REVIEW

Australian Energy Market Commission

DISCUSSION PAPER

INVESTIGATION INTO SYSTEM STRENGTH FRAMEWORKS IN THE NEM

26 MARCH 2020

INQUIRIES

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Reference: EPR0076

CITATION

AEMC, Investigation into system strength frameworks in the NEM, 26 March 2020

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 security service, the provision of which is critical to facilitating the transition underway, at the lowest cost to consumers.

2 The current frameworks were put in place in 2017 to address immediate system strength issues. They were successful at keeping the system secure. The pace of the power transition means the time has now come to adjust and expand the system strength frameworks given the rapid connection of large numbers of new non-synchronous generation. These frameworks need to evolve and be agile and flexible given the transition underway.

3 This project will look at evolving the system strength framework, with any changes implemented through rule change requests that are currently pending or expected to the AEMC. This will be undertaken in co-ordination with the ESB's market reform work.

4 In undertaking this work, the Commission will consider how to deliver the system strength needed for security, as well as what is required to support continued investment in new generation, so that consumer demand for energy and so be the long-term interests of consumers will continue to be met.

Context of this investigation

5 Australia's power system is transitioning from one dominated by a small number of large synchronous generators (such as coal and gas) towards one based on a larger number of distributed non-synchronous generation technologies (such as wind and solar).

6 This transition is expected to see a large portion of the current generation capacity replaced by 2040. Approximately 15GW of synchronous capacity is expected to exit the market by 2040, with 30-40GW of new non-synchronous generation entering the market in the same period. To put this in context, the current installed capacity of the NEM is approximately 50GW.

7 Some synchronous generators have already retired, as lower cost non-synchronous generators enter the market, while others are operating for shorter periods. Many of the remaining synchronous generators are approaching the end of their technical life and are expected to retire over the next two decades.

8 A major part of enabling this transition to an increasingly non-synchronous generation fleet will be to change in the way system security services are provided. The coordination of the incentives and mechanisms by which system security services are provided will be essential in maintaining NEM system security at least cost. The ESB, in conjunction with the market bodies, is looking at this as part of its market reform work. One of these essential security services is system strength. The AEMC is working closely with the ESB and the other market bodies on this work.

Purpose of this review

9 System strength supports the stable operation of the power system. It keeps generators connected and operating securely, while also helping to protect the system from faults, such as those that may occur following a lightning strike on a power line.

10 System strength is a characteristic of an electric power system that relates to the size of the change in voltage following a fault or disturbance on the power system. Essential levels of system strength are required to be continuously to maintain a secure power system. Low levels of system strength can jeopardise the ability of generators to operate correctly.

11 System strength is also needed above this essential level to allow generators to operate efficiently, by alleviating constraints on generation and allowing more energy to be provided. In addition, system strength is also needed to provide hosting capacity, which is the ability for new generation to connect to the power system and operate stably and safely. Finally, system strength enhances system resilience, which is the ability of the power system to remain stable following rare, but severe disturbances.

12 The current system strength frameworks were put in place in 2017 to address immediate system strength issues and concerns. Two frameworks were established by the *Managing power system fault levels* final rule for addressing system strength issues:

1. **The “do no harm” frameworks:** new connecting generators are required to deliver system strength commensurate to their 'harm' to the local fault current as a consequence of their connection.
2. **The minimum system strength framework:** addresses declining levels of system strength as synchronous generators retire or reduce their output. AEMO identify shortfalls of system strength, with TNSPs then working to address these expected shortfalls.

13 These frameworks were successful at keeping the system when they were introduced. The pace of the power transition means the time has now come to adjust and expand these system strength frameworks given the rapid connection of large numbers of new non-synchronous generation. These frameworks need to evolve and be agile and flexible due to the transition underway.

Issues with the current frameworks

14 Following engagement with a broad range of stakeholders, the Commission has identified the following key issues where the current minimum system strength framework needs to evolve:

- 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.

15 Stakeholders noted that the need to evolve the current "do no harm" framework. They say concerns have emerged about the current framework acting as a potential deterrent for new entrants in the NEM. As connecting parties under the current framework are required to undertake remediation to address their system strength impacts, this can result in new entrants building, maintaining and operating individual synchronous condensers. This means there could potentially be multiple synchronous condensers being installed across the system. This is in turn can cause increased operational complexity, which may itself potentially create, rather than mitigate, system security risks.

16 Other issues are that the "do no harm" framework is creating or exacerbating include investment challenges, significant delays associated with difficulties modelling a generator's system strength, and increased operational complexity that arises as multiple new connections undertake individual and discrete remediation work.

17 Additionally, the outcomes of the "do no harm" and minimum frameworks can overlap and interact with each other — stakeholders have suggested that these overlaps may not be effectively considered and managed under the current frameworks. This is resulting in outcomes that may not take into account the greater impact on the system across the frameworks.

18 There is also currently no formal linkage with the system strength frameworks and other system security services, particularly inertia, which is managed though a minimum levels regulatory framework that is similar in design to the system strength minimum framework. This means that co-ordination of different security services may be difficult, potentially reducing the ability to capture efficiencies associated with co-ordination.

Conclusion — consider evolving the frameworks

19 The current system strength frameworks have been important in maintaining system security to date. The pace of the NEM transition, consistent with the consensus view from stakeholders, means that current frameworks for system strength need to evolve. The Commission has engaged extensively with stakeholders to gain a better understanding of these issues, with the consensus view from stakeholders being that the current frameworks need to evolve.

20 The Commission agrees that further work is needed to adapt and improve the NER frameworks for system strength. Any changes must be flexible to facilitate the rapidly increasing pace of the energy transition, particularly the expected investment in 30 to 40GW of new generation that which is expected to connect to the NEM power system in the coming decades. The bulk of this new investment will be in new non-synchronous generation, which are dependent on the provision of sufficient system strength to operate safely and securely.

21 The speed at which the transition happens requires a stable and predictable regulatory frameworks, to facilitate efficient investment, in order to promote the long-term interests of consumers.

22 The majority of stakeholders the Commission has spoken to agree that the framework must adjust and evolve given the transition currently underway. This would allow AEMO, NSPs and market participants to take appropriate actions required to mitigate system security risks and support the power system transition.

Considerations for the provision of system strength

23 The starting point to map out what an evolved framework may look like has been to think about the physical characteristics of system strength.

24 It is important to consider the physical characteristics of system strength that affect the valuing, pricing and procurement of a system strength service when designing a new framework. It is therefore necessary to think about the definition of system strength, the

elements of which system strength consists, and its physical attributes most relevant to the design of regulatory frameworks.

What is system strength

25 A system strength service is currently defined in 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. Stronger power systems typically have higher fault current levels (capacity to handle current flowing as a result of a fault or disturbance).

26 More recently, system strength has become a catch-all term for the ability of the power system to return to stable operating conditions following a physical disturbance.

27 Both these definitions have limitations. In particular, they do not recognise the various functions of system strength in maintaining security, and supporting the stable operation of non-synchronous generation.

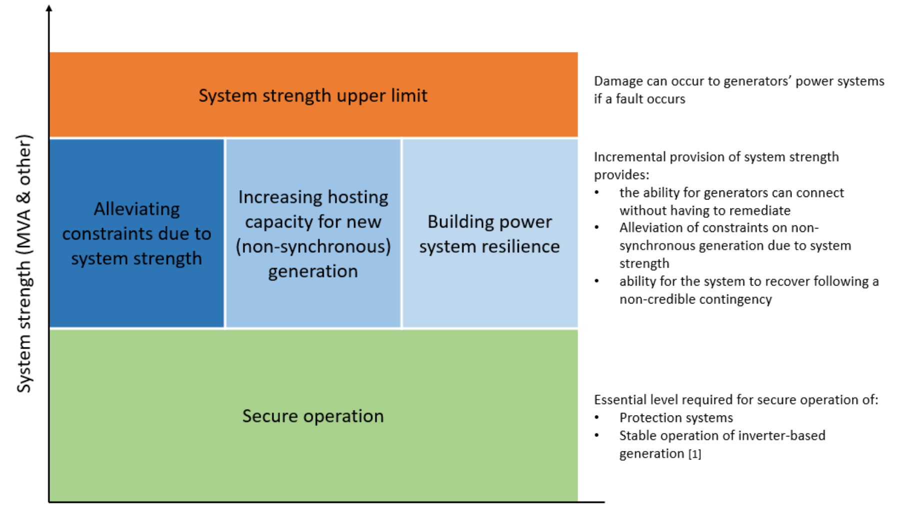
28 This project will clarify what a system strength service is, and what role it plays in a rapidly changing power system. Furthermore, this definition may have different aspects recognising that the service can be procured both passively and actively.

29 Active contribution to system strength refers to the injection or contribution of fault current in to the system. Passive contribution to system strength refers to measures that enable the delivery of fault current (such as through the provision of fault current by a synchronous generator or synchronous condenser) or contribute to stable operation in a system with low strength (such as through tuning inverter control systems in a way that delivers more stable operation of generators under low system strength conditions).

Thresholds of system strength

30 The very broad concept of a system strength service can be broken down into several core components, or threshold levels, based on what the service enables. These threshold levels are described in the figure below.

