilitate effective joint planning.[93]

Consistent with current arrangements, the Commission does not consider that this decision will create unintended consequences of incentives for new generation to connect in either the transmission or distribution network regarding the system strength arrangements. That is, a generator connecting in either network will have:

- similar obligations under the system strength mitigation requirement (SSMR), including paying a charge when inside a system strength zone
- the appropriate availability of TNSP proactively provided system strength with which to connect to the grid relative to their connection point.

92 Rule 5.14 of the NER.

93 AEMC, Managing power system fault levels Final determination, p. 39, September 2017.

8 CONSIDERATIONS FOR TRANSITIONING TO THE EVOLVED FRAMEWORK

BOX 9: SUMMARY OF KEY FINDINGS

The Commission acknowledges the need to evolve the system strength framework as soon as possible in order to mitigate against the cost and delays that are currently being experienced. Evolving the framework as quickly as possible will promote the long term interest of consumers.

The time taken to transition to the evolved framework should therefore be minimised as much as possible, noting that there are different costs and risks associated with the different implementation timeframes and associated transitional arrangements.

The Commission's analysis suggests:

1. It would only be appropriate to rely on the "status quo" (i.e. introduce no specific transitional mechanism) if we can be confident of a relatively quick implementation timeframe and/or no immediate system security issue(s) would be posed by in doing so.
2. Interim arrangements, including an interim standard and/or specific measures, may be appropriate if immediate implementation is not possible due to the complexities associated with evolving the frameworks. It may also be appropriate if there are issues that cannot be overcome quickly, such as market power issues. In these cases, it is considered to most likely be able to quickly deliver the benefits of the evolved framework, while minimising the extent of uncertainty and complexity associated with implementing more complex transitional mechanisms.
3. Alternate structured procurement mechanism(s), such as directed procurement by AEMO, would only be suitable (as a tranistional arrangement) where the implementation timeframe is relatively longer - around five years - and/or there are urgent system security concerns to resolve.

Based on this analysis, we consider that interim arrangements (option 2) appears to be the most promising transitional mechanism, however the Commission remains committed to implementing the evolved framework as quickly as it is effective and efficient to do so.

Several key policy decisions will be made through the TransGrid (ERC0300) rule change process in coordination with the ongoing ESB Post 2025 market design work. This will allow the Commission to provide a firmer recommendation on the time required to implement the evolved framework and associated transitional arrangements, including the policy mechanisms to be implemented to ensure a smooth transition and implementation of the evolved framework.

Transitioning from the current system strength framework to the evolved framework requires consideration of the time required for any procedures or guidelines to be developed or amended i.e. the 'implementation timeframe'. From this, the framework then needs to translated into actions by AEMO and TNSP's through the planning and economic regulation frameworks.

It is appropriate to consider the materiality of the costs associated with any delay, against the costs associated with various transitional mechanisms to implement the core elements of the evolved framework as rapidly as possible.

This Chapter explores the:

- three potential implementation timeframes given the time required to develop relevant materials
- costs and risks associated with transitioning to the evolved framework, and
- potential transitional arrangements for each timeframes given the associated costs and risks.

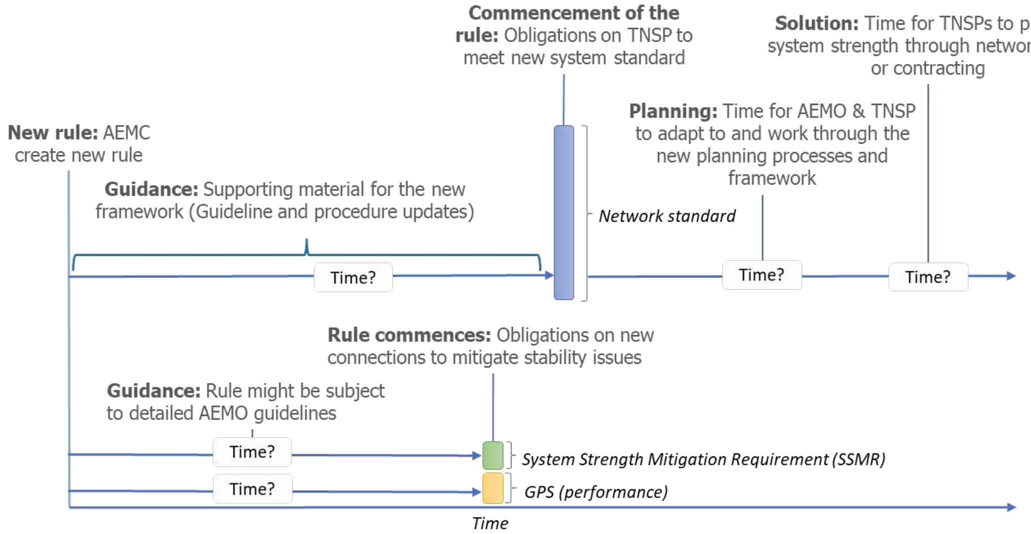
8.1 Timeframes for implementing the evolved system strength framework

The time to implement the recommended reforms requires consideration of what different elements are required to be in place before the new arrangements can fully 'go-live', and how long each element will take to develop. Figure 8.1 sets these considerations out graphically below.

Broadly speaking, these elements include:

- the development of new supporting regulatory procedures, such as guidelines or procedures developed by AEMO and the AER
- planning processes to be undertaken by AEMO and TNSPs
- economic regulatory processes to ensure that any investments made, or contracts entered into, are efficient
- physical delivery of system strength solutions by TNSPs, such as contracting processes for non-network solutions, or asset build for network solutions.

Figure 8.1: Deployment of the frameworks



Source: AEMC

This section further explores the different elements and timeframes as characterised in Figure 8.1 associated with deploying the recommended "supply side" and "demand side" reforms.

8.1.1 Supply side reforms – three different potential timeframes for implementation of a system strength standard

The Commission considers that the existing network planning and economic regulation frameworks should be leveraged to deliver the supply side reforms. This will help to reduce the need to introduce additional complexity and allow for a timely implementation of the new recommended arrangements.

To do so, the Commission recommends the introduction of a new network system strength standard, as discussed in Chapter 4. Development of this standard will include consideration of:

- how the standard should be applied
- the time required for development of supporting material
- how much time should a TNSP have in order to meet its obligations.

Application of the standard

In Chapter 4, we recommend an approach where a single standard applies universally across the entire NEM. However, the specific form of the standard is still being developed. Furthermore, the application of the standard will require specific modelling and analysis for each area, or declared node, of the network. This reflects the differing system strength requirements, on the basis of the particular characteristics of the power system.

Therefore, the specific form of the system strength standard being implemented will affect the transitional arrangements, dependent on its complexity, granularity and delegated responsibilities to market bodies and participants. The Commission is continuing to engage with all stakeholders on the exact details of the standard. This will be a key focus area in the upcoming public forum on the final report recommendations. A detailed proposal will be provided in the draft determination for the ERC0300 rule change.

Time required for development of supporting material

AEMO and the AER will likely play a central role in the implementation of the system strength standard. Each market body will be required to bring their relevant expertise to the implementation process, by developing the relevant elements of the overall regulatory framework - such as guidelines or procedures. However, each body will also require adequate time to undertake such obligations.

As presented in Figure 8.1, the relevant bodies may be required to develop guidelines and procedures, including:

- AEMO will be responsible for defining a network standard set out in the NER that appropriately reflects the local system strength requirements at specified nodes or preferred locations across the network.
- TNSPs will be responsible for working out what exactly that network standard looks like given their network.
- AEMO is likely to be responsible for producing some form of procedure or methodologies that set out the process to determine the system strength standard requirements, and location of the system strength nodes at which the system strength standard will apply. These procedures may build on the existing system strength report process.
    - The *Managing Power System Fault Levels* Rule in 2017 (Fault levels rule) provided 11 months following the publication of the final rule for AEMO to prepare a system strength requirements methodology. As such, the Commission estimate that 6-12 months would be required for these documents to be prepared following the making of any subsequent rule.
- The AER may be required to update some of its guideline documentation to better align with the recommended system strength reforms. This may include revision of the RIT-T guidelines and exemptions, and the revenue determination guidelines.

How much time should a TNSP have in order to meet its obligations?

Another key question is how much time a TNSP should be afforded in order to meet its obligations to meet a new system strength standard. This includes consideration of:

- **Planning and approval processes:** TNSPs must apply the RIT-T to proposed transmission identified needs, unless a RIT-T exemption applies. The Commission will explore whether such exemptions should apply to enable a quicker deployment of solutions to a system strength need, as part of our assessment of the rule change request.

- **Regulatory periods and cost pass through:** Consideration is required for what happens if new obligations are initiated in the middle of a TNSP's regulatory control period. Any transitional processes included in the rule in relation to the rule change request would need to consider what sort of services are included for the purposes of Chapter 6A and may need to allow for some kind of pass through, or to ensure that the new obligations are captured by the current pass through events. This would be consistent with the approach taken by the Commission in the Fault levels rule in 2017.
- **Sufficient lead time for different potential procurement options by TNSPs:** TNSPs will be able to utilise various solutions to meet their system strength obligations, including contracting with synchronous services providers to provide a non-network solution, or by themselves providing a network solution. Network solutions may require more time to implement, due to practical considerations, as opposed to non-network solutions (like contracting and retuning). As such, the time initially provided for a TNSP to procure and subsequently deploy a system strength solution should be considered, as it has implications for the range of solutions available to the TNSP to meet its obligation. This is critical; while a shorter time frame may mean that system strength solutions may be provided sooner, depending on a variety of characteristics, the TNSP may face fewer options to source this system strength. This could have cost implications for customers.[94]

On this basis, a conservative estimation of necessary lead time for a TNSP to consider the full range of system strength options (i.e. to include network and non-network solutions) would likely be three years. This includes approximately 12-18 months to undertake the RIT-T process, and 18-24 months to deploy the solution.

Possible implementation timeframes

Taking into account the considerations above, the Commission has considered three different timelines for the full implementation of the evolved framework:

- Within 18 months of the amending rule being made by the AEMC
- Within 3-4 years of the amending rule being made by the AEMC; or
- Beyond five years.

The following analysis considers the risks and costs associated with these three potential time frames for implementation of the evolved framework. In particular, we consider that the main costs and risks associated with each timeframe relate to the extent to which different sets of technical solutions to providing system strength become available. Table 8.1 presents a high-level assessment of each timeframe, in terms of the availability of network and non-network solutions.

94 Experience from South Australia can be used to better understand the timeframes required for TNSPs to effectively meet their obligations; however, we need to recognise that the situation in that market is fairly unique and so it may not be instructive for the rest of the NEM. At the time of publishing its *Economic evaluation report* in February 2019, ElectraNet estimated that commissioning the synchronous condensers would occur by end 2020 (approx. two years). ElectraNet was not required to undertake a RIT-T for implementing this solution. See: ElectraNet, Addressing the system strength gap in SA, Economic Evaluation Report, p.5, February 2019.

Table 8.1: **Possible TNSP system strength solutions compared to potential implementation timeframes**

POSSIBLE TNSP SYSTEM STRENGTH SOLUTIONS	IMPLEMENTATION TIME FRAMES		
	QUICK (18 MONTHS)	MEDIUM (3-4 YEARS)	DELAYED (5+ YEARS)
Contracting with synchronous machines	Available	Available	Available
Building synchronous condensers	Not available	Available	Available
Transmission line augmentation	Not available	Available	Available
Retuning existing inverter-based generation	Somewhat available	Available	Available
Procuring or contracting with grid-forming services[1]	Not available [2]	Not available [2]	Subject to availability

Source: AEMC

Note: [1] These solutions are marked as not available over the 3-5 year time frame on the basis that this technology is still emerging and has not yet been technically integrated into the NEM power system. [2] This is not available because grid forming service is not recognised as a service in the NEM at the moment and is not expected to be possible in 2-4 years.

As outlined in Table 8.1, a quick implementation timeframe will result in the fewest number of system strength options being available, at least in the first instance. In practice, this would most likely mean that the only option available for TNSPs in the first year would be to contract with incumbent synchronous generators. Depending on the particular market structure, this could have the potential for localised market power, which could translate to higher prices for customers, until such a time that alternative solutions become available.

Medium and delayed timeframes provide TNSPs with additional lead time and scope to consider a broader range of system strength solutions in the first instance, leading to identification of the lowest cost way to meet its obligations under a new framework. However, this may come with any costs associated with delaying the provision of additional volumes of system strength.

Consideration of these various options, and when they may be utilised by TNSPs to meet their system strength obligations, are relevant to considerations of the costs and risks associated with different implementation timeframes and processes. This is explored further in section 8.2 below.

8.1.2 Demand side reforms — implementing new system strength access standards relatively quickly

The Commission considers that the two new generator access standards for system strength discussed in Chapter 5 could be implemented within a relatively short timeframe, following publication of a final rule. The use of access standards should be a simple and effective change because it utilises the existing well-known and understood process for negotiating generator performance standards.[95] As outlined in Chapter 5, many of these standards are "AEMO advisory matters" and may require supplementary guidance material from AEMO.