Figure 1: Thresholds of system strength



Source: AEMC

31 The system strength thresholds shown above are:

- **Essential level required for secure operation:** refers to fault current required for network and generation protection systems to operate correctly, including voltage control system stability (e.g. SVC and switched reactive banks). Additional to this traditional level of fault current, there is also an emerging requirement for an essential level of system strength such that non-synchronous generators can operate stably and do not disconnect from the system, which could result in a security event.
- **Alleviating system strength constraints in the network:** it may become necessary to curtail non-synchronous generation output when available fault level is low in the system. It follows that increasing available system strength may allow for these system strength constraints to be removed.
- **Increase the hosting capacity for the network:** the level of system strength at which new connecting generation would not have to remediate their impact on the operation of the power system or other participants. This may also support faster and less complex coordination of multiple non-synchronous generation connections.
- **Provide a resilience margin:** additional margin that may help stabilise the system following more severe non-credible contingencies.
- **System strength upper limit:** reflects the maximum fault level rating of the transmission lines and substation equipment in that part of the network.

32 The current framework does not value provision of system strength either at or above minimum levels. However, additional investment in system strength, above the minimum level, can potentially remove constraints on the network, and increase the power system's hosting capacity and resilience.

Attributes of system strength

33 System strength has several unique attributes that are relevant to how the service can be provided. These include:

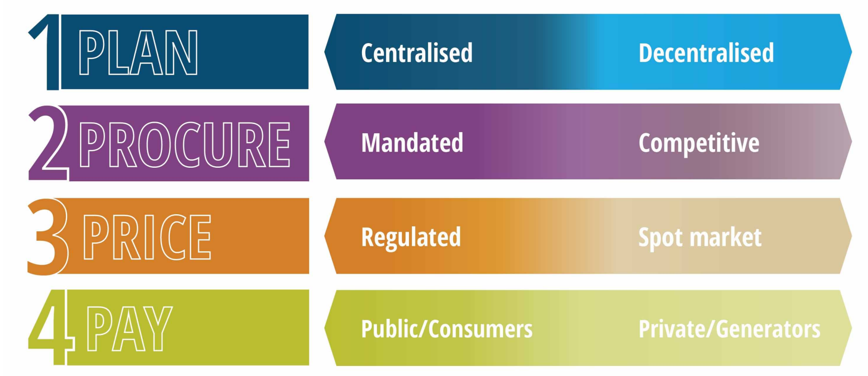
- **Non-linear nature of system strength — a 'lumpy' service:** System strength is referred to as 'lumpy' service and can be difficult for a market to price. Typically, a generator's system strength capability is not proportional to its output, but is instead a binary quantity. That is, the provision of system strength depends only on whether a generator is operational and synchronised to the grid, rather than its incremental MW output. As a result, the service cannot be procured incrementally but is linked solely to a unit's commitment decision.
- **Unit commitment issue:** Unit commitment is the decision made to start a generator, so it can be synchronised to the rest of the power system. In the NEM, the unit commitment decision is made by individual market participants. This is distinct from the centralised dispatch process undertaken by AEMO, which defines what a committed generation unit's output will be. For the purposes of security, having some visibility of a unit's commitment is important to ensure adequate resources are available at dispatch.
- **System strength services are relatively locational-specific:** System strength is locational, primarily determined by the number of synchronous machines providing the service nearby, and the total impedance of the transmission lines and/or distribution lines providing connection to the rest of the network. Areas of the power system where the greatest need is arising, due to high concentration of non-synchronous generation connection, may have limited competition for system strength services.

34 Any framework should be flexible and adaptable to technology change over time - currently there may only be a few technical solutions for the provision of system strength. However, it is likely this will change over time as underlying cost change, and new technologies are developed.

Evolving frameworks for system strength

35 The Commission's approach to considering how to evolve the NER frameworks for system strength is framed around considering how system strength can be **planned** for, **procured**, **priced** and **paid** for. This approach provides a structure for assessing different options for providing system strength.

Figure 2: Approach to developing a new framework



36 **1. How to *plan for* the service? —** this is the process for determining how much system strength is needed and provided in the system, over different timeframes. A crucial element for the Commission is to consider how planning will occur in the longer-term, particularly given the essential need for system strength services as the power system transitions to being increasingly non-synchronous. Short term processes are needed for determining system strength requirements over operational timeframes. Longer term processes are also needed to determine what investments are needed to provide system strength services, to facilitate efficient investment in new generation.

37 **2. By what mechanism(s) is the service *procured*? —** this is the process for sourcing the necessary volumes of system strength, which has implications for how the service is priced. Various mechanisms can be used, including mandating provision from all generators, regulated provision by NSPs, or some form of competitive procurement, for example a market.

38 **3. How do you *price* the service? —** this is the process for determining how system strength is valued and priced. There are two potential ways to approach the way system strength is priced. These approaches may be used in combination or by themselves. These are:

1. The extent to which the service supports system security and resilience, suggesting its value, and therefore price, be measured against avoided loss of load.
2. The extent to which the service reduces constraints on dispatch and facilitates efficient long term investment, suggesting its value, and therefore price, be measured by increased supply of megawatts (MW) to consumers.

39 **4. Who *pays* for the service? —** This is the process of determining which parties should pay for the service. Four main factors to consider are who benefits and who caused the need for the provision of the service, as well as who is best placed to respond and manage the risk associated with the cost of the service.

40 Additionally, all technologies and models are up for consideration in this investigation. This

includes (but is not limited to) the provision of system strength by incumbent and new generators, network businesses using prescribed or negotiated assets or contestable provision, or through non-network solutions. Another important design question will be flexibility, to allows new technology developments to be incorporated as they become viable.

Potential different models to evolve the framework

41 The Commission has used the approach above to map out some models for potential regulatory frameworks for the provision of system strength. These models are not mutually exclusive, and a combination or hybrid of these could be used.

42 **A centrally co-ordinated approach, where networks and AEMO play a central role** — such an approach would aim to co-ordinate and plan the grid into the future, to decide where system strength assets will be required in the medium to long term.

- Under this model, a central buyer, such as a TNSP or AEMO, would be responsible for procuring necessary volumes of system strength to meet a central plan, through either contracting with existing generation, building regulated network assets, or using non-network solutions, to provide system strength services.
- Pricing of these service could be subject to a regulated approach, and could be determined on the basis of the least cost procurement method.
- These services could be paid for by consumers through network charges and/or by generators through a pre-determined fee at the time of connection.
- This model could build on existing planning processes, such as the ISP and transmission planning frameworks.

43 **A decentralised approach, where a competitive market plays a central role in coordination and delivery** — this approach would utilise dynamic, short term procurement of system strength with market price signals supporting longer term investment decisions. This mechanism suggests that system strength could be co-ordinated or co-optimised into central dispatch in some manner.

- "Planning", or coordination, would also be decentralised, with individual parties deciding to participate in the system strength market.
- Procurement of the service would be done at dispatch with system strength assets being dispatched according to their bids to provide system strength to the market, with the least cost combination of assets dispatched.
- The price would be set by the marginal provider of the service, but could be subject to some form of price regulation, if market power is a concern due to a lack of competition.
- The service would then be paid for by consumers through wholesale market costs, and/or by generators through a causer-pays style approach who have a negative effect on system strength.

44 **Mandatory service provision mechanism through imposing direct "active" system strength provision obligations on generators** — this model describes a centralised approach, utilising a generator obligation for level of active system strength provision.

- Planning of this mechanism would be similar to the existing "do no harm" obligation, though through a more simplified approach, such as mandating a given volume of system strength / fault level to be provided by all generators.
- Procurement of the service would be the sole responsibility of each generator and it would be assumed that they would choose the lowest cost option to meet their obligation.
- Generators would bear the direct costs of this mechanism, with consumers indirectly bearing costs through higher wholesale prices, as generators seek to recoup their increased capital costs.

45 **Access standard mechanism through imposing a direct "passive" system strength withstand on all generators** — this model describes an obligation on generators whose connection to the grid would be conditional on having equipment that enables them to operate stably in low system strength environments. It would not require any volume of system strength to be provided, in contrast to the model above.

- Planning of this mechanism would be similar to that already undertaken for generators, including the ISP and connection agreement processes.
- This would result in generators procuring equipment that meets the standard with the price set by the cost of doing so.
- Again, generators would bear the direct costs of this mechanism and would pass on any increased capital costs through increased wholesale prices.

System strength in distribution networks

46 The focus of this investigation relates to transmission networks. However, low system strength is also a growing concern within distribution networks, affecting voltage stability and the performance of inverter connected devices connected to low voltage networks.