Precedents exist for how quickly such standards may be deployed. For example, the AEMC amended the generator access standards and the associated negotiation framework in September 2018. The *Generator technical performance standards* final rule introduced the new access standard requirements at the time of commencement of the rule on 5 October 2018.

As part of the rule, transitional arrangements were included for projects where a connection enquiry, connection application or connection offer had been made before the commencement date of the rule. These arrangements ended in February 2019.[96] Depending on how far along an applicant was in its connection process, the transitional rules either applied the old or the new framework to the connection.[97]

In practice, this meant that only those generators who had passed the defined thresholds of agreed GPS[98] prior to 1 February 2019 were able to connect under the old access standards.

The Commission will give further consideration to the specific timing for the implementation the demand side reform, including the timing and materiality associated with the proposed changes in the rule change request.

8.1.3 System strength mitigation requirement - relatively quick implementation

The Commission notes there is a precedent for the implementation of similar reforms to the recommended evolved framework. Following the completion of the Fault levels rule,[99] which introduced the current 'do no harm' arrangements, AEMO was obligated to:[100]

- prepare and publish impact assessment guidelines within 2 months of the final rule being made; and
- publish updated assessment guidelines in July 2018 (11 months later).

The system strength mitigation requirement is recommended to be implemented through the clauses that provide for the existing 'do no harm' arrangements. As such, while not directly comparable, the implementation timeline for that reform provides some indication for a potential timeline for the system strength mitigation requirement.

The Commission therefore considers that any amendments made to this obligation on generators should not take long to deploy, given AEMO's experience to date with this requirement. We will consult with industry on these timeframes and the implementation approach through the rule change process.

95 That is it is based on the generator access standards described in schedule 5.2 of the NER.
96 The new rules did not apply to existing connection agreements unless they were later amended.
97 AEMC, National Electricity Amendment (Managing power system fault levels) Rule, September 2017, p. xvi.
98 That is, projects that had been provided a connection offer or had an executed connection agreement.
99 AEMC, *National Electricity Amendment (Managing power system fault levels) Rule*, September 2017
100 AEMC, Managing power system fault levels, Final determination, p. 73, September 2017.

8.2 The costs and risks associated with each implementation timeframe

There are several risks and costs associated with the transition from the current system strength framework to an evolved framework. As noted above, we consider that the materiality of these risks and costs is closely related to the timeframe for implementation of the evolved system strength framework.

The Commission considers the most material risk is associated with any delay in the implementation of the evolved framework, particularly the new system strength network standard. Delays in its implementation will mean that the time and cost delays that are observed under the current framework will continue to occur, impacting negatively on the outcomes that consumers experience. However, the Commission also recognises the costs that may be associated with an overly rapid implementation, particularly as this relates to the extent of solutions that are available to TNSPs to meet their obligations.

Table 8.2 presents a high-level summary of the extent to which the key risks associated with this transition are expected to be prevalent when compared with the time to deploy the framework.

Table 8.2: **Key risks and costs for each implementation timeframe**

KEY RISKS AND COSTS	IMPLEMENTATION TIME FRAME		
	QUICK (18 MONTHS)	MEDIUM (3-4 YEARS)	DELAYED (5+ YEARS)
Market intervention	Low incidence	Moderate incidence	High incidence
Investment delays	Low incidence	Moderate incidence	High incidence
Connection delays	Low incidence	High incidence	High incidence
Transient market power	High risk	Low risk	Low risk

Source: AEMC

The following section explores the nature of the risks associated with different time frames for transition to an evolved system strength framework.

8.2.1 Market interventions due to a lack of system strength

Historically AEMO have had to intervene in the market to maintain system security in South Australia due to a lack of system strength. This has required combinations of synchronous generators to be brought / remain online and constraining the output of non-synchronous generators.

Directions issued to generators in order to maintain minimum levels of system strength come at a cost to customers.[101] The evolved framework's design should mitigate the need for market intervention by AEMO. While more market interventions may be required during the transitional period to a new framework this should decrease over time as TNSPs deploy its system strength solutions. However, the extent to which this might occur depends on the specific market and system circumstances in each region; due to the very different characteristics in different regions, it is not certain that the kinds of intervention outcomes that occurred in South Australia will necessarily repeat themselves in other jurisdictions.

8.2.2 Investment delays due to uncertainty around system strength

Any uncertainty as to where the evolved framework will be providing system strength, and when those solutions may be delivered, may translate into uncertainty for new investors in IBR. Unless it is well managed, this could result in a disincentive for investment in certain parts of the network, until such time that the relevant nodes or preferred areas subject to remediation are identified.

For example, a potential connecting IBR generator may look to hold back on an investment decision, on the basis of avoiding the cost of deploying remediation measures under the existing framework, in anticipation of the project benefiting from the co-ordinated remediation efforts of the TNSP under the evolved framework. Uncertainty around the implementation of the system strength frameworks may very well be outweighed by the many other factors that affect investment decisions and can be managed by having a quick implementation timeframe, with well-known and transparent milestones.

It follows that a rapid implementation of the evolved framework would help to reduce the degree of any such investment uncertainty.

8.2.3 Connection delays due to system strength self-remediation obligations

Delaying the obligation for TNSPs to proactively provide system strength will result in generators facing either "do no harm" arrangements as they currently apply, or potentially not having to meet these obligations once the centrally provided system strength becomes available.

In either case, in the absence of a central procurement, a larger number of generators than would otherwise be the case, may therefore face remediation obligations under DNH.

Any such delays in the implementation of the new framework may result in market participants experiencing prolonged exposure to the current issues the AEMC has highlighted to date in relation to the "do no harm" requirement applying en-masse. Some generators may continue to experience time constraints on generator connections, as most TNSPs now automatically require connecting generators to undertake both the PIA and FIA process – this, along with the fact that the modelling is complex and requires new generating units to

101 Directed generators may claim compensation. The magnitude of these prices will change over time, depending on actual outcomes in the wholesale spot market. This will in turn impact on the actual price impacts felt by customers from these directions. The AEMC's interventions work program has implemented and is currently implementing changes that will minimise the costs to consumers from interventions.

be assessed in sequence, elongates the connection process. In addition to this, there is the possibility of a generator being required to undertake remediation action which takes additional time.

8.2.4 Market power issues arising from short implementation timeframes

Table 8.2 highlights that placing obligations on a TNSP under shorter implementation timeframes may result in a risk of market power issues, translating into cost impacts for customers for a period of time.

The potential for transient market power is dependent on two key factors:

1. the localised nature of system strength and
2. the time available for TNSPs to consider and implement all options to meet their system strength obligations.

Depending on the particular market circumstances, if there is a short lead time, TNSPs may not have the broadest range of procurement options available. The only option available to TNSPs in short timeframes may be to contract with existing synchronous generators. Given that TNSPs may face obligations to procure the efficient level of system strength, this could translate into TNSPs facing a regulatory obligation to procure volumes of system strength significantly above the "minimum" level needed for secure operation, within a timeframe that could materially reduce the supply options available.

This issue could be compounded by the localised nature of the supply of system strength. The ability of a system strength service to propagate from where it is provided, or be "shared" across the network, is directly related to the impedance of the power system. This means that in many instances, the supply of system strength may realistically only be provided by one local provider. This in turn means that an incumbent synchronous generator could find itself in the position where it is the only available local supplier of system strength services, and therefore may be able to charger higher prices than they would be able do under conditions of effective competition.[102]

In assessing the issues above, the Commission considers that it is necessary to strike the appropriate balance between implementing the evolved framework as rapidly as possible, while managing the associated risks. As such, we consider a medium term implementation period represents the most promising solution. Ways to achieve this balance are discussed in the next section.

8.3 Potential transitional arrangements for each timeframe

The following section explores the various transitional arrangements that might be required to mitigate the various risks associated with transitioning to a new framework. The Commission consider three separate scenarios exist for this transition.

These scenarios include deploying the framework in three ways:

102 While not all parts of the NEM will necessarily exhibit these characteristics, the decreasing availability of synchronous units (reducing supply side liquidity), coupled with the localised nature of system strength, makes this service markedly more susceptible to market power issues.

- without explicit transitional arrangements – that is, maintaining status quo until the new frameworks are fully implemented
- with transitional arrangements involving an interim system strength standard and/or temporary measures
- with transitional arrangements using an alternate structured procurement approach, which could include either AEMO contracting or Power System Security Ancillary Services (PSASS).

This section explores the extent to which these scenarios mitigate the previously identified risks associated with the transition, across three different time frames. A summary of the Commission's considerations is outlined in Table 8.3, with each option explored in more detail in the following sections.

Table 8.3: **Transitional arrangements for each implementation timeframe**

TRANSITIONAL ARRANGEMENTS	IMPLEMENTATION TIME FRAMES		
	QUICK (18-24 MONTHS)	MEDIUM (2-4 YEARS)	DELAYED (4+ YEARS)
No transitional arrangements: maintain status quo until new framework is implemented	Most preferable	Moderately preferable	Not preferable
Interim system strength standard	Moderately preferable	Most preferable	Moderately preferable
Alternate structured procurement approach – AEMO contracting or PSASS	Not preferable	Not preferable	Most preferable

Source: AEMC

8.3.1 Option 1: Status Quo (no transitional arrangements)

Under this approach, there would be no specific transitional mechanism introduced, on the basis that the full framework would be implemented in a relatively short timeframe. That is, the current arrangements (the shortfall based, minimum framework coupled with the existing DNH framework) would continue to apply, until such time as the new framework was fully implemented.

This approach of not introducing transitional arrangements would only be the preferable option if the framework could be deployed in a very short time frame, which we have defined as an 18-month period. From a theoretical perspective, such a rapid deployment is appealing, in that it would quickly ameliorate the issues that are currently being experienced in the market.

However, the Commission considers that deploying the evolved framework in such a short period is likely to be impractical. This is due to the fact that this approach is dependent on being able to rapidly develop and implement any relevant supporting regulatory frameworks, such as standards, guidelines and procedures, which would be developed by the other market bodies. Such new frameworks are likely to be critical to supporting the overall evolved framework.

Furthermore, it will take additional time for TNSPs to actually plan for and physically provide system strength solutions under the new framework.

We consider that either of these tasks may not realistically be able to be completed in a short time frame, given the technical and economic complexity likely to be associated with effectively developing these frameworks.

8.3.2 Option 2: Interim arrangements or system strength standard

The Commission recommends that an interim arrangement, specifically an interim system strength standard and/or temporary measures, could be introduced to manage the risks of transition to a new framework, for a medium term timeframe of 2 to 4 years. We consider this option offers the most measured balance of risk, against a reasonably prompt implementation of core elements of the evolved framework.

Under this transitional model, a single "interim" standard would be introduced. This standard would apply from the date of commencement of the rule, or shortly thereafter, and apply until such time as the full standard was developed and implemented. This would mean that from the date of commencement of the interim standard, TNSPs would immediately face any obligations to meet that standard, as described in Chapter 4.

An interim system strength standard would have to be relatively simple by design and straightforward to implement. This would enable the initiation of core elements of the evolved framework, while the more difficult and enduring aspects of the system strength standard are appropriately considered and designed by the relevant parties – including the AER, AEMO and TNSPs.

Such an approach would bring a number of benefits, mainly in that it would allow for the core elements of the evolved framework to be implemented in a relatively rapid manner. This would allow TNSPs to begin the process of procuring non-network solutions, or building assets, to provide needed system strength services. This would in turn support more efficient dispatch and investment outcomes.

However, this approach also brings with it a number of costs and risks. As identified above, a key risk is that under a constrained timeframe, TNSPs may have a reduced set of options to choose from, with generator contracting potentially the only solution available to meet their regulatory obligations. This may exacerbate any transient market power risks, as identified above. In this situation, TNSPs may have reduced scope to utilise their own countervailing power to address any market power being exploited by incumbent generators. This could drive up the cost of meeting their system strength obligations, potentially imposing inefficient costs on consumers and generators.

The Commission will continue to explore measures to mitigate any potential risk of transient market power in this regard. Providing TNSPs with adequate time to consider and implement the full range of solutions is likely to be central in mitigate this risk. In addition, the existing

AEMO interventions framework - including directing generators - can be used as a backstop. In addition, such options that the Commission will consider include:

1. TNSPs could be allowed to refuse to enter into contracts offered by incumbent synchronous generators, if it could be demonstrated that procurement of those contracts did not represent an efficient outcome, or good value for consumers. The AER could have a role in providing guidance as to how this decision might be made by TNSPs, and may also have a role in assessing and overseeing any such decision.
2. TNSPs could also be allowed some form of exemption from the need to undertake a RIT-T when meeting the interim standard, under specific circumstances. This would allow for a more rapid technical assessment and construction of any assets needed to meet the interim standard. There is some precedent to this under the existing minimum system strength frameworks, where TNSPs are granted an exemption from the RIT-T where a shortfall is declared by AEMO with less than 18 months before it binds.
3. Whether the charge faced by generators for system strength could be modified to be two-way i.e. where those generators that supply system strength get paid this price for the provision of system strength.

8.3.3 Option 3: Alternate structured procurement approach – AEMO procurement

Another potential interim option to manage the transitional period could be for AEMO to have a time limited role in the procurement of system strength, to "fill the gap" until such time as TNSP's could effectively step into this role.

There are a number of examples currently being considered through the ESB Post 2025 Market design work, which provide an illustration of what such a mechanism might look like. These include:

- **Power System Security Ancillary Services (PSSAS) –** this mechanism would combine inertia and other services (including system strength) into a combined "synchronous services" product.[103] Under this approach, AEMO would run a competitive day ahead auction to prompt bids from resources to provide synchronous services, instead of directing plant in instances where the projected availability of synchronous services is considered insufficient. The Commission understands that this approach to procurement would be based around short term auctions for the provision of synchronous services, and would not necessarily involve AEMO entering into long term bilateral contracts with synchronous generators. [104]
- **Bilateral forward contracts between AEMO and system strength providers** – Under this approach, AEMO would enter into multi year contracts with synchronous resources (including synchronous generators and synchronous condensers), and would be able to call on these resources to come online when needed. This would give AEMO the confidence that a sufficient volume of resources will be available to provide system strength. This mechanism would require AEMO to identify system strength requirements

103 *ESB, Post 2025 Market Design Consultation paper, p. 68, September 2020*
104 Energy Security Board, *Post 2025 Market Design Consultation Paper,* pp.62, 71, September 2020

over the relevant contracting horizon. Additionally, this mechanism would contribute to reducing the risks of prolonged market intervention for system strength.[105]

The Commission considers that there are risks with having multiple procurers (even if AEMO as procurer is phased out in favour of the TNSP) given that it may confuse the market as to who is providing system strength, and result in higher cost solutions being provided.

The Commission therefore considers that this model would only be appropriate as a transitional arrangement for longer implementation timeframes, such as those upwards five years.

8.3.4 Conclusion

The Commission considers that some form of interim arrangements, as described in option 2, appears to be the most promising option for a transition mechanism. However, we remain committed to looking to implement the evolved framework as quickly as is effective and efficient to do so, given the existing system strength issues.

An interim standard is likely to offer the most measured balance of risk with the best integration with the evolved framework.

However, there are several key policy decisions to be made regarding the evolved framework before the Commission can clearly identify the time required to implement the reforms. These include the:

- setting of the system strength standard, particularly the specific metric used,
- responsibilities of market bodies, particularly the role of AEMO and the AER,
- exact nature of the amendments to be made to the "do no harm" arrangements, and
- design of the 'who pays' element of the supply side.

These decisions will be made through the *Efficient management of system strength on the power system* rule change process and will allow the Commission to provide a firmer recommendation on the time required to implement the evolved framework and associated transitional arrangements.

105 Energy Security Board*, Post 2025 Market Design Consultation paper,* p. 70, September 2020

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
IBR	Inverter-based resource
NEL	National Electricity Law
NEO	National electricity objective
SSMR	System strength mitigation requirement
SCR	Short circuit ratio
AFL	Avaliable fault level
TNSP	Transmission network service provider
DNSP	Distribution network service provider

A FURTHER INFORMATION ON THE DESCRIPTION OF SYSTEM STRENGTH

System strength is a complex power system phenomena that is relevant to a broad variety of stakeholders to varying extents. This appendix seeks to provide a description of system strength that assists both non-technical and technical stakeholders to engage in this review.

This appendix is consequently broken into three sections that each describe system strength to different levels of detail:

- Appendix A.1 provides an overview of the basics of system strength and how it is an issue in the NEM. This is provided for those who are unfamilar with the topic and wish to understand the service at before reading this report.
- Appendix A.2 describes the Commission's evolved definition of system strength and how it relates to power system stability as a whole, expanding on the description provided in Chapter 2.
- Appendix A.3 further explores the power system concepts that constitute system strength when defined in terms of voltage waveform stability, again expanding on the concepts explored in Chapter 2.

A.1 Introduction to system strength

A Grattan Institute report[106] described system strength in lay terms as a property of the grid that "helps to prevent some shocks from becoming widespread." It goes on to state that a system's strength refers to how robust that system's voltage is to a shock.

Voltage can fall rapidly if lines clash with one another or become electrically connected to the ground, because current flows through the fault (a short circuit) rather than to customers. This is most commonly caused by lightning or wind, or when transmission towers are damaged and fall. The rapid flow of current to a fault is called 'fault current', and is used to detect faults and trigger protection mechanisms.

While the Grattan description may not be quite right, generally, system strength is the stability of a power system under all reasonably possible operating conditions. For example, a power system's ability to maintain good voltage control following a disturbance is a characteristic of a power system with a high level of system strength. Conversely, weaker systems are more likely to have voltage instability or collapse.[107]

System strength is described more technically as "the ability of the power system to maintain the voltage waveform at any given location, with and without a disturbance" by AEMO.[108] This includes resisting changes in the magnitude, phase angle, and waveshape of the

106 Grattan Institute, *Keep calm and carry on: managing electricity reliability*, February 2019, pp. 29-30.

107 AEMO, Fact Sheet System Strength, 2016, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/AEMO-Fact-Sheet-System-Strength-Final-20.pdf

108 Ibid.

voltage. When system strength is high at a connection point, the voltage changes very little when a change in load or generation occurs at the connection point.

A.1.1 How is system strength currently defined and measured?

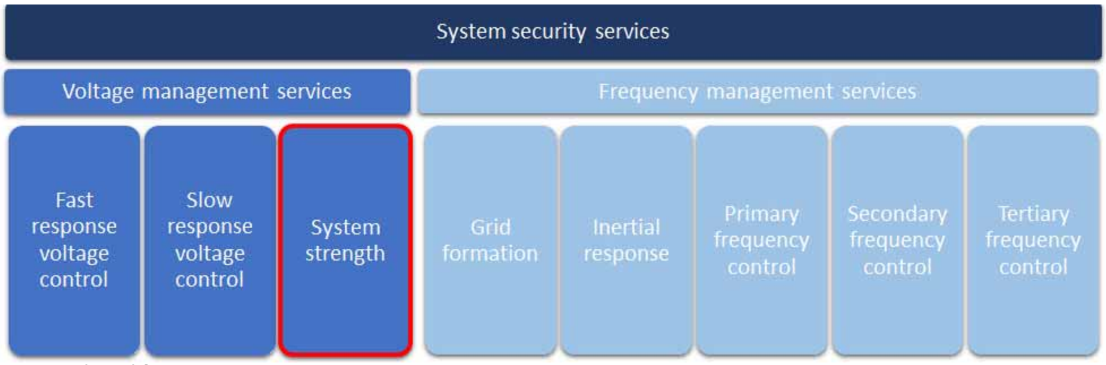
System strength is measured by the available fault current at a specific location in the power system. Stronger power systems typically have higher fault current levels as they have a greater ability to maintain the voltage waveform."[109]

This is why a *system strength service* is defined in Chapter 10 of the NER as "a service for the provision of a contribution to the three-phase fault level" at a given location in the transmission network. Appendix A.2 of this appendix explores how the Commission has developed this definition of system strength to better capture and describe the issues being experienced in the NEM.

A.1.2 How is system strength different from other system security services.

Broadly, power system security services can be categorised as relating to the management of frequency and the management of voltage as shown in the figure below. AEMO identifies system strength as an essential voltage management service.

Figure A.1: **System security services in the NEM**



Source: Adopted from AEMO, Power system requirements.

Voltage management is necessary to ensure the secure and reliable delivery of power throughout the network. It is important to prevent damage to electrical equipment, reduce transmission losses, and maintain the system's ability to withstand and prevent voltage collapse.

System strength is a service related to voltage stability, or the resistance of voltages to sudden changes, and therefore differs from other system services, such as:

- **voltage control** — which is regulated by the injection or absorption of reactive power to manage the voltage at a given point in the power system.

109 AEMO, *Maintaining power system security with high penetrations of wind and solar generation,* October 2019, p. 22.

- **frequency control** — which relates to the rotational speed (wave form) of the synchronous generators connected to the system
- **inertial response** — which refers to the inherent capacity of large spinning machines to dampen the rate of change of frequency following a contingency event that produces an imbalance in active power supply and demand.

A.1.3 How is system strength provided?

Synchronous machines (including motors and condensers) are electromagnetically coupled to the AC power system. This means that some interactions of the machine with the overall power system are dictated, and determined, by the physical characteristics of the machine. This includes responses of kinetic inertial responses to a frequency disturbance, or a reactive current response immediately after occurrence of a fault.

The main way that system strength is provided in the energy market is as a by product synchronous generators producing energy. This is the same with a number of other system security services, including inertia. Synchronous generators include those based on coal, gas and hydro technologies. Therefore, areas with high levels of system strength are typically determined by the number of synchronous generators connected in any given location or the number of transmission or distribution lines connecting generators to the rest of the network.

Synchronous condensers are another type of synchronous machines that can provide system strength into the power system. They are, for all intents and purposes, a synchronous motor/generator but differs as the rotating shaft is not connected to anything—it simply spins unimpeded (after being started by a motor). These are typically utilised by network businesses for voltage control services and have just been purchased to resolve the system strength issues in South Australia.

There are other technologies that can provide system strength, with more being developed as power system operation with high penetrations of non-synchronous generators are researched.

A.1.4 Why is less of it being provided now?

System strength has emerged as an immediate power system security need as synchronous generation beginning to retire or reduce their operation in the NEM. Additionally, as more system strength is required in the grid to assist the connection of the high levels of non-synchronous generation coming online.

Non-synchronous generation is electronically coupled to the AC power system through control systems, where many of the responses are determined by the specific settings of the control system. The result is that they will typically be a 'sink' for system strength. This means they use more system strength than they provide in aggregate. Non-synchronous generators are typically solar and wind technology-based generators.

Historically, system strength was not considered a necessary power system security service due to the prevalence of synchronous generators, the operating characteristics of which provided system strength as a matter of course.

The system strength requirements of the power system to maintain a secure and reliable grid is likely to increase given the above.[110]

A.1.5 Why do we need system strength?

Low levels of system strength can jeopardise the correct operation of generator and network protection mechanisms and the stable operation of inverter-based plant, thus impacting system security. The power system requires a level of system strength such that it:

- remains stable under normal conditions
- returns to a steady state condition following a system disturbance.

Fault currents vary across the grid both by location and voltage level. In the event of a line disturbance, voltage can fall rapidly as the current flows through the fault (short circuit).

A strong system will generate high levels of fault current in an attempt to restore the situation by responding to the drop in voltage and reducing the effect of a fault on voltage in its vicinity.[111] The higher the fault level, the higher the response strength to faults in that area.

The table below outlines a summary of the main issues associated with low system strength.

Table A.1: **Summary of main issues associated with low system strength**

ISSUE	DESCRIPTION
Non-synchronous plant stability	Non-synchronous generation that is connected to the network using power electronic converters (PECs) requires a minimum system strength to remain stable and maintain continuous uninterrupted operation. Different types of converters match their output to the frequency of the system differently while maintaining voltage levels and power flows. In a weak alternating current (AC) system, this can lead to: • Disconnections of plant following credible faults, in particular in remote parts of the network. • Adverse interactions with other non-synchronous plant (instabilities/oscillations have been observed in practice in the NEM). • Failure to provide sufficient active and reactive power support following fault clearance.
Synchronous plant stability	Low system strength can affect the ability of generators to operate correctly, resulting in disconnections of synchronous machines during credible contingencies.
Operation of	Protection equipment within power systems work to clear faults on only the

110 AEMO, System Strength Requirements Methodology, July 2018, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf

111 AEMO, Fact Sheet System Strength, 2016, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/AEMO-Fact-Sheet-System-Strength-Final-20.pdf

ISSUE	DESCRIPTION
protection equipment	effected equipment, prevent damage to network assets and mitigate risk to public safety. In weak systems: • Protection mechanisms have a higher likelihood of maloperation. • Protection mechanisms may fail to operate, resulting in uncleared faults and/or cascaded tripping of transmission elements due to eventual clearance of the fault by an out-of-zone protection resulting in excessive disconnection of transmission lines and associated generation.
Voltage management	Strong power systems exhibit better voltage control in response to small and large system disturbances. Weak systems are more susceptible to voltage instability or collapse.

Source: AEMO, Power system requirements, reference paper, p. 18, March 2018.