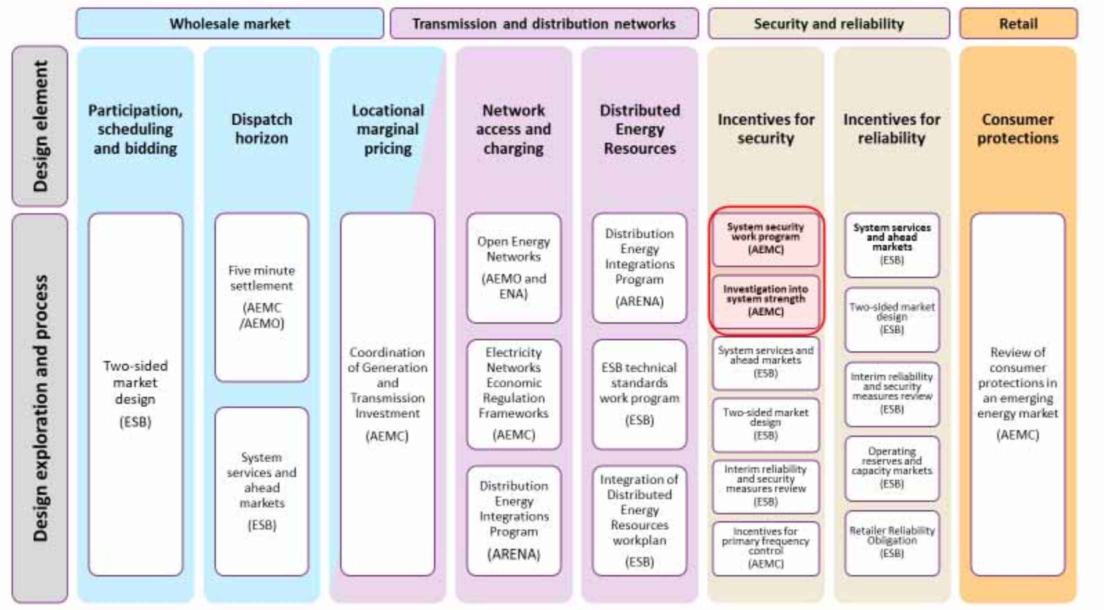
47 The Commission encourages stakeholders to provide insight into the nature, magnitude, and urgency of system strength issues in distribution networks, to inform consideration of these issues.

Next steps

48 The Commission will be holding a workshop on this discussion paper. It will explore the considerations and potential options for system strength further with a wide range of stakeholders to inform how a new framework should be designed. Further detail on the workshop will be made available shortly.

49 The Commission's investigation of system strength frameworks is being co-ordinated with the ESB's market reform work, and with the other market bodies.

Figure 3: Key aspects of ESB's market design work program



Source: AEMC

50 The Commission has a pending rule change proposing to establish a synchronous services market and is imminently expecting at least one other rule change regarding system strength. This project will include the high-level framework design, with these rule changes working through the more granular implementation details for any changes to the frameworks. All related rule changes will be commenced shortly.

51 The AEMC invites submissions on all aspect of this paper by **7 May 2020**. Any and all enquiries regarding this project are welcomed and can be addressed to James Hyatt (james.hyatt@aemc.gov.au or 02 8269 0628). A submission template has also been provided on the project webpage to assist stakeholders with their submissions.

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1 INTRODUCTION

System strength is a critical NEM system security service that is necessary to maintain while the NEM is transitioning. This investigation will consider whether improvements can be made 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. They were successful at keeping the system secure. The pace of the power transition means the time has now come to adjust and expand to system security frameworks given the rapid connection of large numbers of new non-synchronous generation. These frameworks need to evolve and be agile and flexible given the transition underway.

The investigation is expected to be completed by the end of 2020.

Background

In April 2019, the Commission published a consultation paper to initiate the *Investigation into intervention mechanisms and system strength in the NEM*.[1] This actioned a recommendation from our *Reliability Frameworks Review* to review the appropriateness of the initiated interventions frameworks in light of their increased use.[2]

The *Investigation into intervention mechanisms in the NEM* final report was published in August 2019 together with two draft rule determinations relating to intervention pricing and compensation mechanisms. The associated final rule determinations were published in December 2019.[3] The final report's recommendations identified improvements to the efficiency and effectiveness of the intervention mechanisms. Rule changes that seek to implement these recommendations have been lodged by AEMO and will shortly be initiated.

This report continues the system strength aspect of the April 2019 consultation paper.

1.1 A power system in transition

The context of this investigation is Australia's power system is transitioning. It is moving from one dominated by a small number of large synchronous generators (such as coal and gas),[4] to a system based increasingly on a larger number of distributed non-synchronous generation technologies such as wind and solar.[5]

The scale of the current power system transition is expected to see the NEM's current capacity replacing itself by 2040. This means 15GW of synchronous capacity exiting the market by 2040 with 30-40GW of new non-synchronous generation to enter the market to

1 AEMC, *Investigation into intervention mechanisms and system strength in the NEM, Consultation Paper,* April 2019.

2 AEMC, *Reliability Frameworks Review, Final Report,* July 2019, p. xi.

3 See: www.aemc.gov.au/news-centre/media-releases/package-rules-amend-intervention-pricing-and-compensation-frameworks.

4 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.

5 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.

meet demand in the same period.[6] For context, the NEM's total installed capacity is approximately 50GW.

The reduced operation 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, as well as being dispatched less in the wholesale market due to lower cost wind and solar generators being dispatched instead. Some synchronous generators have already left the market with most existing synchronous generators expected to retire in the next 20 years.

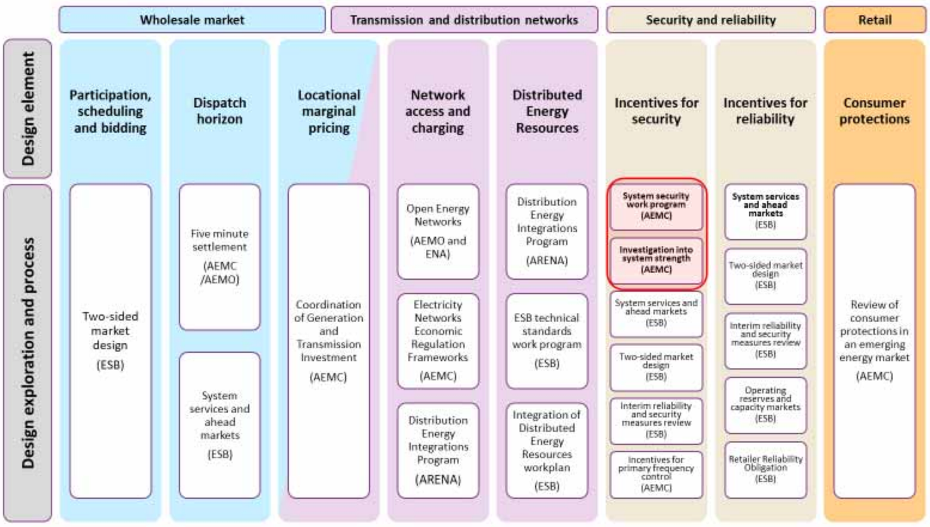
Many of the services required for power system security have traditionally been provided as a byproduct of synchronous generators and have not been separately valued. However, these services are now becoming less available as the energy transition occurs.

One such security service is system strength. The management and provision of this service is critical to maintaining a safe and secure power system, as well as enabling a smooth transition by supporting the integration of new generation of all types (renewables, batteries and so on) as the power system transitions towards a low emissions future.

1.2 Market design to support the transition

There are a significant number of market design reforms on foot lead by the Energy Security Board (ESB) working to support this power transition as shown in Figure 1.1.

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



This investigation will be co-ordinated with the ESB and be a key impact into the system strength services work stream. There may be significant implications for both the design of

6 AEMO, *Draft 2020 Integrated system plan,* 2019, pp. 34-37

any future framework or for other frameworks being designed depending on the outcome of the investigation. As such, coordination with the ESB and the market bodies is critical and front of mind to maximise the effectiveness and efficiency of a future market's design.

1.3 System security services work program

A major part of enabling the power system transition will be changing the way system security services are provided. Coordinating these services' incentives and mechanisms will be essential in maintaining NEM system security at least cost for consumer, now and into the future.

Any changes to regulatory frameworks must be carefully made such that they are proportional, and do not result in unintended consequences and inefficiencies. Additionally, the frameworks will need to be sufficiently flexible to facilitate the required pace of the energy transition whilst securely providing energy.

To this end, the ESB has a system security services work program. The Commission's role in this is to consider and progress rule changes that seek to promote system security in the NEM. These include the following rule change requests: disincentives for primary frequency control; system restart ancillary services, standards and testing; and the suite of intervention and compensation mechanism rule changes, as well as other related rule change requests that may be submitted.[7] In addition, the ESB is working on future market design through its market reform projects e.g. post 2025 project and DER work program.

A co-ordinated work program seeks to implement changes in a consistent manner, resulting in lower cost outcomes for consumers.

The national electricity objective (NEO) is the overarching objective guiding the Commission's approach to this work program. In order to develop a consistent framework for thinking about system security issues, an assessment framework that sets out how new and/or amended system security frameworks will be developed with ESB and market bodies.

This work is ongoing and will facilitate a co-ordinated approach to the management of system security. In doing so it should avoid inefficiencies that can arise where frameworks conflict and realising synergies between services where possible and appropriate. Solving these technical issues are a necessary step in the power system's transition, and to enable more renewable generation to connect.

1.4 Scope of the system strength frameworks investigation

This investigation will consider whether improvements can be made to the system strength frameworks to address declining levels and increasing need for system strength in the NEM, now and in the future. This will be critical for an effective and efficient transition to a lower emissions future due to essential nature of system strength to system security.