A.2 The Commission's evolved definition of system strength

The current NER use of three-phase fault level as a proxy for system strength does not necessarily provide a complete description of the service. As industry and power system operators have gained experience in dealing with system strength in the NEM, stakeholders have highlighted that defining system strength in terms of fault current potentially fails to describe the nuances associated with all aspects of the service. In absence of an alternative definition for system strength, the terms has consequently become a catch-all term for a suite of interrelated factors that together contribute to power system stability.

The Commission has therefore concluded that the existing regulatory definition of system strength service needs to be evolved to better reflect the true nature of what ‘system strength’ in order to better identify, understand and address the underlying power system issues that are being experienced in the NEM.

A.2.1 An overview of the Commission's evolved definition

At a high level, the system strength problem scope can broadly be defined by reference to whether the power system’s voltage waveforms are stable, under both normal and disturbance conditions, as discussed in Chapter 2. AEMO currently defines the effect of system strength as: [112]

“*the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance*.”

On this basis, the Commission has developed a working description of the *effects* of system strength on the power system, which we consider complements AEMO's definition. That is, we consider that system strength is relevant to:

112 AEMO, Renewable integration study — stage 1 report, April 2020, p.50.

The stability of voltage waveforms related to the interactions between generator equipment (synchronous or inverter-based) and the rest of the power system.

In other words, system strength is:

1. The ability of the power system, including all connected components and their interactions, to maintain voltage waveforms that remain stable, following small or large changes in terms of voltage amplitude and phase angle. Such voltage stability should allow the power system to move to a stable steady-state following transient conditions created by faults or large disturbances.
2. A quality related to the resilience of voltage waveforms to quasi-instantaneous changes. This resilience depends on:
    a. the physical qualities of mechanical power system elements, i.e. network impedance and electromagnetic responses of synchronous machines to changing voltage waveforms, or
    b. the control logic of power electronics that dictate their behaviour in response to input voltage waveforms.

System strength is not:

1. The isolated performance or behaviours of individual pieces of equipment connected to the power system.
2. Solely the provision of fault current or the presences of synchronous machines.
3. Active power control, including inertia and frequency control.
4. Reactive power control, as currently defined as a system security service.
5. Grid formation as currently understood, although there is a very large crossover with voltage waveform provision (see appendix A.3.1).

The Commission has further deconstructed system strength in terms of voltage waveform stability, as detailed in appendix A.3.

A.2.2 System strength as part of power system stability

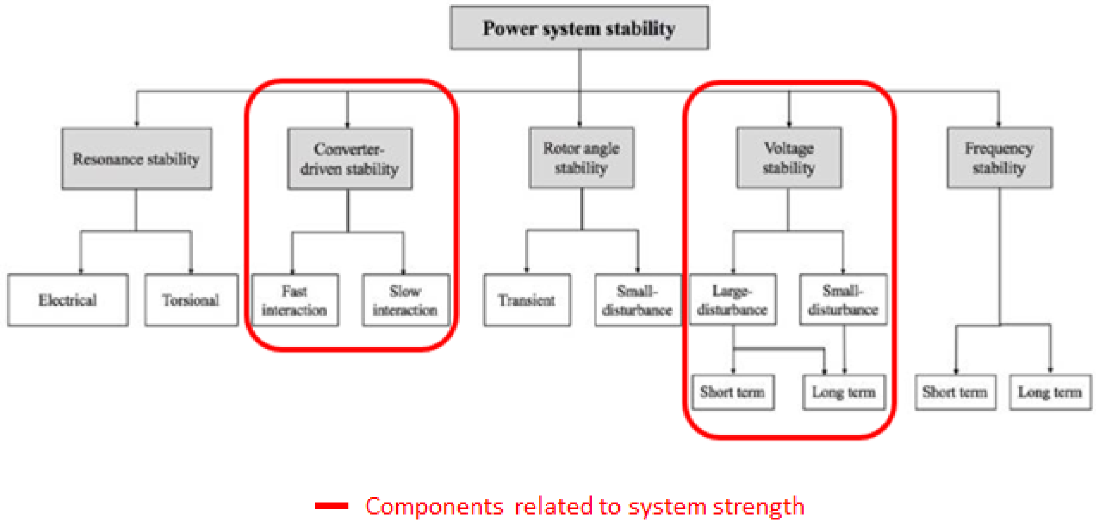
System strength forms an integral part of power system stability. CIGRE defines power system stability in terms of five key components:

1. Resonance stability
2. Converter-driven stability
3. Rotor angle stability
4. Voltage stability
5. Frequency stability

As the term 'system strength' is not an official and defined power system concept in of itself, it is not an explicit component of CIGRE's map of power system stability. Rather, the underlying power system issues experienced due to low system strength fall under the components defined by CIGRE. Through the Commission's evolved description of system strength, system strength would be classified as primarily an issue of large and small signal voltage stability and converter-driven (or inverter-driven) stability.

Figure A.2 demonstrates how system strength relates issue of power system stability as mapped by IEEE. The strength of the system is associates with the impedances of the network and therefore relates inverter-driven stability (referred to as converter-driven by the IEEE) and voltage stability. Frequency stability, rotor angle stability and resonance stability primarily relate to the stability of interactions involving electrical machines and the network.

Figure A.2: System strength as part of power system stability



Source: AEMC modified version of original graphic by CIGRE

A.2.3 Other definitions of system strength

In 2017, NERC defined electrical system strength as:[113]

"the **sensitivity of the inverter - based resource terminal voltage** to variations of its current injection. In a "strong" system, this sensitivity is low; in a "weak" system, this sensitivity is higher."

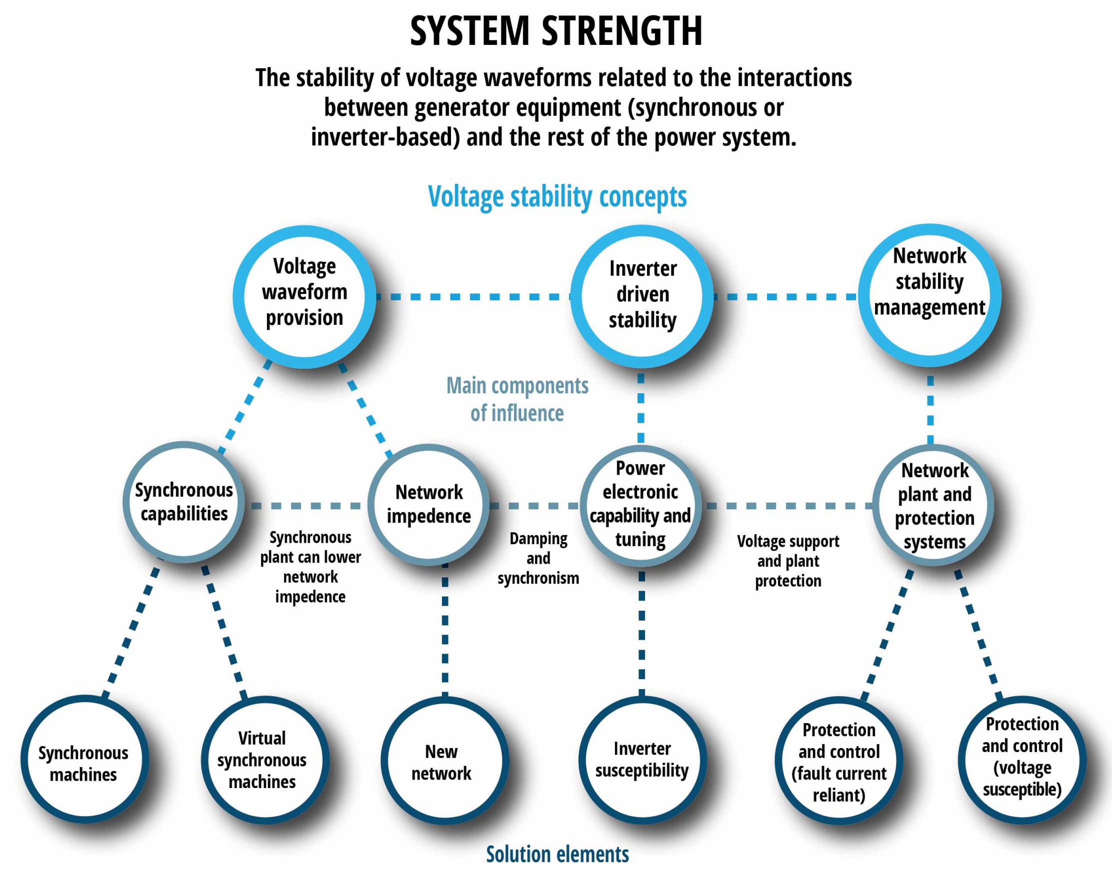
NERC's explanation of system strength captures the issues identified by the Commission to pertain to inverter driven stability. The Commission regards the sensitivity of system voltages as a key indicator of the overall stability of voltage waveforms in the power system. The Commission's description is of system strength is therefore consistent with the definition provided by NERC.

113 NERC, *Integrating Inverter Based Resources into Low Short Circuit Strength Systems,* December 2017, pg. *x*

A.3 Further detail of the Commission's description of system strength

The Commission describes system strength in terms of voltage waveform provision, as discussed in Chapter 2. This section further breaks down this description into the three key voltage stability concepts, themselves linked to a number of influencing characteristics of the power system. Many of these sub-components are interlinked and influence each other, as indicated in Figure A.3.

Figure A.3: System strength description



Source: AEMC

More detail on these three key components of voltage waveform stability is provided below.

A.3.1 Voltage waveform provision

The supply of a 'strong' and independent voltage waveform into the power system is the initial 'source' of system strength. This requires the output of a voltage waveform based on internal references, whether:

- electromechanical — like that from synchronous machines (generators and condensers)

- digital — inverters capable of operating as virtual synchronous machines, sometimes referred to as grid forming inverters. This type remains theoretical and untested in large scale power systems. However, several stakeholders, including AEMO, ARENA and TNSPs support the potential of this technology and its adoption soon.

Voltage waveform provision is similar to some interpretations of a theoretical grid-forming service for large power systems. However, grid formation often implies black start capabilities which require active power provision, neither of which is a component of system strength.

The provision of a strong voltage waveform is also dependent on the network impedance. The lower the network impedance, the further strong voltage waveforms can propagate to support the power system. The main factors that influence network impedance are the:

- presence of synchronous machines connected to the network and operating,
- extent to which the network is well-meshed with high capacity lines.

A.3.2 Inverter driven stability

This refers to the interaction between network elements and inverter control systems of IBR generation, and their ability to remain stable, when a small change (e.g. generator ramp) or large disturbance (e.g. line switch) affects the system's voltage.

On the plant side, it is the susceptibility of inverter control systems to disturbances and their resultant behaviour. In a strong system, voltage spikes or phase shifts are positively damped towards a stable steady state by both network and plant. This means:

- Steady state conditions are stable, inverter control systems do not reflect, amplify or otherwise create instabilities in response to small signals.
- Following large disturbances, power electronic control systems can remain synchronised. This includes the inverter phase lock loops (PLLs) handling the magnitude of phase shift.

On the network side, the higher the impedance of the network, the less the network would be able to damp any disturbances that are experienced or produce by IBR. The impedance of the system as seen from the inverter terminals depends on the transport (network elements) and the synchronous sources. In a remote location the system impedance is dominated by the network elements, but could be dominated by a synchronous condenser if the network or another generator has one nearby.

A.3.3 Network stability management

A certain baseline level of system strength is needed in different parts of the power system to ensure that network plant and protection systems can operate effectively. This includes both the correct operation of:

- inverter-based network plant, such as Static Var Compensators (SVCs)[114].
- network protection mechanisms that are triggered when sufficient fault current flows through the network when a fault occurs.

114 SVCs are network devices that help regulate power system voltages by providing fast acting reactive power control.

The operation of inverter-based network plant shares similar needs and considerations as that of IBR generation. The correct operation of network protection mechanisms results in a different kind of demand for system strength.

In a strong system, faults are cleared quickly and their impacts on the surrounding system are minimised. This includes the provision of fault current to operate network protection mechanisms and the sensitivity of both network and plant voltage triggered protection mechanisms.

The fault current requirement of an area of the system can be reduced through the use of protection mechanisms that require little or no fault current to activate, such as phasor measurement units (PMUs).

Appropriate fault management requires the effective operation of protection mechanisms and includes:

- Triggering the correct breakers to minimise area of the network, including generation and load, cleared. This minimises increases in network impedance and loss of generating plant as a result.
- Doing so quickly, such that the network remains synchronised.
- No triggering of protection mechanisms when they should not operate.

The failure of protection mechanisms can result in damage to connected plant and large areas of the network being cleared. The latter can cause significant change to network topology and may have cause the disconnection of system strength contributing plant, resulting in an even weaker system post-fault.

A.3.4 Interactions and links between the voltage stability concepts

The Commission recognises there are complex interactions between each voltage stability concept their sub-components. Changes in the 'strength' of each of these major components can have flow on effects on the 'strength' of other components.

For example, the connection of synchronous machines also lowers network impedance, as seen by other network connected devices.

- Lowering impedance through network build-out also decreases the volatility of voltage changes as experienced by connected plant, synchronous or inverter based. Lower impedance also has flow on effects on related qualities such as synchronous torque and reactive power provision.
- Well-tuned power electronics provide less volatile outputs into the system, meaning less voltage volatility even in high impedance networks. Well-tuned and capable inverters are also able to contribute to limiting voltage sags during fault conditions through their fault ride through modes.
- Many major network protection mechanisms rely on fault current, at levels currently only provided by synchronous machines. However, effective operation of protection mechanisms limits the area of network cleared (and hence changes in network

impedance) as well as limiting the time plant, including power electronics, are exposed to fault conditions.

B FURTHER INFORMATION ON SETTING A SYSTEM STRENGTH STANDARD

This Appendix provides more detail on the Commissions considerations for, and possible approach to, developing a system strength standard as discussed in Chapter 4. This appendix goes through each of the four elements of the system strength standard. These are the metric, level, areas and administrator.

For each of these elements, this appendix details:

1. Information on the way and options the Commission considered while developing the recommended system strength standard.
2. Further explanation and detail on the Commission's recommended approach, expanding on what is set out in Chapter 4.

B.1 Determining the metrics for the system strength standard

B.1.1 Limitations of fault level as a metric for system strength

This section provides more detail on the limitations of fault level as a metric for system strength, as the metric used as the basis for the current NER definition of a system strength service.

Fault level as a proxy is limited in its effectiveness

Measuring system strength in terms of fault current does not necessarily provide a complete description of system strength issues. As such, it can only be considered a proxy metric for the service.

The current NER system strength service definition is based on fault current.[115] This definition suggests that the provision of fault current is the most appropriate measure to considers ways to address system strength issues in the power system. However, by focusing on fault current, it may not effectively account for and allow consideration of alternative ways in which power system security and stability in low system strength environments might be maintained.

To explore the limitations of focusing solely on fault current when defining system strength issues and solutions, we have unpacked the concept of system strength to describe the specific phenomena. We have done this by reference to voltage waveform stability, which itself can be broken down into three key components:

- **Voltage waveform provision -** The supply of a 'strong' voltage waveform into the power system is the 'source' of system strength. This is the reference signal on which the system operates.
- **Inverter driven stability –** The impact of inverters on the voltage waveform. This can be conceptualised as the ‘demand’ for strong voltage waveforms. This includes the

115 Clause 5.20C.3 of the NER.

stability of inverters and their interactions with other inverters and the rest of the power system – weak systems tend to exhibit unstable interactions between inverters.

- **Network stability management –** Network plant and equipment require adequately damped voltage waveforms to operate effectively. This includes 'demand' for sufficient fault current to correctly operate protection mechanisms.

Fault current is effectively a measure of impedance and so is important for fault management. It only explicitly captures issues under network stability management. Fault current does not adequately capture inverter driven instability, because it cannot directly measure the IBR generator contributions or impacts on the stability of the voltage waveforms. As the penetration of IBR generators increase in the NEM as the generation mix transitions, the stability of inverters and their demand for voltage waveform provision are expected to become the most material system strength phenomena.

Use of fault current in definition of system strength service may preclude efficient solutions

The current arrangements require AEMO to declare a shortfall in system strength, and then for a TNSP to provide system strength services to meet the shortfall.[116] This means that the TNSP must find some way of supplying fault current (as system strength services are currently defined by reference to fault current). However, services based on the provision of fault current may not be the most effective way of managing system strength phenomena associated with interactions between IBR. In fact, this can potentially mask the adverse interactions that may occur between IBR generation, rather than address the source of these problems.

Nevertheless, solutions other than those based on provision of fault current may be used to address the underlying problems related to unstable inverter-based interactions. In particular, TNSPs can address the issue by collectively re-tuning the affected IBR generators. Instead of *supplying* more fault current (system strength) this would instead reduce the *demand* for system strength.

In contrast to the provision of additional fault current, collective retuning may represent a more efficient, lower cost solution to addressing inverter-based instabilities (although some stakeholders have noted it is unlikely to represent the whole solution). This collective retuning could be delivered as a non-network service entailing the compensation of groups of existing generation.

The Commission understands that collective retuning has been implemented in West Murray, which enabled AEMO to manually 'reset' the shortfall by reassessing and effectively reducing the minimum levels of system strength required. The Commission also understands that collective retuning is also being pursued as a mechanism to address system strength shortfalls in the QLD transmission network.[117]

116 Clause 5.20C.3 of the NER.

117 The lack of clarity in how collective retuning services may be utilised by TNSPs through the current framework is seen as a barrier to its use, even when it is the most efficient remediation option. The technical working group noted that a more structured process of how collective retuning (and its associated renumeration) could occur may require further investigation post implementation of the evolved framework .

The Commission understands that current arrangements may not effectively account for these kinds of solutions, on the basis that they refer to the provision of fault current by TNSPs to address system strength issues. Collective retuning activities do not strictly meet this definition, as they do not involve increasing the "supply" of fault current – even though they may effectively address the issue.

Other solutions to inverter-driven instability may utilise grid forming inverters, which can help to stabilise the voltage waveform by providing a reference voltage. However, it also appears that definitions of system strength based around fault level may not effectively account for this emerging technology. Incentives for the use of grid forming inverters are also being explored as part of the generator obligations, discussed in Chapter 5 and 6.

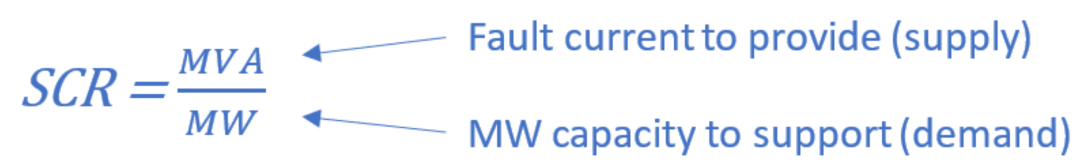
B.1.2 Other metrics that may potential options for a system strength standard

Short circuit ratio (SCR) - the basis for a system strength metric

A starting point for development of a new metric may require TNSPs to maintain a certain short-circuit ratio (SCR) at selected locations in the transmission network. SCR is the ratio of fault current (MVA) at a particular location to the IBR capacity (MW) that needs to be supported at and around that location.

Therefore, TNSPs would need to supply and maintain a fault current to a particular location at a level that is proportional to the local inverter-based generation capacity. As more generation connects around that point over time, TNSPs would be need to (proactively) increase the fault current provision in order to maintain the SCR.

Figure B.1: SCR: the ratio of supply to demand of system strength



Source: AEMC

In this way, a standard that is defined around SCR be can be seen to require TNSPs to balance the 'supply' of system strength with demand from IBR, as shown below.

To reach a certain level of SCR, the supply side (numerator) can be increased by providing more fault current. This could include increasing the number of synchronous machines in the network, or augmenting the network itself (reducing impedance).

The demand side (denominator) is dependent on the amount of inverter-based generation being taken into account. This means that the more generation that connects in an area being considered by the standard, the lower the SCR will be, if supply of fault current remains the same. Alternatively, constraining down generators by disconnecting their inverters can reduce the MW denominator of the ratio.

An SCR metric provides an indication of the voltage waveform stability of the network and the synchronous capability online by reference to available fault current. However, on its own, a basic SCR metric is still reliant on fault current as a measure for system strength, and so does not directly capture the voltage waveform impacts of IBR or the potential contribution of grid-forming inverters.

How an SCR metric evolves the regulatory definition of system strength

Voltage waveform stability can be examined in terms of the contribution or impact of its active and passive components to assess the usefulness of a metric for assessing system strength. These are:

1. The **active** portion of waveform stability is dependent on the proportion of waveform provision to waveform impact by inverter-based generation.
2. The **passive** portion of waveform stability is dependent on the impedance of the network.

A simple SCR provides a measure for the passive side of system strength, in terms of available fault current, which provides a proxy measure for impedance (the effective resistance in an AC circuit – that is, the AC circuit equivalent of resistance in a DC circuit) in the power system. The supply of fault current increases as impedance decreases, which occurs when the network is built out and when synchronous generators are connected. The lower the impedance of the network, the better changes to the voltage waveform are damped, improving voltage waveform supply and helping mitigate the impact of demand.

A simple SCR also partially (indirectly) captures most of the active 'supply' of system strength. For the purposes of system strength, only the fault current contribution of synchronous generators is taken into account. Therefore, fault current provision also correlates with voltage waveform provision from real synchronous machines.

However, metrics based solely on SCR would fail to capture some key system strength issues. These include:

- Fault current only indirectly captures voltage waveform provision. Grid-forming inverters do not inherently supply large fault currents so may be overlooked with a simple SCR metric, however they are capable of actively stabilising the voltage waveform.
- Similarly, fault current cannot measure the active impact of inverter control systems and their interactions with each other. Therefore, maintaining a 'good' SCR alone may still result in instabilities in the system (although lower impedance can help mask poor inverter performance).

Potential enhancements to the SCR metric

There is not an existing, perfect metric to capture all the phenomena associated with system strength. However, we have explored several alternative metrics that could be useful, given our evolved understanding of system strength. A summary of these options is provided in the table below.

At a high level, the metrics being explored are:

- Short circuit ratio (SCR) / Weighted SCR (WSCR): A well-established metric that measures the ratio of available fault current (MVA) to the local IBR (MW). Weighted SCR (WSCR) is a more granular variant that better accounts for the interactions of IBR. These metrics effectively measure network impedances, and so capture only the passive portion of system strength.
- 'Equivalent SCR': A theoretical variant of SCR that measures available fault current as a ratio of the system strength impact of local IBR, measured in 'equivalent MW'. This metric tries to better account for the active stability of inverters and their control system interactions than the conventional SCR variations, by adjusting the MW denominator of the SCR equation.
- Voltage stability criteria: A set of outcome-based criteria that provide a TNSP with specific targets for voltage stability in the network. These can be developed to target specific power system stability goals.
- System strength objective: A more general outcome objective or set of objectives for TNSPs to meet, e.g. to support the connection and stable operation of a certain amount of MW of IBR. TNSPs would be able to meet these general objectives through whatever technical solution they see appropriate for the situation at hand.

Table B.1: Potential system strength metrics

	SCR/WSCR	'Equivalent SCR'	Voltage stability criteria	General objective
Potential system strength metrics	A simple short-circuit ratio (SCR) is the ratio of available fault current in the network to the MW capacity of a plant, measured at the connection point. Variants such as weighted SCR (WSCR) attempt to provide an 'average' measurement of fault level availability to connected plant over wide areas, taking into account multiple busses and multiple inverter-based plant.	An SCR metric where the 'equivalent' MW capacity of each relevant generator can be modified by a factor to reflect their 'active' impact. E.g. A well-tuned 100MW IBR may be equivalent to a standard 80MW plant. TNSPs could meet the SCR by increasing the numerator (MVA: synchronous machines and network impedance) or decreasing the denominator (equivalent MW: capable and well-tuned inverters)	Can define a more 'outcome based' set of performance criteria for system strength. E.g. Setting limits on voltage rate of change, phase angle shifts and damping times.	Another 'outcomes based' metric would just be to require TNSPs to meet an end goal objective for system strength provision. TNSPs could then determine themselves what to measure and test. E.g. Host *X* MW of IBR in a certain area.
Pros	• Relatively simple to model and use • Captures 'passive' system strength • WSCR takes better account of interactions between	• Could capture both active and passive components of system strength • Straightforward to implement through a standard by setting an SCR target.	• Outcome focused means should capture both active and passive system strength. • Could be highly specified • Maybe useful in combination with other metrics	• Outcome focused means should capture both active and passive system strength.

Cons	• Mostly an indicative measure of impedance via fault current and may not capture or enable all possible solutions to address the 'active' components of system strength, such as collective generator retuning processes, and virtual synchronous machines as solutions) • May not adequately predict inverter instability	• Unknown how an 'equivalent SCR' could be calculated. • May not adequately predict inverter instability	• May be hard to forecast, and so may make the model inaccurate or reactive	• May not be flexible to changes in capacity investment • Vague - May not well specify what TNSPs are to supply • Vague - May not be limited to fixing system strength issues

CIGRE[118] and NERC[119] together have explored variations on the basic SCR metric that could prove to more comprehensively capture the voltage waveform stability issues that underpin system strength (these being voltage waveform provision, inverter driven stability and network stability management, as described above). These variations include:

- Weighted SCR
- Composite SCR
- SCR with interaction factors.

Another promising metric may be a form of 'equivalent SCR', which would modify the MW capacity considered – dependent on the extent of its impact.