7 See: https://www.aemc.gov.au/our-work/our-forward-looking-work-program/power-system-security.

Australia is at the forefront globally of connecting new non-synchronous generators in areas with low system strength.[8] New frameworks to manage this emerging problem were introduced in 2017 and were among the first regulations of their type around the world. These frameworks were successful at keeping the system secure when they were introduced. The pace of the power transition means the time has now come to adjust and expand these frameworks given the rapid connection of large numbers of new non-synchronous generation. These frameworks need to evolve and be agile and flexible given the transition underway.

The majority of stakeholders agree that the frameworks need to evolve and adapt, as the power system transitions. Mitigation refers to measures associated with actively reducing the extent of the impacts of climate change. The Commission recognises that the main mitigation measure utilised in the NEM is the shift in the generation mix to being predominantly renewable energy generators.

Changes to both the minimum system strength and "do no harm" frameworks are being considered to evolve them to be more future proof. These changes are necessary to:

- maintain safe and secure power system operation
- help unlock low cost energy supply for consumers
- facilitate the timely and efficient provision of system strength services
- enable significant volumes of new non-synchronous generation connecting that is occurring as part of the transition of the power system.

1.5 Scope and structure of this report

This report discusses the key issues related to the current system strength frameworks raised by stakeholders and through our own analysis. It begins consultation on potential framework changes for the effective and efficient delivery of this critical system service.

This report's remaining chapters covers the following:

- Chapter 2: key issues with the current system strength frameworks and need to consider evolving the existing frameworks.
- Chapter 3: considerations for evolving the frameworks, including defining system strength and attributes of the service.
- Chapter 4: evolving the system strength framework, including high-level models of how the service could be provided going forward.
- Chapter 5: system strength in distribution networks.
- Chapter 6: next steps and how to lodge a submission.
- Appendix A: introduction to system strength - providing a high-level explanation of the service. This is intended for non-technical stakeholders engaging in this review to understand the basics of the service before reading this report.
- Appendix B provides an overview of the current system strength frameworks.

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

2 KEY ISSUES WITH THE CURRENT SYSTEM STRENGTH FRAMEWORKS

BOX 1: SUMMARY OF KEY POINTS

- The current system strength frameworks have been successful at keeping the system secure. The pace of the transition means the time has now come to adjust and expand the frameworks given the transition underway.
- The key issues with the minimum system strength framework include that it**:**
  - requires revisiting the minimum level definition in recognition of the transition.
  - may not efficiently allocate responsibility between AEMO and TNSPs.
  - is reactive and may not always effectively identify and instigate remediation of system strength shortfalls sufficiently in advance.
- The key issues with the "do no harm" framework include it:
  - may be introducing material uncertainty into the connection process and project development, potentially deterring investment in new generation.
  - requires remediation work, resulting in many discrete, private synchronous condensers being built, maintained and operated. This is increasing operational complexity — potentially creating system security risks, rather than mitigating them.
  - foresaw co-ordination of remediation work between individual generators, which is unlikely in practice due to project financing and timeframes challenges.
- The key issues due to the separation of the "do no harm", minimum system strength and inertia frameworks include that it:
  - was not designed to identify and manage the full consequences of the power system transition - the secondary flow on impacts to dispatch are not accounted for in the "do no harm" framework and are instead indirectly managed through the minimum system strength framework.
  - currently has no formal linkage between the minimum system strength and minimum inertia frameworks, making the realisation of potential co-optimisation efficiencies difficult and instead relies on shortfalls being declared at the same time.
- Stakeholders have suggested that there is currently no formal framework through which to incentive the provision of system strength above the minimum levels. This is despite there being value in doing so to alleviate constraints, providing hosting capacity for new generators and to increase system resilience. TNSPs have suggested that the RIT-T process may not be capable of facilitating investment in system strength due to:
  - the categorisation, or lack thereof, of system strength services,
  - the difficult in predicting the emergence of system strength issues.

- The conclusion from this is that the current system strength frameworks need to evolve and be agile and flexible to facilitate the transition underway. Learnings from the existing frameworks include:
  - Longer-term modelling and planning — Arrangements need to allow for investments in system strength services that address the needs of the system over the long-term, in a more proactive manner.
  - Operational timeframe forecasting — Procuring system strength in an operational time frame would involve modelling the requirements of the system may be prohibitively difficult and uncertainty regarding system strength provision may instead warrant greater conservatism or resilience to be built in determining the system strength levels required.
  - Clear responsibilities for contingency events and associated redundancy — arrangements need to balance procuring enough system strength manage the expected eventualities of the power system, additional margins of system strength to increase power system resilience, and AEMO's role to address non-credible contingency events.

The minimum system strength and the "do no harm" frameworks were introduced in 2017 to address the need to maintain system security. These were successful at keeping the system secure. The pace of the power transition means the time has now come to adjust and expand to system security frameworks given the rapid connection of large numbers of new non-synchronous generation. These frameworks need to evolve and be agile and flexible given the transition underway.

This chapter explores some key issues and unintended consequences stemming from the current frameworks. These issues have been identified through engagement with networks, generators, investors, governments and the other market bodies. They are important to understand in order to consider how the regulatory frameworks can evolve to be made more fit for purpose for the future.

For those unfamiliar with the current frameworks, a more detailed overview of the "do no harm" and the minimum system strength frameworks is provided in Appendix B.

2.1 Current system strength frameworks

On 19 September 2017, the Commission published the *Managing power system fault levels* final rule (the system strength rule). The system strength rule defined the concept of a system strength service in the NER as a "*service for the provision of a contribution to the three-phrase fault level*" at a given location in the transmission network. This means that fault current is used as a measurable proxy for the provision of system strength at a given location.

The system strength rule established two frameworks for addressing system strength issues:

1. The "do no harm" framework, which is designed to deliver any necessary system strength needed as new generators connect to the system. This obligation is imposed on new connecting generators, to address their impact on system strength in a network.
2. The minimum system strength framework, which is designed to address the decline in the amount of system strength in a region. Generally, the intent was to address declining system strength as synchronous generators retire or reduce their output.

2.1.1 Minimum system strength framework

In relation to the minimum system strength framework, the rule requires:

- AEMO to develop a system strength requirements procedure. These will set out how they determine the required three-phase fault level at key locations in each transmission network necessary for maintaining a secure power system.
- TNSPs to procure system strength services needed to meet the required level as determined by AEMO where a system strength shortfall exists and has been declared by AEMO. These services are then enabled operationally by AEMO as needed.

The framework clearly allocated responsibility for system strength to the single party who is well placed to manage the risks associated with fulfilling that responsibility — that is, the relevant TNSP. The framework enables TNSPs to identify efficient, least cost solutions that support long-run efficient operation, use and investment in electricity services.

The rule provides that a TNSP is not required to undertake a regulatory investment test (RIT-T) for the relevant transmission investment if both:

- AEMO requires the system strength services to be provided less than 18 months after the publication of the notice
- The TNSP is not already under an obligation to provide system strength services for that fault level node.

2.1.2 Do no harm framework

In relation to the "do no harm" framework, the system strength rule requires:

- AEMO to develop system strength impact assessment guidelines that set out a methodology to be used by NSPs and generators when assessing the impact on system strength of a new generator connection.
- New connecting generators to "do no harm" to the security of the power system. This means new connecting generators should not adversely impact on the ability of the power system to maintain system stability or on a nearby generating system's ability to maintain stable operation. This requirement applies regardless of whether AEMO has declared a system strength shortfall in a region.

In practice, this means that when a new generator is negotiating its connection with the relevant NSP, a system strength impact assessment would be required to be undertaken by the NSP. The system strength impact assessment determines the impact of the connection of the generating system on the ability of the power system to maintain stability in accordance with the NER, and for other generating systems to maintain stable operation following any credible contingency event or protected event. This assessment would be performed using a methodology set out in the system strength impact assessment guidelines developed and published by AEMO.

The new connecting generator would be required to fund the costs associated with the provision of any required system strength services to address the impact of its connection on system strength. The obligation on new connecting generators only applies at the time the connection is negotiated, based on the information available at that time. After this obligation has been established, it would be incorporated into the connection agreement between the generator and the NSP. TNSPs would then be responsible for maintaining system strength on an ongoing basis (through the frameworks described above).

2.2 Stakeholder views in response to the consultation paper

In April 2019, a consultation paper was published for the *Investigation into intervention mechanisms and system strength in the NEM,* which explored a number of issues with the minimum system strength framework.[9] The Commission recognises that some time has passed since this consultation, and additional engagement with stakeholders has identified some new issues. Nevertheless, the issues identified in the 2019 consultation remain relevant.

The issues raised in the 2019 consultation mostly concerned the approach used by AEMO to determine and declare a system strength shortfall, as well as how TNSPs meet the shortfall.

Stakeholder submissions expressed broader concerns regarding not only the minimum system strength framework, but also the adequacy of the "do no harm" framework. The majority of stakeholders were of the view that the concerns should be addressed by revisiting the frameworks in unison, and by developing a more holistic solution to system strength.[10]

Reflecting on this stakeholder feedback has resulted in this discussion paper considering how to evolve all elements of the system strength framework in the NEM.

2.3 Key issues of the minimum system strength framework

Following engagement through the April 2019 consultation paper, and engagement since then, the following key sets of issues where the current minimum system strength framework needs to evolve:

- The magnitude and definition of the minimum levels of system strength may need to be revised to better recognise the transition underway in the NEM to a low emissions future.
- The minimum system strength framework may not efficiently allocate responsibility between AEMO and TNSPs for providing the minimum level outside normal operation.
- The minimum system strength framework is reactive and may not always effectively identify and instigate remediation of system strength shortfalls sufficiently far in advance.

9 See: https://www.aemc.gov.au/market-reviews-advice/investigation-intervention-mechanisms-and-system-strength-nem.

10 In contrast, ERM Power urged the Commission in their submission to allow the benefits of these relatively new frameworks to be realised before recommending any significant changes.

The April 2019 consultation paper explored a number of sub-issues relating to the existing minimum system strength framework which are now captured in the broader issues discussed in this section.

2.3.1 Magnitude and definition of minimum system strength

The NER requires that AEMO defines the minimum fault levels and fault level nodes such that they can be considered sufficient for the power system to be in a secure operating state. This includes consideration of a region's stability following any credible contingency, protected event, or planned outage.[11]

AEMO's *System strength requirements methodology* (SSRM) sets out how AEMO defines the minimum fault level requirements. The SSRM explains that AEMO uses detailed EMT power system studies to determine minimum fault levels that "ensure the operation of a region's power system" if the outcomes and success criteria defined in the document are met following a single credible contingency event or protected event.[12] This includes considering the requirements to maintain regional system stability if a region is islanded.

However, neither the SSRM nor the NER explicitly include the consideration of an additional margin of system strength in the minimum level to provide power system resilience.[13] That is, for the potential risks of non-credible contingencies. Such margins of additional system strength may be increasingly useful as the behaviour of the NEM becomes more complex with increasing penetrations of non-synchronous generation.[14]

Further, minimum system strength levels may also need to include, and so consider, parameters beyond the provision of fault current. As explained by AEMO in their submission to the consultation paper:[15]

> *System strength is an umbrella term for a range of interrelated factors that together contribute to the stability of the power system. While AEMO understands the need for consistent metrics within the system strength framework, we emphasise the need for flexibility to allow for all aspects of system strength to be appropriately considered.*

The changing nature of the definition of system strength is discussed in more detail in Chapter 3. As noted in that chapter, the current definition of system strength, while appropriate for today, may not be appropriate in the future and so may require modification, particularly given the changing nature of the power system.

Therefore, it is necessary to consider how to:

11 NER Clause 5.20.7(b).

12 AEMO, *System strength requirements methodology,* 1 July 2018, pp. 16-17, 19-20.

13 Here the Commission refers to the concept of resilience as the ability to avoid, survive and recover from a high impact, low probability non-credible contingency. For more information on how such events can be defined, see the final report of the AEMC's *Review of the 2016 South Australian black system event.*

14 This increased complexity may arise due to the sheer number of non-synchronous generation that is being connected, coupled with the fact that the control systems of these generators can interact with each other on complex ways. This complexity of interaction can be exacerbated by low levels of system strength.

15 AEMO, Submission to the *Investigation into intervention mechanisms and system strength* Consultation paper, 23 March 2019, p. 3

- accurately define the minimum levels of system strength (in fault current or otherwise)
- determine the extent to which the unexpected events should be accounted for.

2.3.2 The framework may not efficiently allocate responsibility for maintaining system strength

The minimum system strength framework obliges TNSPs, once AEMO has declared a system strength shortfall in a region, to use reasonable endeavours to make a range and level of system strength services available such that it is likely that when enabled these services will be continuously available. As a result of the continuously available requirement on TNSPs, a certain amount of redundancy is required to be procured to address uncertainties (other than non-credible contingencies, as discussed above) in operating the power system.

Under the current arrangements, a TNSP must make system strength services available 'continuously' to meet a declared system strength shortfall, accounting for planned and unplanned outages as well as protected events.[16] Specifically, the NER require a *System Strength Service Provider* to:

> (2) make a range and level of system strength services available such that it is reasonably likely that system strength services that address the fault level shortfall when enabled are continuously available, taking into account planned outages, the risk of unplanned outages and the potential for the system strength services to impact typical patterns of dispatched generation in central dispatch.

AEMO already accounts for credible contingencies and protected events in setting the minimum levels. However, the framework's obligation above may imply that a TNSP is responsible for procuring additional services. That is, effectively as a redundancy measure to cover planned outages and contingency events (the risk of an unplanned outage) when meeting this minimum level when a system strength shortfall is declared. Therefore, there is a theoretical possibility that protected events and credible contingency events may therefore be accounted for twice; however, the Commission considers this to be unlikely in practice given that AEMO and TNSPs discuss how the power system is operated.

Contracting with existing generators - not valuing the minimum until after a shortfall

Other issues with the existing framework may exacerbate the issue explored above. For example, the NER also require the TNSP to consider "the potential for ... system strength services to impact typical patterns of dispatched generation in central dispatch". This means that if contracting with existing generators for system strength services, a TNSP would have to contract enough units to meet the system strength gap and have to anticipate the impacts of these contracts on changes in the typical dispatch patterns. This occurs because contracting with existing generation risks either pushing other system strength providers out of dispatch or causing them to bid unavailable.

This flow on effect, where non-contracted synchronous generators may be pushed out of the merit order (and are therefore no longer online to provide "free" system strength) could, in theory, lead to a TNSP having to procure sufficient system strength to meet the total

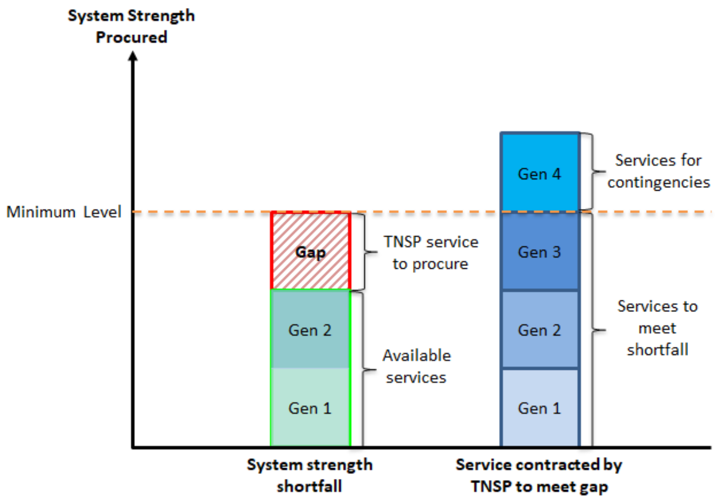
16 NER Clause 5.20C.3(c)(2).

requirement of a fault level node. This may be several times the size of the gap identified by AEMO.

The extent of this is visualised in Figure 2.1. The first column represents the level of system strength the TNSP would be required to procure to meet an identified shortfall. In this scenario, the TNSP only procures the volume in red. The second column shows the two effects described above. This results in the TNSP having to contract for the full volume of services to meet the shortfall (the 3 boxes under the minimum level), plus the redundancy volume above the minimum level, to account for contingencies, although we note that TNSPs procuring this redundancy volume is unlikely.

It is worth noting that "Gen 1" and "Gen 2" are not paid for providing system strength to the system prior to the gap occurring. This means that the minimum system strength level is not valued by the current frameworks until a shortfall occurs and a TNSP must procure the gap.

Figure 2.1: Example of obligation on TNSP to make system strength services continuously available



Source: AEMC

Stakeholders noted in their submissions that allowing TNSPs more flexibility in how they meet a declared system strength shortfall may lead to more efficient outcomes. Stakeholders suggested this flexibility could include allowing a TNSP to meet part of a shortfall or reducing the circumstances the TNSP must account for when making system strength services available.

Stakeholders considered that it may be more appropriate and cost effective for system strength issues arising from unplanned outages (materialised through the contracting of 'Gen 4' in the example above) to be addressed through AEMO's existing directions power. That is, TNSPs are responsible for providing the minimum system strength level, while operational issues (like contingency responses) is managed by AEMO through the definition of the minimum level and real-time interventions when necessary. The Commission is interested in stakeholder views on this.

2.3.3 The framework is reactive

The NER requires AEMO to provide forecasts of shortfalls over a planning horizon of at least five years. This timeframe was expected to allow TNSPs time to react to any shortfall in a timely and efficient manner.

In reality, however, AEMO's current ability to forecast shortfalls is significantly more limited than a five-year horizon. This is due to the:

- complex, iterative nature of the modelling tools chosen to model system strength in order to declare a shortfall
- the high volume of generators currently connecting to the NEM, including uncertainty as to when these generators will connect and the effect they will have on dispatch patterns
- changes in the capabilities and behaviour of new technologies connecting to the NEM.

The current 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. The Commission understands that some TNSPs consider that there is significant uncertainty whether such considerations could be considered through the RIT-T framework, with flow on implications whether the AER will approve expenditure on system strength.

This uncertainty comes in the absence of an identified shortfall and the NER not explicitly setting out an NSP 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.