Figure B.2: Equivalent SCR: Recognising active system strength

$$SCR_{eq} = \frac{MVA}{(MW * x)}$$

Fault current to provide (supply)

'Equivalent' MW capacity to support (demand)

Source: AEMC

Under this metric, TNSPs would be able to meet the target SCR by supplying more fault current to increase the numerator or reduce the impact of inverter-based generation to decrease the denominator. This would include an "x" factor, that could reflect the capabilities of different inverters. Solutions to improve the active system strength of the system could equally be reflected as increasing equivalent supply on the numerator.

Developing an appropriate 'equivalent SCR' would evolve the definition of system strength away from just three-phase fault level to encompass both the supply and demand of system strength. An appropriate 'equivalent SCR' metric should reflect the all types of contributions and impacts to voltage waveform stability.

Each SCR variant provides different ways to produce a single number that takes into account the different fault levels experienced by multiple plant at different connection points in the local power system. The general benefit of these SCR variants is that they better account for the interactions between IBR. Conversely, a basic SCR looks at each generator in isolation.

While these variants provide a better indication of system strength that the basic SCR described above, they are still reliant on fault current and are limited in their ability to capture the 'active' components of system strength. The Commission is exploring how other jurisdictions may be implementing SCR and its variants to measure system strength.

Through consultation with AEMO and the technical working group, the Commission considers that no one metric would likely capture all issues and solutions related to voltage waveform

118 CIGRE, WG B4.62, *Connection of Wind Farms to Weak AC Networks*, December 2016

119 NERC, *Integrating inverter based resources into low short circuit strength systems*, December 2017.

stability, and that there are trade-offs between the different metrics. Instead, some combination of metrics and criteria would likely be needed for a standard to comprehensively capture system all strength issues experienced in the NEM. The Commission therefore recommends system strength is measured by way of a hybrid 'outcomes-based' standard comprised of more than one metric.

B.1.3 Further detail on the recommended approach to the metric

The Commission recommends a standard that uses a combination of an SCR metric - specifically available fault current (AFL) - accompanied by criteria for the stable operation of IBR. This would proxy the efficient level, by reducing the probability that system strength constraints occur on existing or forecast connections, with the resultant benefits that this brings for consumers.

The existing minimum system strength uses AFL as the basis of its analysis to determine minimum fault level requirements. The Commission is proposing a modified and augmented AFL metric for the standard that more comprehensively captures the current and forecast demand of IBR.

BOX 10: EVOLVING THE USE OF AVAILABLE FAULT LEVEL (AFL) AS A METRIC FOR SYSTEM STRENGTH

AFL as a metric for system strength is used in the existing minimum system strength framework to determine minimum levels of system strength. AFL is an SCR and fault level based metric and so does not capture all aspects of system strength by itself. Further, the current application of AFL to measure system strength does not provide a holistic, forward-looking indication of system strength needs in the NEM, resulting in reactive and inefficient provision of the service.

However, the Commission has found that AFL can be evolved and augmented to address these issues to form a metric with high potential for the system strength planning standard. The key differences of the recommended AFL approach to that currently used are:

1. The proposed AFL metric would be augmented by an IBR generation stability criteria, so that the standard can better account for the active components of system strength.
2. The calculation of AFL would go further than just considering the requirements of the existing system to include forecast IBR generation to proactively provide system strength to support future connections.
3. To facilitate greater certainty in the proactive provision of system strength, the AFL calculation would be simpler as only the fault level contribution from TNSP procured service providers, whether network or non-network, would be taken into account when calculating and forecasting AFL. The 'typical dispatch' of synchronous generators in the energy market would not be part of the proposed AFL analysis.

The Commission considers that AFL is an appropriate metric to use at the basis for a system strength planning standard because:

- it can be applied in the same way across the power system, avoiding regulatory and modelling complexity
- its is simple to calculate and so well-suited to forecasting IBR and proactively meeting demand
- TNSPs and AEMO are familiar with the metric, streamlining the development and implementation of the standard.

AFL provides an indication of the balance of system strength 'supply and demand'. Therefore, maintaining a positive AFL (that is, an AFL greater than zero) can be used as a constant and universal target for system strength, which will reflect the different amounts of system strength supply needed in different parts of the NEM (dependent on the level of IBR development and network requirements in different areas). This makes AFL a practical metric, as it does not require a different target to be set for each area of the NEM, or for the target to have to be reassessed as the demand in an area changes over time.

TNSPs would be required to calculate and forecast AFL in the areas of the NEM where the standard applies. Calculating AFL is a relatively simple modelling exercise that does not require complex EMT studies. This means it is well suited to forecasting system strength as the forecasts can be easily run for different planning scenarios and can be easily readjusted and the real development of the NEM changes. AFL is therefore well-suited to a proactive planning approach to system strength.

AEMO, in collaboration with TNSPs, currently use a form of AFL analysis to determine the minimum fault level requirements at system strength nodes under the existing minimum system strength framework. They are therefore familiar with the processes and modelling that is required, reducing the regulatory and procedural changes that would be required to implement the system strength standard. The Commission is proposing that the current AEMO system strength requirements methodology is expanded for the system strength standard to better facilitate proactive and efficient investment in system strength.

BOX 11: METRICS: BENEFITS OF THE RECOMMENDED APPROACH

The key strengths of using Available fault level, augmented by an IBR stability criteria, as the basis of the metric for the standard are that it is:

- Comprehensive: By using these together, the standard can allow TNSPs to address all types of system strength issues and pursue all potential solutions.
- Simple to use: AFL is simple to calculate and forecast, and so is well suited to facilitating proactive system strength investment through a planning standard. TNSPs and AEMO are already familiar with the use of AFL as a system strength metric.

- Flexible to apply: The metric can be universally applied across the NEM, avoiding the need for determining different targets in different areas of the NEM every time the development of the power system changes or diverges from what is expected.

What is AFL

Available fault level (AFL) is an SCR and fault level based metric that provides a proxy measure for system strength in terms of the balance of supply and demand for the service. AFL measures system strength through the proportion of supplied fault level to demand of IBR, based on their minimum SCR capability.

AFL is a measure of the amount of fault level leftover or 'available' from total supply once you have allocated each IBR connection enough fault level so that it is expected to operate stably. The amount of fault level each connected IBR is allocated is determined by its minimum SCR capability. That is, the minimum amount of fault level the IBR should need for its capacity to operate without stability issues.

A positive amount of available fault current gives a good indication by proxy of that the area of the power system is 'strong' and therefore should not experience system strength issues. A negative AFL would indicate that detailed modelling is required to determine if voltage instabilities may occur (but does not necessarily mean they will occur).

BOX 12: EXAMPLE: DETERMINING AVAILABLE FAULT CURRENT

An area of the power system may have a couple of synchronous machines connected supplying 1000MVA of fault level. If the area also contains two 100MW IBR generation each with a minimum SCR of 3, the available fault current of the area would be calculated by allocating 300MVA to each generator,[1] leaving 400MVA remaining 'available'. In reality, the electrical distances between the IBR and the synchronous machines result in 'losses' in the supply of fault level, making the AFL somewhat less than 400MVA.

This available fault level indicates that at least one more 100MW IBR generator with a minimum SCR of 3 should be able to connect without any plant experiencing system strength issues.

Note: [1] SCR of 3 means for every 1MW of plant capacity, the plant needs 3 MVA. That is 300MVA for a 100MW plant.

Similarly, AFL of an area can be forecast by projecting where and amount of IBR may connect. AEMO's ISP and TNSPs' information on upcoming generation connections would be sufficient to facilitate the forecast of AFL. Forecasting AFL would also require an assumption of the minimum SCR of projected IBR connections. This assumption could mirror the minimum SCR requirement in the recommended access standard.

Limitations of AFL

The two key issues of an AFL based metric is that it is a conservative indication of system strength and, separately, may not capture all system strength issues.

The simplicity of AFL modelling may come at the cost of some accuracy, resulting in a more conservative approach to system strength supply. As noted above, having no or negative AFL does not necessarily mean that system strength issues will occur, only that detailed modelling will have to be carried out to confirm if any issues are likely to arise. However, the asymmetry of risks discussed in section XX lends support to a more conservative approach to system strength supply where it facilitates proactive investment.

AFL is an SCR based metric that relies on fault level as a proxy for system strength. Therefore, while providing a good indication of passive system strength, AFL does not capture the active interactions of inverter control systems and their potential impacts on system strength. This has two consequences:

1. System strength issues may arise even when AFL is positive due to IBR interactions amplifying disturbances
2. The potential benefits of collective generator retuning or virtual synchronous machines would not be well recognised by a traditional AFL metric.

To address these issues, the AFL metric can be augmented by an IBR stability criteria so that the standard can more comprehensively capture system strength.

Supporting criteria - IBR (inverter driven) stability

To meet the planning standard, the Commission recommends the TNSP also have a general objective or criteria to ensure that generation in the system can connect and operate stably. This criteria would augment the AFL metric to allow the standard to capture, and therefore allow TNSPs to address, the active components of system strength. In practice, this criteria would benefit the scenario in three circumstances:

1. The criteria would obligate TNSPs to identify and address system strength issues that may occur even if AFL is positive. This circumstance is likely to be rare, as AFL takes into account the fault level requirements of each individual IBR generator, it provides a relatively granular indication of passive system strength. Therefore, supplying a high level of passive system strength through positive AFL is likely to ameliorate most issues relating to the interaction of inverter controls.
2. This criteria would take precedence when AFL is negative but the TNSP can demonstrate, through the appropriate studies, that system strength is sufficient for the accounted for IBR to operate stably.
3. Allows TNSPs to pursue demand side solutions to meet the standard when AFL is negative and system strength issues have been identified. This includes collective generator retuning and virtual synchronous machines (grid forming inverters).

In circumstances two and three, the criteria would require a 'recalibration' of the AFL metric such that it is once again positive in a way that reflects that the supply and demand for system strength is balanced, even though no extra fault level may have been supplied. This would involve the TNSP performing studies to determine how much negative the AFL could be before system strength issues occur. This negative AFL amount could then be added to the AFL planning calculations as a positive amount of 'equivalent fault level', reflecting the extra strength of the system that AFL would not otherwise capture. This would give the AFL metric the strengths of an 'equivalent SCR' based metric.

The inverter-driven stability metric on its own would likely be ambiguous and involve complex modelling making it unsuitable for long term planning processes.

Other criteria for system strength

When providing system strength, TNSPs must also consider their other relevant system stability requirements in addition to the criteria for the system strength standard recommended above. Two key additional criteria separate to the standard that would relate to the TNSP's provision of system strength are:

1. Voltage step change limits - Steady state voltage change due to reactive power plant switching is limited to the requirements set out in Australian Standard AS/NZS 61000.3.7:2001.
2. Correct protection operation: The minimum three-phase fault levels provided must allow the TNSPs to maintain correct operation of protection systems.

These criteria are necessary for maintaining minimum levels of system strength across the NEM needed to keep the system secure and relate to the key drivers of system strength demand (network stability management), including in areas where there is little or no new generation penetration.

These criteria are currently included in the current minimum system strength framework as part of determining the minimum fault level requirements of the power system.[120] The recommended standard would capture the minimum requirements of the system in the AFL analysis, as is currently done under the existing arrangements.

B.2 Determining the level of the system strength standard

B.2.1 Background for determining the level of the standard

This section provides more detail on:

- what the efficient level of system strength provided through a system strength planning standard may be
- what settings of the standard will influence this 'efficient level'
- how resilience is being considered by the Commission.

Efficient level of system strength

The standard would require TNSPs to be responsible for a “total level”, or an “efficient level”, of system strength at defined locations in the transmission network. This efficient level reflects the level of system strength that provides the largest net market benefits, reflecting:

120 AEMO, *System strength requirements methodology,* July 2018, pg. 16

- The *minimum* level required for secure system operation
- Plus an *efficient* amount of system strength, which we consider can generally be defined as that amount necessary to alleviate constraints and facilitate the connection and operation of inverter-based plant, where this is efficient.

The Commission considers that the connection and operation of generators that connect in the parts of the network where system strength has been provided on a proactive basis should have increased certainty that their output will be likely to be curtailed due to a lack of available system strength, and that as a consequence, generator's should not need to undertake incremental additional investment to remediate its harm (as the SSMR requirements are unlikely to bind where the generator connects).

With an SCR metric, TNSPs would be required to supply as much fault current as needed to support the expected connected MWs of inverter-based capacity in the area around where the SCR is measured (e.g. a node in the network) as identified by the ISP as being the efficient 'amount' of connections – subject to the description above of what is an efficient outcome in terms of expected generator dispatch.

In this way, the amount of system strength required to be provided by the TNSP would be expected to change over time, as the amount of forecast MWs of inverter-based connections changes. As per current arrangements, TNSPs would provide information on their connection enquiries to AEMO to be used in this process.

Efficiency of settings

In line with the existing access arrangements, the system strength standard will not change the fact that generators have no right to be dispatched. As indicated above, the standard is based on providing an efficient level of system strength, considering the costs of providing system strength and the benefits from having more system strength in the system.