Further, the experience in South Australia, Victoria and Tasmania was that shortfalls were declared when they are already extant, meaning that there is a relatively limited time for TNSPs to respond and, consequently, limited options for TNSPs to consider. In practical terms, the short-term solution to a system strength shortfall that will have the most significant impact is for a TNSP to contract with synchronous generators. Other solutions, such as retuning generators, may be available.

BOX 2: CASE STUDY: SOUTH AUSTRALIAN SYSTEM STRENGTH SHORTFALL

ElectraNet's experience in responding to the South Australian system strength shortfall in 2017 can be considered to be an example of the reactive nature of the current framework, although the Commission notes that there were a wide variety of other issues influencing this case study. It showed that the framework may preclude TNSPs from timely actions that may deliver a least-cost solution.

ElectraNet concluded that generator contracting was the only potential solution to meet the system strength gap in the 12-month time frame afforded to them by AEMO. However, it found that generator contracting would not be an economically viable solution:

> *The results of our generator tendering process demonstrated clearly that a contracting solution would not be economically viable given that the costs of the contracts required would far outweigh the cost of generator direction currently being incurred in the market.*

Instead, ElectraNet found that the least cost solution in the short to medium term to be the installation of synchronous condensers by the end of 2020 with continuation of AEMO directions to synchronous generators in the interim. Once built, it estimated the synchronous condensers would avoid ongoing direction costs of $2m per month.

It's report estimated the cost of directions at $34 million per annum. However, the report noted that the $34 million excludes the broader cost impact of:

- intervention pricing on wholesale market prices, estimated by AEMO estimates to be in excess of $270 million as at September 2018
- constraining off wind generation.

It is possible that some of these costs may have been avoided had ElectraNet been able to address the system strength shortfall in South Australia earlier. Changes made to the interventions framework by the Commission in 2019 would likely reduce these costs. Further detail on the history of system strength in South Australia can be found in Appendix A.

Source: ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, February 2019.

Forecasting system strength is a highly complex and time intensive task given the current technological limitations and the software of choice (such as PSCAD). This may be limited by the physical realities of the system, particularly the high degree off uncertainty associated with the connection of large volumes of inverter connected, non-synchronous generation. However, it should be noted that the technology used to assess system strength and the general capabilities of forecasting may improve.

As stated in TransGrid's April 2019 consultation paper submission:[17]

> *"[The minimum system strength framework] involves a high risk of shortfalls occurring that are not able to be foreseen with enough warning to address the issue efficiently and at lowest cost. This issue cannot be mitigated by simply asking AEMO to improve its forecasting abilities, or by extending the planning horizon it is required to take into account beyond 5 years.*
>
> *The issue stems from the practical engineering reality that by the time a system strength issue is able to be foreseen with a high degree of certainty, there is unlikely to be enough time to address it in the most efficient way"*

17 TransGrid, Submission to the consultation paper, p. 2.

2.4 Key issues of the "do no harm" framework

A system strength impact assessment is required under the "do no harm" framework when a new generator is negotiating its connection with the relevant NSP. The methodology for this is set out in AEMO's system strength impact assessment guidelines (SSIAG). The obligation requires new generators to remediate any adverse impact, or "harm", their connection causes to adequacy of the local system strength.

System strength impact assessments are time intensive and iterative processes due to the current modelling that is undertaken. In addition, these modelling processes can take significant time to run and model different scenarios given the scale of generation connecting to the network.

Furthermore, the cost of remediation works to address any identified issue may be substantial to an individual connecting generator. It is important to note that neither of these are a product of the "do no harm" framework itself. Rather, these requirements reflect the requirements of physics and what is necessary to increase the penetration of inverter-connected generators in the NEM as we move towards a low emissions future.

In a power system with low levels of system strength, it is a physical reality that complex modelling will be required to assess the impact of each new non-synchronous connection, to assess the impact of the new generator connection on the power system. This reflects the fact that many complex control system interactions may arise and must be accounted for, when large numbers of non-synchronous, inverter connected generators connect to a power system with low levels of system strength. It is also a physical reality that in many cases, some form of remediation will need to be undertaken to address these impacts, either by the generator or some other party.

These outcomes are driven by physics, not regulatory frameworks. However, the experiences of market participants, AEMO, and TNSPs to date have indicated that the "do no harm" framework may not be the most effective way to address and manage these physical outcomes on the power system. These issues with the "do no harm" framework may also not facilitate timely and efficient locational or technical signals to prospective new entrants.

Stakeholder feedback noted that the "do no harm" process is introducing material uncertainty into the connection process and project development and may result in costly and inefficient remediation measures. In aggregate, stakeholders have suggested that the "do no harm" process adds to the barriers to entry already being experienced by new generators, due to low system strength in the NEM. It has been argued that the current "do no harm" framework, in practice, has become a key concern and potential deterrent for new entrants in the NEM.

2.4.1 Challenges to investment — modelling under the 'do no harm' framework

Some stakeholders seeking to invest in new capacity in the NEM have highlighted general concerns about the ability to connect new non-synchronous generation into a low system strength power system. Stakeholders have suggested this is a leading concern that could impact on the feasibility of new generation investment.

Stakeholders have argued this underlying concern is compounded by both the design of the "do no harm" framework and its practical implementation, which they argue impose costs and cause delays for new entrants. Stakeholders argue this results in a negative impact on the risks and feasibility of these projects.[18]

Specifically, the system strength impact assessment process and potential subsequent impact remediation process is seen by new entrants as injecting substantial uncertainties in terms of delays and costs to the connection process. A large portion of this uncertainty is reflected in the complex modelling process that is currently required in order to connect generators, with this complexity being compounded by the significant number of generators connecting to the system and the number of scenarios that need to be modelled.

This section steps through some of the complexities associated with the current modelling requirements which underpin the "do no harm" framework, including how this can impact on the connection of new generation. It then explores some of the implications of this issue.

Difficulties of complex and timely modelling studies

Low levels of system strength are currently seen as a barrier to connection in some parts of the NEM where new entrants are attempting to connect, with this feedback being reflected in stakeholder submissions. These low levels of system strength mean there is limited capacity for new non-synchronous connections in north Queensland, south-west New South Wales, north-west Victoria and South Australia.

For example, Powerlink publishes network limitation advice which noted as at December 2018 there was an opportunity of up to 50MW non-synchronous supportable generation in the Far North area, but that this was not cumulative with any commitment changing remaining capacity.[19]

However, these are also the regions that may have the greatest resource and land availability, which make them desirable locations for new non-synchronous generation. The Commission understands that many (if not all) generators seeking to connect in these regions are currently required to undergo the full "do no harm" process. This includes a Full Impact Assessment (FIA), and requires remediation works to be completed in most cases.

The physics of the system are ultimately driving the need for this assessment and for additional investment in remediation works. However, it is also the case that some features of the "do no harm" process are considered to be exacerbating the challenges of grid connection.

Modelling system strength impacts is a complex but necessary process in the modern NEM

The time intensive modelling required to establish a generator's system strength impact is becoming a necessary norm for new connections. The Commission understands this is typically undertaken using a more complex electromagnetic transient (EMT) modelling software.

18 Clean Energy Council, Submission to consultation paper, 15 May 2019.

19 See: www.powerlink.com.au/network-limitation-advice.

While not an explicit component of the "do no harm" framework, the delays experienced by new entrants are partly due to the fact that EMT modelling at this scale is a relatively new feature for the Australian market, and it has taken time for all parties to develop the capability to undertake this modelling.

Stakeholders advise that generators are struggling to provide accurate models, while TNSPs are going through a rapid process of developing and continuing to refine their models as their learning and understanding improves. They also faced challenges in sourcing the necessary information to undertake this modelling, due to the confidential nature of the highly detailed models needed.

Stakeholders have also advised that their modelling frequently has to be re-run, due to the fact that numerous generators are connecting to the power system simultaneously. Generators may need to redo their modelling as other generators connect in nearby parts of the network, which may add substantially to the time taken to complete modelling.

The 'do no harm' process may become less time intensive for generators as capabilities and experience is developed by the involved parties. However, as the underpinning physics of the system remain unchanged — particularly the fact that multiple generators are connecting simultaneously — it is likely that some effects described here will remain problematic. The Commission is particularly interested in feedback on the time processes that the modelling involves and the implications for the system; significant time delays due to modelling are unlikely to be sustainable.

BOX 3: MODELLING SYSTEM STRENGTH IN THE MODERN NEM

Analysing system strength in a system with high penetrations of dispersed inverter connected technologies differs from system strength in systems with a small number of centrally located synchronous generators.

Operation of a system with large numbers of dispersed inverter connected technologies requires a detailed understanding of how the system will function in low system strength conditions. In particular, how individual generator control systems will behave in such an environment and how these control systems may interact with one another.

Consequently, systems with more inverter-connected generation generally require complex and computationally intensive EMT modelling, which the Commission understands is now standard practice in the NEM and some other international power systems. Power systems are especially difficult to model where they are weak and therefore are subject to large amounts of unpredictable voltage waveform volatility.

Such volatility can cause non-synchronous generators to operate or trip if not carefully tuned to function under low system strength conditions. In turn, this can exacerbate voltage instability in the weak system, creating a risk of cascading failure.