Naturally, there is a trade-off between these two elements. Several settings of the standard need to be further worked through with GHD, AEMO and the technicla working group including:

- Whether the standard is deterministic (set to a level all of the time) or probabilistic (e.g. TNSPs must meet the standard for 98% of the time)
- To what extent credible contingencies and protected events are dealt with (e.g. TNSPs must meet the standard for N or N-1 conditions)
- What else TNSPs have to take into account e.g. planning and operational uncertainties

While the Commission has identified some possible settings for the standard below, the details will continue to be examined as part of the TransGrid rule change.

Consideration of resilience

In the system strength discussion paper, the AEMC identified resilience as a component of system strength that evolved system strength frameworks should likely address.

The Commission sees system resilience as a broader power system issue to be approached by AEMO and other market bodies through multiple processes, such as the power system frequency risk review. As such, we are not proposing that resilience buffers should be explicitly included in the calculation and application of a system strength standard.

However, while we are not explicitly accounting for resilience in setting the level of the standard, the proactive nature of the network coordinated model should inherently provide an additional buffer of system strength that benefits system resilience.

Procuring system strength services ahead of the time that they are needed would likely result in levels of system strength in the power system being one step higher than they technically need to be to support system security at any given moment. This is necessary to ensure the planning standard can be met and shortfalls do not occur. This 'extra' system strength has value in that it does provide resilience of the system to unexpected events that change the system strength needs in an area of the NEM.

The value of resilience afforded by proactive procurement of system strength is a factor that influences the asymmetry of risks when considering the trade-offs between early or late procurement of system strength, which is a key factor that informed the Commission' decision to adopt the proactive, top down approach described in this paper.

B.2.2 Further detail on the recommended approach to the level

The Commission suggests the level of the standard could be set at maintaining a positive AFL (greater than zero) for specific operating conditions for a certain amount of generation determined by AEMO. This would be a deterministic standard that applies at locations determined by AEMO, as discussed further in appendix B.3.

BOX 13: LEVEL: BENEFITS OF THE RECOMMENDED APPROACH

The key strengths of setting the level of the standard at AFL>0 for select operating conditions are:

- Facilitates proactive investment - Maintaining positive AFL to a deterministic level sets a simple target that triggers the need for TNSP investment before real power system issues arise.
- More efficient than current arrangements - TNSPs would take advantage of economies of scope and scale to supply system strength that would otherwise be provided incrementally and inefficiently by individual generators as they connect.
- Flexible as the power system changes over time - The underlying amount of generation to be supported under the standard would be adjusted on a regular basis and forecast assumptions change and real IBR investment occurs.

How much system strength is provided by the standard

A positive AFL gives a good indication that the power system and any connected generation can operate stably. Maintaining a positive AFL would therefore mean that TNSPs would supply a level of system strength that allows all connected and connecting generation that is planned for under the standard would have high confidence they could operate unconstrained for system strength under normal operating conditions.

This also includes maintaining the minimum levels of system strength required for network stability in locations where there is little or no IBR generation. For example, near load centres and remote parts of the grid.

TNSPs would be obligated by the standard to procure the total amount of fault level required to maintain a positive AFL. This means that AFL calculations would not include the 'typical' dispatch of generators, only the amount of fault level otherwise provided by TNSP network and non-network solutions. This avoids the complexity of forecasting typical dispatch, which the AEMC understands cannot be done accurately more than a couple of years ahead.

Maintaining positive AFL as the efficient level of system strength

The efficient level of system strength provided by TNSPs to meet the standard needs to balance the benefits of having more system strength in the system (and so having more lower cost generation able to connect and be dispatched), against the cost of supply.

At a certain point, providing a higher level of system strength to enable more lower cost generation to connect and to be dispatched such that it would not be constrained due to system strength in rare operating conditions would have a marginal return. The cost of supplying this level of system strength may be more than the value it provides generators and consumers by avoiding constraints.

If the standard results in TNSPs providing too little system strength, then generation that would negatively impact on system strength if they were dispatched may be subject to material system strength limits on their operation. Therefore, they may not want to risk relying on the TNSP for system strength to support the operation of their plant and would instead turn to individual, private investment to better avoid constraints. This behaviour would undermine the value of TNSP investment in system strength as:

- generation investment may double up on the TNSP investment, creating an oversupply of system strength
- high probability of individual investment would increase the complexity of forecasting and planning for the future needs, as well as increasing operational complexity if more individual investments are made.

The eventualities of a level of system strength that is too low would materially blunt the locational signals and cost efficiencies of a TNSP planning standard.

The Commission therefore considers the cost-efficient level of system strength to be maintaining positive AFL to prevent the occurrence of individual remediation i.e. in areas where the economies of scale of TNSP investment would prove beneficial. This would include areas where supporting generation could be cooptimised with supporting system security levels of system strength or the provision of other network provided system services (economies of scope).

Amount of generation supported by the standard

AEMO would determine what capacity of generation should be accounted for when forecasting AFL. AEMO would therefore be determining the 'demand' that TNSPs need to supply for in order to maintain a positive AFL.

AEMO would use ISP projections of generation development, and the connection information from TNSPs, to determine an outlook on how much generation is projected to connect where. AEMO can then identify what amount of generation is likely to connect sufficiently proximate to each other that it would be efficient for the TNSP to supply system strength to support their connection and operation.

The amount of generation AEMO identifies should be captured by the standard may also be informed by other power transfer limits in the power system. For example, AEMO may find that 1000MW of generation is projected to connect in an area of the power system where a key line has a thermal limit of 500MW. In this case, AEMO would not likely find it efficient to have the standard apply to all 1000MW of projected development.

How supply of system strength would change over time

AEMO will continue to reassess the existing and projected connection of IBR generation to establish how much generation TNSPs must plan for to meet the standard over time. As AFL is a measurement of the balance of system strength supply and the demand of generation, maintaining a positive AFL will require TNSPs to continue to invest in system strength supply and support generation as more connects to the NEM.

Settings for a deterministic standard

The supply of system strength can change when events on the system occur, such a synchronous machine tripping off or a major line switching out. The level of system strength required by the standard is therefore also dependent on the extent of operational conditions that the standard accounts for.

The Commission suggests that the standard is deterministic and requires TNSPs to maintain positive AFL for select operating conditions. Such operating conditions may be expressed in terms of N or N-1 conditions. This would determine the extent to which the supply of system strength accounts for credible contingencies.

Clause 4.3.1 of the NER sets out AEMO's responsibilities for maintaining power system security, and the factors they need to consider in setting the technical envelope. One of these factors is keeping the power system at a level of N - 1 secure. Therefore, the Commission considers that N-1 conditions may be a good starting point on which to develop the standard.

However, the efficient level of system strength provided by the standard may be lower, or may be different in different areas of the NEM. For example, it may not be cost efficient to procure another system strength providing asset to provide contingency redundancy when the counterfactual is relatively minor constraint of generation when the contingency occurs. In this case, setting the standard for only for N conditions may be more appropriate. The detail of the operating condition for which the standard will apply will be determined through further consultation in the TransGrid rule change.

At deterministic approach is currently preferred over a probabilistic standard to facilitate effective planning and proactive investment - although it would compromise slightly in terms of efficiency outcomes. A probabilistic standard for system strength would require complex scenario analysis using EMT modelling and forecasting for the TNSP to assess if it is meeting the standard. Such modelling becomes increasingly intensive the further ahead the forecast goes, making it impractical for a long-term planning standard.

A deterministic standard is defined in terms of normal operation and the extent of outages that might need to be accounted for. This is more readily defined than a probabilistic approach, providing clearer investment triggers for TNSPs and, in turn, clarifying to IBR develops as to what conditions IBR generation is expected to be supported for system strength. The rigid nature of the deterministic standard means that it is not flexible to changing conditions.

The recommended level of contingency redundancy should aim to strike an efficient balance between maximising the benefits that consumers get from the dispatch of generation, against the costs and redundancy in supply required by the standard.

B.3 Determining the area where the system strength standard should apply

B.3.1 Comparing a nodal and zonal approach to a system strength standard

This section provides more detail on the differences between a nodal and zonal approach for a system strength standard.

The physics that dictate how system strength, and system strength impacts, propagate through the network is complex. It is therefore hard to draw definitive lines on the map to indicate the "boundaries" between where system strength is being provided (and where generators should connect) and other areas – that is, it is hard to define the boundaries of the areas where TNSPs have provided system strength, and where generators can be expected to locate.

In consideration of these difficulties, we are considering two general approaches to defining these areas – either a "nodal" or "zonal" system.

A nodal approach would result in the standard applying at system strength nodes, supporting nearby generation. The more electrically distant IBR generators are from the node, the more system strength would be required by the standard at the node to support it. AEMO and TNSPs are familiar with this approach as it is used in the current system strength frameworks. A nodal approach would require the addition of some limitation to how remote a projected IBR connection can be from a node before it is not planned for at the node (and is therefore not supported by TNSP investment). Under a nodal approach, passing a preliminary impact assessment at a potential connection point would indicate that that location is efficiently close to the node.

A zonal approach would involve drawing an administrative line around a selection of lines, node cluster or geographical area, inside which projected connections would be supported. A zonal approach would provide a clear locational signal, on the basis that the new generation is either inside or outside the TNSP supported area. However, this could lead to perverse outcomes, as generators may find it cheapest to connect just outside the zone, where they would not have to pay a connection fee yet may only need minor, inexpensive remediation, due to the overflow system strength from inside the node. There may also be no clear signals of where to locate within the zone - a zone would treat every connection within it as equal.

These approaches and their advantages and drawbacks are summarised below.

Table B.2: Comparison of nodal and zonal approaches

Option	Advantages	Drawbacks
System strength zones - An administrative boundary is defined around the system strength node in which generators would be supported. This boundary may be geographical, a selection of possible existing transmission assets to connect into, or some other transparent delineation.	• Clear location signals. • Simple split of responsibility between TNSP and generators.	• Difficult to delineate. • Complexities in addressing free rider issues. • Generators of varying impact treated equally within the zone.
System strength nodes - The TNSP only indicates the system strength provided at a specific node. Generators would increasingly risk needing to meet extra connection requirements to mitigate their impact the further away from the node they connect based on the results of their preliminary impact assessment.	• Each generator assessed on the amount of planned system strength available to it based on its impact. • Natural gradient from node to periphery of system.	• Locational signals much less clear • May result in more incremental investment in grey area between immediate vicinity of node and edge of grid.

The Commission's consultation with the technical working group highlighted that a nodal approach, like that used in the existing arrangements, represents the best option to define the areas where the network will face an obligation to meet the system strength standard.

B.3.2 Further detail on the recommended approach to the area

The Commission suggests a nodal approach to the standard. The standard would apply at nodes where TNSP investment would be efficient, as transparently determined by AEMO and TNSPs. This would include identifying nodes near dense forecast IBR development, and where minimum levels of system strength must be maintained for network stability such as near load centres.

BOX 14: AREA: BENEFITS OF THE RECOMMENDED APPROACH

The key strengths of a nodal approach to the standard are:

- Simple to implement - A nodal approach is simpler to implement than a zonal approach as it avoids the need to draw administrative boundaries.
- Matches the metric - A nodal approach is more compatible with how AFL is calculated than a zonal approach. It is also familiar to AEMO and TNSPs as the approach currently used for the minimum framework.
- More granular locational signals than a zonal approach - The extent system strength is supported by the TNSP investment to meet the standard will be determined by their specific connection location and set up, as tested through the simple PIA process.

Nodal approach to the standard

The Commission recommends that standard should apply at nodes determined by AEMO. AEMO would identify a node based on an assessment of the potential benefits of the planning standard applying at the node in terms of the economies of scale that may be achieved in meeting the system strength needs of the area through TNSP investment.

AEMO would therefore locate nodes where it projects a sufficient density of development through the ISP and connection information provided to it by TNSPs. AEMO would also take into account the system strength needs of the network itself, including load centres and areas remote from system strength supply.

TNSPs would be required to maintain a positive AFL at the nodes identified by AEMO. As discussed in appendix B.1.3, the TNSP's forecast of AFL would take into account the amount of generation projected by AEMO to connect around the node. A nodal approach is more compatible with the way AFL is calculated than a zonal model.

In practice, this does not require that fault level is supplied to the node itself. The node is simply a practical reference point at which to measure whether the standard is being met. Due to the locational nature of system strength, its provision is more effective if the supply of system strength is close to the demand for the service. The AFL approach allows TNSPs to build an asset or contract with a system strength provider that is distanced from the node but located nearer to the forecast generation connecting around the node where it is more efficient to do so.

A nodal approach could use groups of nodes where the standard may integrate with concept of renewable energy zones (REZs).

Locational signals for connecting IBR generation from the standard

TNSPs invest in system strength supply to meet the standard based on the location of projected generator connections. When actual IBR seeks to connect, it needs to have signals as to where it is best to so that it can take advantage of TNSP supplied system strength - or conversely, if it is supplying system strength to locate in a region where there may be little system strength. Moreover, the generation should be sent locational signals to connect where it uses the TNSP supplied system strength most efficiently.

Under a nodal approach, the more electrically distant an IBR generation connects from the node, the less likely that the system strength supplied at the node will 'reach' the IBR. Conversely, the closer IBR generation connects to the node, the more likely it is that their system strength needs would be fully supported by the TNSP investment.

TNSPs would publish their AFL projections at each node and other relevant information to allow generation to conduct their own PIAs. This would help send transparent locational signals by providing developers with the capabilities to assess the availability of TNSP supplied system strength at any location, or where there may be opportunities for it to supply system strength.

This concept is discussed further in Chapter 6 of the report.

B.4 Determining who should administrate the standard

The system strength standard needs to be set out in the NER, potentially supported by other documentation from the AER, AEMO, Reliability Panel. The section sets out further detail on the Commission's recommended approach, being that the standard is set out in the NER.

B.4.1 Further detail on the recommended approach to setting and reviewing

The Commission recommends that the standard could be set out in the NER. The AEMC would be responsible for reviewing the standard regularly and would require rule change requests to make changes to the settings of the standard.

BOX 15: ADMINISTRATOR: BENEFITS OF THE RECOMMENDED APPROACH

The key strengths of housing the settings of the standard in the NER to be administrated by the AEMC is transparency. Settings detailed in the NER must be clearly defined and publicly available, as do any AEMC review or rule change processes. NER-based standards can be inflexible and require comprehensive rule change processes to modify the settings. However, the benefit of a NER-based standard is increased certainty that the settings of the standard will not change without sufficient warning, which should help mitigate regulatory risk for IBR developers. It is also important to provide a level of certainty for TNSPs who will be making investment decisions based on the meeting the standard and forecasting their expenditure requirements to meet the standard ahead of five-year regulatory control periods.

Settings of the standard in the NER

The settings of the standard detail the target or objective TNSPs would be obligated to meet like other planning standard set out in the NER. For the system strength planning standard, the NER would contain:

- The requirement for TNSPs to maintain positive AFL and to meet the inverter-driven stability criteria (including setting out exactly what this criteria is as a planning standard.
- The operating conditions for which the standard applies.
- AEMO responsibilities for determining nodes, the amount of generation that the standard takes into account around the nodes and for developing the methodology for how AFL should be calculated by the TNSP. The NER would require AEMO to develop and publish the appropriate guidelines to detail these processes.

These settings could be reviewed on a regular basis by the AEMC as an independent body. Any recommended changes to the settings of the standard in the NER would require a rule change request to be submitted and a determination made.

While this may be perceived to lack flexibility, comprehensive consultation processes involved in AEMC review and rule changes would be appropriate when changing the settings of the standard. The settings of the standard may have large and complex impacts on many different stakeholders in the NEM, including consumers, AEMO, TNSPs and existing generators and developers. Comprehensive review and rule change processes should also ensure that changes to the settings are necessary and enduring, helping to mitigate regulatory risk for generation developers.

Requirements of the standard that sit outside the NER

AEMO and TNSPs both have the technical expertise to determine how the standard defined in the NER is best applied in practice. AEMO and TNSPs would collaborate to best implement the standard at both the planning and procurement stages and so should not find the settings of the standard being fixed in the NER to be restrictive to good power system outcomes as the NEM develops.

AEMO would prepare guidelines that set out the details of how AEMO and TNSPs plan for the standard over time, including how nodes are identified and how TNSPs should calculate AFL. This is consistent with the current system strength framework guidelines.

C SUMMARY OF STAKEHOLDER SUBMISSIONS TO THE DISCUSSION PAPER

This appendix summarises the key points made by stakeholders in their submissions to the Discussion paper. Stakeholder submissions to the Discussion are available at the *Investigation into system strength frameworks in the* NEM project page at our website, aemc.gov.au.

C.1 Issues with system strength frameworks

Stakeholders universally agree with the Commission's proposal to evolve system strength frameworks to a more integrated approach for system strength. Additionally, stakeholders largely supported the AEMC's assessment of issues within the system strength framework.

There was recognition amongst EnergyAustralia, AusNet, Snowy Hydro that some elements of the current frameworks have identified issues with system strength, provide valuable learnings and have maintained system security to date. However, these stakeholders also acknowledge that a more integrated approach would be beneficial.

C.1.1 Minimum system strength framework

The issues highlighted, mainly by renewable and network-focused stakeholders,[121] included the inability of the frameworks to accurately forecast shortfalls and proactively plan to address system strength. Additionally, the framework's inability to recognise challenges faced by distribution network service providers led to inefficient scale economy or co-optimisation efforts.

C.1.2 Do no harm (DNH) framework

The primary issues raised by various stakeholders included issues related to the:[122]

- delays associated with the DNH framework
- costs imposed on connecting generators
- issues with transparency in the associated modelling and remediation requirements
- quality of connecting projects coordination
- inability of the frameworks to acknowledge pre-existing synchronous generator constraints and send investment signals.

The South Australian Government considered that the issues raised on time delays and cost imposts were not in and of themselves reason to adjust the do no harm framework.[123] However, it was also acknowledged that ensuring developers have access to reliable and detailed information about the prevailing system strength conditions and cost implications of remediation would assist in developers' ability to gauge feasibility.

121 Submissions to the Discussion paper: Tilt renewables, Mondo, Clean Energy Council, Citipower, Powercor and United Energy, ElectraNet.

122 Submissions to the Discussion paper: Innogy, ElectraNet, AGL, Enel, Clean Energy Council, TasNetworks.

123 These issues were arguably the correct outcomes of a framework that should be signalling to generators to locate in stronger parts of the grid. SA Government, Submission to Discussion paper, p2, May 2020.

C.2 Evolving the frameworks for providing system strength

Most stakeholders agree in principle with the Commission's approach to considering how system strength can be planned for, procured, priced and paid for.

Some stakeholders recommend additional considerations to this process. Energy Australia, TasNetworks and AusNet noted further considerations to include are practical implementation, complexity of solution, future robustness and the urgency of the issue.

Stakeholders commented on the specific models proposed in the Discussion paper, as set out below.

C.2.1 Model 1: Centrally coordinated

Stakeholders almost universally favoured including some form of centrally coordinated approach to managing system strength, although often in combination with some other option. The only exception to this was Enel Green Power who favoured incremental and targeted reform and preferred models 3 & 4.

Key benefits of the centrally coordinated approach highlighted by stakeholders included:

- the ability of this model to provide investment certainty for generators
- enable scale efficient and long-term solutions
- exhibits greater (concentrated) accountability for critical system security obligations
- building on the current frameworks and system strength procurement mechanisms
- leveraging the current forecasting and planning processes, operational protocols, coordination with other markets services and regulatory oversight
- assists to alleviates the un-coordinated nature of new connections and the negative interaction of different generator control systems with each other.

However, most stakeholders also noted that a centrally coordinated approach is not without its short comings. As such, additional considerations should be made for:

- the role of DNSPs and whether these businesses should be included as a system strength provider with TNSPs
- how generators could support system strength through their plant design
- how conservative forecasting bias can lead to over purchasing of system needs
- alignment with cost causation principles
- how new entrants on system strength will be handled if there is no "do no harm" obligation or incentive and who should procure the service
- what oversight should be in place.

Submissions discussed whether AEMO or TNSPs should be the procurer under a centrally coordinated approach:

- AEMO: AGL, AEMO, Alinta all favoured AEMO as the procurer citing the potential conflict of interest to arise with TNSPs. AEMO procuring services would allow for all potential suppliers – generators, TNSPs and other system security solutions – to compete on a level playing field. Additionally, this process would leverage AEMO experience from procuring other services.

- Energy Networks Australia argued that AEMO procurement would suffer from the same problems as an open market approach, where market power and limited competition could lead to consumers significantly overpaying for the service.

- TNSPs: Infigen, Reach, Tilt Renewables, Electranet, Energy Networks Australia favoured TNSPs to procure resources to meet expected requirements based on forecasts, subject to AER oversight.
  - Infigen noted TNSPs should also procure above the essential level to manage forecasting errors.

C.2.2 Model 2: Market-based decentralised model

Various stakeholders noted efficient risk allocation to those parties best placed to supply the service is an "in principle" benefits of a market-based model's competitive elements.[124]

AEMO, TasNetworks, Snowy Hydro, Hydro Tasmania and Energy Networks Australia were supportive of market-based elements being used in a future framework. They noted a combination of a regulatory approach to provide the essential levels and market-based arrangements for optimising dispatch may be efficient framework evolution.

RES Australia, WSP consultants and AEMO highlighted the challenges with relying on a market-based model alone. This is due to the risks associated with certainty of provision of the service, difficulty with real-time pricing, complexity of optimising security services in real-time and timing to deploy such a market.

Specifically, the AEC noted that "this is a very complicated solution, requiring amendment to the NEM Dispatch Engine," and "the cost and complexity of the solution may not reap the rewards necessary to justify the expenditure.[125]

C.2.3 Model 3: Mandatory service provision model

Generation businesses did not support this model.[126] Stakeholders cited concerns that it would result in over-investment as this model is unlikely to facilitate coordination and efficient provision of the service. Also, this model may compromise project viability and cause investment and connection delay alongside.

Energy Queensland, WSP, EGP, ENA supported elements of this model. In doing so they noted that a flexible application of this model, consistent with the current flexibility inherent in the performance standards framework, could contribute to:

- allocating costs efficiently
- fault level provision
- operating the power system in a less constrained manner

124 Submissions to the Discussion paper: Australian Energy Council, Alinta, Enel green power, Energy Networks Australia, Energy Australia, AEMO.

125 AEC, Submission to the Discussion paper, p. 2.

126 Submission to the Discussion paper: Hydro Tasmania, Snowy Hydro, Engie, Australian Energy Council, Origin, Energy Australia.

- provide efficient locational investment signals.

C.2.4 Model 4: Access standard model

Several stakeholders (AGL, Engie, Alinta, Hydro Tasmania, Australian Energy Council) discounted this model as an adequate solution to system strength. Stakeholders cited concerns in relation to the inability of this solution to contribute to the provision of system strength, imposing unnecessary costs on generators alongside the potential for this model to contribute to operational complexity, over investment and creating barriers to future investment.

CEC, ENA and AEMO supported elements of this model as it may be used in conjunction and have a positive effect on the other model's function. These bodies also acknowledged that retuning generator control systems is a legitimate option that could remediate system strength issues as well as assist reduce the time and cost of connecting generators.

C.2.5 Hybrid models – suggestions from stakeholders

Several stakeholders offered alternative hybrid solutions to addressing system strength. Hybrid being a mechanism that combined elements from two or more of the models presented in the discussion paper.

AEMO, TasNetworks, Snowy Hydro and Hydro Tasmania supported to varying degrees how the attributes of a centralised approach (planning and procurement elements) could be combined with those of a decentralised market-led approach (optimisation or scheduling and dispatch of services). Two notable hybrid models were:

- AEMO presented a hybrid model that encompassed elements of a centralised approach for planning and procurement of system strength services (Model 1) with elements of a decentralised market-led arrangement for the optimisation (or scheduling and dispatch) of system strength services (Model 2). AEMO considered this model to be effective and efficient and align with broader industry wide reform work underway.[127]
- The South Australian Government was supportive of a model that included more centralised planning and coordination of shared assets, in conjunction with a model that preserves the obligation on generators to pay for their share of system strength required to facilitate their connection and operation.

C.3 System strength in distribution networks

Citipower, Powercor and United Energy, and ARENA noted that while distribution networks are facing similar challenges as transmission networks, some unique challenges exist. These include how:

- distribution networks by design have lower system strength than transmission networks[128]

127 AEMO's Renewable Integration Study, implementation of the Actionable Integrated System Plan (ISP) rules, Energy Security Board's framework for Renewable Energy Zones (REZs) and post-2025 design program.

128 These networks are planned with reference to system strength at the transmission connection point and so system strength is heavily reliant on the impedance of the network elements throughout the network.

- the development of the network is not considered within the notion of national flow paths, where the focus is the ISP
- increased inverter-based generation may contribute to voltage level variability and stability issues in the near future.

AusNet note that while system security implication from eroding of system strength in the distribution network is low, the impacts on network services for customers can be severe.

Stakeholder ideas for system strength provision in distribution networks:

- AusNet, and Citipower, Powercor and United Energy note that further consideration of the alignment of issues between transmission and distribution network operation is warranted to inform the appropriate treatment for distribution networks. They consider distribution networks would be better serviced by:
  - generators performing to robust standards to manage differing levels of system strength
  - clarification of the definition of system strength
  - recognising DNSPs system strength service providers (which is limited to TNSPs in the existing framework) and be allowed to identify and address shortfalls.
- Conversely, Energy Queensland does not consider that additional distribution-specific reforms are required in the immediate future.