Safe and reliable operation of electrical power systems requires the ability to predict and simulate sources of fault current and the interaction between generator control systems.

> Accurate modelling of power system facilities is essential for the appropriate selection of equipment ratings as well as the setting of protective system parameters for various operating conditions.

Full impact assessments determine key connection requirements but are undertaken late in a project's timeline

A TNSP must perform detailed modelling studies to determine that a proposed new generator will meet its generator performance standards, as well as its system strength obligations, prior to connection to the power system. Stakeholders have advised that as both the ability to connect and the identification of new assets needed for system strength remediation are determined by these studies, they become a prerequisite for the financial close of a project. Consequently, a project is put on hold until these studies are completed.

Preliminary Impact Assessments (PIAs) are conducted after a TNSP receives a connection enquiry, and the Commission understands the outputs of this assessment indicate whether an FIA is required. However, this process does not provide the detail or certainty to usefully estimate the impact of the potential connection or the extent of remediation work necessary.

In contrast, FIA's require connection applicants to supply detailed models of their generator, to undertake the modelling necessary to determine the extent of the connecting generation system's impact. However, these detailed models may not become available to the connection applicant from the manufacturer of the generating equipment until relatively late in the financial process of connecting a new generation system. Generally, connection applicants can not close their financial dealings without a connection agreement and so are already preparing to submit an application to connect to the relevant TNSP, when these studies are performed.

Prior to this process there is little ability for generators to know what their adverse impact on system strength may be at the selected point of connection or what may be required of them to mitigate this impact. As such, investors have limited visibility as to the timeframes and costs of connecting a generator at a certain location during the planning and financing stages of the project. This misalignment between the commercial and technical aspects of connecting a generator creates a significant degree of uncertainty for investors.

Stakeholders have suggested these costs can manifest as a large risk to the project's economic feasibility when these costs are not known in advance or cannot be accurately foreseen when arranging project finance.[20]

New entrants are limited in their ability to undertake system strength impact studies themselves

Undertaking accurate power system modelling of a connecting generator's impact on the system requires access to accurate "input" EMT models of all the other generating units in the part of the system being examined.

20 Infigen, *Response to Post-2025 market design*, 27 September 2019, pg. 13, and Clean Energy Council, Submission to consultation paper, 15 May 2019.

Stakeholders have advised that, due to confidentiality provisions and intellectual property protection requirements, connection applicants are frequently unable to obtain the EMT models of other generating facilities. The inclusion of these models is necessary to accurately assess system strength and other impacts caused by multiple generator interactions.

Consequently, stakeholders have advised us that connection applicants frequently rely on the TNSP for this modelling to assess system strength impacts. This is because the applicants are unable to effectively conduct their own independent analysis prior to lodging a connection application.[21] AEMO are currently beta testing a shareable PSCAD modelling platform to address some of these concerns.

Summary

Given the scale of generation connection, the existing modelling requirements to work out what a generating system's impacts will be, what possible remediation options will be required, and the behaviour of any specific remediation solution to meet a generator's "do no harm" obligation is currently increasing delays to connection for new entrants.

Some issues are intrinsic to connecting a large number of inverter-based generating units to a weak power system. As such, this is a problem of physics, rather than regulatory frameworks. However, the Commission recognises views expressed by stakeholders that some requirements of the current framework may be exacerbating the degree of natural uncertainty that this physical reality is adding to the connection process and the investment prospects of new entrant projects by extension.

Investment challenges due to system strength

Many investors and prospective new entrants perceive that the issues described above impose additional, unnecessary costs for investment.

In recent years, there has been little investment in new synchronous generation capacity in the NEM, while investment in non-synchronous generation has been strong, although it is worth noting that projected generation connections are declining in 2020, compared to previous years. This is despite sustained historically high prices of energy in the NEM, which in theory should send strong price signals for new investment, to replace the generation that exited the NEM between 2012 and 2017.[22] This is explored further in Box 4.

Investment in new capacity and new technology in the NEM will be paramount to promoting a low-cost, low emissions and reliable supply of energy for the benefit of consumers, over the long-term. This will be especially critical given the expected volumes of synchronous capacity that will near the end of its operational life and likely exit the system over the coming decade.

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21 As per formal correspondence with ElectraNet, Response to *Request for information - application of system strength frameworks,* 25 October 2019.

22 Rai, A., and Nelson, T., 2019. *Australia's National Electricity Market after twenty years,* The Australian Economic Review.

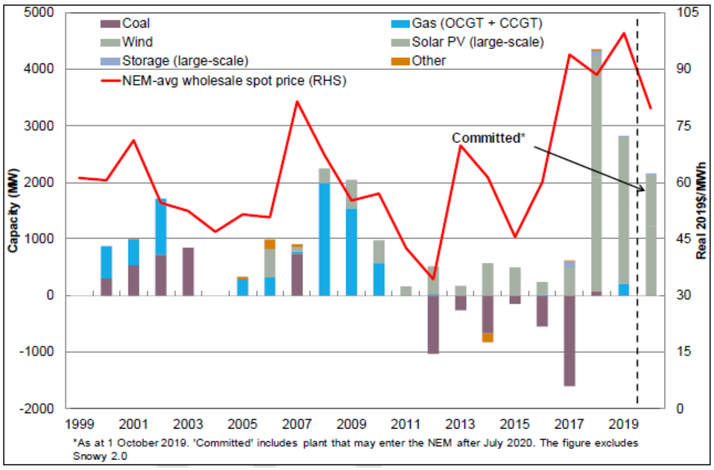
BOX 4: CURRENT NEM INVESTMENT ENVIRONMENT FOR NEW CAPACITY

Investors in the NEM face a challenging investment environment. There are a number of factors that investors consider have raised the level of risk that new projects face, including the following uncertainty surrounding:

- emissions policy, especially after the National Energy Guarantee was abandoned.
- government schemes and their impacts on the market (e.g. the Underwriting New Generation Investment program and state-based renewable policies).
- future technology costs, with renewables and batteries exhibiting rapidly declining cost curves.
- potential spot price impact from higher renewables penetration.
- potential revenues due to changing marginal loss factors and constraints on output.

These factors, and others, have led to an environment where new investment in synchronous capacity has come to a virtual standstill. There is currently no committed synchronous generation in any state except South Australia despite record spot and contract prices across the NEM in 2018-19.

Figure 2.2: Net entry and exit of utility-scale generator across the NEM, by financial year



Source: AEMC analysis based on data from AEMO, the AER and other historical sources.

With the large-scale renewable energy target (LRET) being met, the support provided by the scheme is now minimal, although state schemes such as VRET and QRET are driving entry of renewables. Renewables are generally being underwritten by PPAs, financed by complex hedging arrangements (such as proxy revenue swaps), or are running as merchant assets.

Variable renewable generation is therefore the only form of new supply attempting to enter the power system at this moment in time. If this new supply enters the market, it will increase competition in the generation sector and put downward pressure on spot prices. In the absence of any new supply, spot prices are expected to remain at record levels.

Source: Rai, A, Nelson, T, 2020. *Financing costs and barriers to entry into the NEM's generation sector.*

In an environment where the majority of new committed generation is non-synchronous, stakeholders highlighted the connection process to be a key concern when investing in new generation.[23] Additionally, these parties have identified to the AEMC the "do no harm" process is a key source of uncertainty when determining project feasibility.

Stakeholders have argued that there is no direct 'locational signal' provided to inform potential connection applicants as to likely system strength issues in a particular area. There are indirect signals, such as AEMO's publications regarding the current connection environment in West Murray. These publications warn prospective connection applicants of the long connection timeframes, the necessity of costly remediation work, and that connections would be subject to constraints until network infrastructure investments are completed.[24]

This should influence generators decisions to locate in this part of the network. However, despite this, AEMO note that it is continuing to receive connection applications to the region. This indicates that the uncertainties some stakeholders are experiencing may be due to or exacerbated by a lack of awareness of the current physical complexities of connecting to the NEM.

The lack of a direct locational signal is argued to be due to the complexity and timelines of system strength modelling, as discussed above. Stakeholders acknowledge that connection applicants may need to pay more to remediate their impacts in areas of low system strength. However, much of this potential cost has, to date, not been transparent prior to financial commitment and so has limited influence over where generators choose to connect.

Also relevant is the fact that generators have a right to be connected in the NEM, and there is little coordination of generation connections, with each connection applicant needing to be assessed against the "do no harm" framework on an individual basis, unless they agree otherwise. This is contributing to the modelling processes taking a long time, with multiple interactions of modelling to account for the behaviours of other connecting parties.

Some of these uncertainties are in fact due to the underlying physics of the power system, particularly the fact that large numbers of non-synchronous generators are looking to concurrently connect in low strength parts of the system. However, it is also the case that some uncertainty and risks described above may be linked, at least in part, to the current "do no harm" obligation. In particular, the framework has contributed to uncertainties related to:

- the timing of generator connection and operation
- project administrative and capital costs
- possible constraints on output post-connection.

Evidence of the effects of this include

23 Rai, A, Nelson, T, 2020. *Financing costs and barriers to entry into the NEM's generation sector.*
24 AEMO, *Power system limitations in North Western Victoria and South Western New South Wales*, December 2019

- Both the CEFC and the Bank of America Merrill Lynch have separately found that there is currently an overall average lag to generator entry of approximately 7 months.[25]
- Parties involved in new connections have confirmed to the AEMC that they experience these delays, attributing them largely to the "do no harm" obligations.
- Stakeholders have also indicated that delays to connection can cost a large generator (>300MW) up to one million dollars per week until the project is commissioned.

While these uncertainties may decrease over time as stakeholders gain more experience in dealing with system strength needs, the Commission recognises the value in minimising investment uncertainty where possible, especially considering the complexity of the transitioning NEM and the need for new capacity to maintain supply to consumers.

Additional costs effect on feasibility and financing of projects

Stakeholders have advised that new entrants may incur large costs relative to the total cost of the project when remediating the system strength impacts of its connection.

The majority of remediation work undertaken by connecting generator to date has included the installation of synchronous condensers. Stakeholders have advised that the synchronous condensers being procured by current prospective connections have a capital cost in the order of $20 million (for a 100-200MVA unit), representing an increase of 10-20 per cent in costs being borne by each new entrant as a direct result of low system strength.[26]

In recognition of this issue, Powerlink has been considering how two or more inverter connected generators can share in the system strength provided by a common synchronous condenser facility. Under this System Strength as a Service (SSaaS) model, project proponents will pay a proportion of the costs of the common facility in the form of an annuity. To support such a model, Powerlink has also been considering how an appropriate apportionment of costs can be formulated.[27]

A new entrant must also supply a specialised model of the generator and synchronous condenser to the relevant TNSP to conduct the impact assessment. The cost of this is in the order of $200,000-$400,000 for new non-synchronous generators.[28]

The additional cost is typically only placed on the generator when it is connecting in an area that has system strength equal or below the minimum due to its connection. This creates a "race-to-the-bottom" style desire for generators to connect in that areas of the system with surplus system strength above the minimum. This "race" reduces the available fault current level in that area with those doing so connecting without having to remediate their impacts.

It is also unclear to participants when the minimum level will become apparent and remediation is required. This incentive to connect before the minimum is reached and

25 Infigen, *Response to Post-2025 market design*, 27 September 2019, pp. 11-12

26 TransGrid, Submission to consultation paper, 16 May 2019.

27 As per formal communication between the AEMC and Powerlink.

28 AECOM, *EMT and RMS model requirements* consultant's report to the *Generating systems model guidelines* Rule change, June 2017.

disincentive to connect after it is reached is a very blunt price signal, and may be overall inefficient in signally where and when generators should connect to the system.

Risk of constraint on output

A generator may not be required to undertake any remediation work if its system strength impact at the time of connection is minimal, due to there being adequate system strength at the connection point. However, in accordance with the current connection and access framework in the NEM, the generator has no right to be dispatched and so bears the risk that it may be constrained in future, resulting in it being unable to be fully dispatched and so earn the full potential of the regional reference price.[29]

As the system changes, system strength at points in the network may change as a result of changing dispatch patterns of synchronous and non-synchronous generators. If system strength declines, then AEMO may need to constrain the output of all non-synchronous generators to preserve the minimum levels of fault level for secure operation. This may include constraining off generators who connected in a formerly strong part of the system, and who were not required to undertake any remediation at the time of connection.

Non-synchronous generators that undertake remediation work at the time of connection are currently exempted from being constrained down to maintain available system strength. This occurs where a generator undergoes remediation work at the time of connection. [30]

In South Australia, north-west Victoria and northern Queensland, AEMO is currently constraining down generation that either connected:

- prior to the implementation of the “do no harm” rule
- when system strength remediation was not required at the time of connection.

Some of these generators are being constantly constrained from the date of project commission. This indicates that the system strength in the area of the generator has either:[31]

- declined substantially and unexpectedly
- been found to have been initially inaccurately assessed between the finalisation of the project’s impact assessment and its date of commission.

The AEMC understands, based on stakeholder feedback, that costs to generators of these output constraints are significant enough to warrant certain generators to pursue possible retro-active system strength remediation work to avoid curtailment.

Many of these issues reflect the underlying complexity of the physics of the power system and are not wholly attributable to the "do no harm" regulatory frameworks. However, it is also suggesting it is necessary to consider whether better coordination or forecasting could alleviate some of these uncertainties.

29 Under the NEM’s current access regime generators have a right to connect to the network, but no right to be dispatched. This is consistent with the fact that generators pay only for the cost of their own connection assets, and are not required to fund augmentation of the "shared" network.

30 ElectraNet, 2019 TAPR, June 2019, pg. 50.

31 As per formal correspondence with ElectraNet, Response to *Request for information - application of system strength frameworks,* 25 October 2019, and AEMO, *Notice of Victorian fault level shortfall at Red Cliffs*, December 2019.

2.4.2 Increased operational complexity arising from individual, discrete remediation

Many of the delays discussed in previous sections are a result of sourcing, commissioning and testing of synchronous condensers required by new entrants to remediate their system strength impact. The remediation work being required by the "do no harm" obligation is resulting in multiple individual synchronous condensers being built, maintained and operated by each new entrant.

This may result in increased operational complexity and could create, rather than mitigate, system security risks. Stakeholders have suggested that having a more co-ordinated manner of installing remediation measures could be a cheaper and more operationally effective solution. Coordination of remediation work is discussed further in section 2.4.3.

> **BOX 5: "DO NO HARM" REMEDIATION THROUGH THE INSTALLATION OF SYNCHRONOUS CONDENSERS**
>
> New connections can remediate their impact in numerous ways depending on the nature of their impact, with this identified in AEMO's SSIAG. Options include installation of synchronous condensers, use of grid-forming inverters and/or tuning generator control systems. Many generators that have connected to date that have had to comply with the "do no harm" obligation have opted for synchronous condensers.
>
> A few generators have agreed to specialised tripping schemes that remove the generator from service when local levels of system strength dip. However, this is not an option that seems to be available for the majority of generators. As described in AEMO's 2019 VAPR, the triggering of runback schemes can result in large generation losses. This represents sizable contingency events, particularly in areas where multiple generators may need to be runback simultaneously.

Source: AEMO, System strength impact assessment guidelines, June 2018. AEMO, 2019 VAPR, June 2019, pp. 49-5

Problems with individual, discrete remediation

The synchronous condensers being built by each new entrant will have different operational characteristics depending on their size, control settings and how they are operated and maintained. They are also likely to operate only when the host generator is operating.

This introduces additional operational and modelling complexity for AEMO with each new connection, a point supported by TransGrid's submission to the April 2019 consultation paper:[32]

TransGrid suggested the reasons for this lack of optimisation and increased costs include:

- Synchronous condensers are not being installed in optimal locations to support the power system beyond the host new entrant, nor are new entrants likely to provide system strength services beyond that required for operation due to associated operation costs.

32 TransGrid, Submission to the consultation paper, pp. 3-4.

- TNSPs will likely still need to procure system strength separately for system security, as they cannot always rely on the operation of generators' synchronous condenser. This may be a missed opportunity to co-ordinate power system and new entrant system strength needs.
- The installation of several smaller synchronous condensers increases the complexity of the system. AEMO and TNSPs would be subject to increased modelling and operational costs while proximate, individually operated synchronous condensers could create challenges in coordinating control systems and managing adverse interactions.
- A more complex power system may also increase the costs and delays of new entrant connections. These costs are significant and create unnecessary barriers to entry for prospective generators, further limiting competition in energy services.

Lack of visibility and control of system strength assets

New entrants have no regulatory incentive to optimise their individual remediation schemes for maximum benefit to the network and overall power system, and are likely to be operated in a way that is consistent with the needs of the generator. Some generators have responded to commercial incentives and have installed additional system strength remediation requirements in order to then "sell" this service to other generators in the surrounding area. However, generally, TNSPs may have to account for the operation and interaction of multiple individual remediation schemes in its network without full visibility or control over their exact operation and behaviour.

There is a question whether TNSPs may be best placed to make sure synchronous condensers are optimally sized, tuned, maintained and operated, given their greater visibility over the system strength needs of the network.

While the current NER already allow for TNSPs to complete remediation work and be reimbursed by generators, the Commission understands this option has typically not been used since new entrants prefer to manage remediation issues directly. There are also difficulties in coordinating remediation work across multiple parties given that generators are competing in a competitive wholesale market.

2.4.3 Challenges and benefits of coordinating system strength remediation

Stakeholders have suggested that coordinating the build of synchronous condensers could be a more economically efficient option than the current approach, although the practical challenges of aligning project timeframes and financing make coordination unlikely in practice for the "do no harm" framework.

It is worth noting that the challenges TNSPs experience in trying to co-ordinate shared assets between new entrants are not unique to system strength and are experienced by connecting parties more generally due to confidentiality, project timing and financial risk issues.

Given the locational aspects of renewable resources, many new entrants are connecting electrically close to each other, creating the opportunity for individuals to share some or all of their remediation works where there are economies of scale to be realised. The value to new entrants of coordinating remediation work is particularly evident when installing synchronous condensers as network side, shared assets.

Synchronous condensers are well suited as a co-ordinated solution to system strength remediation for new connections, as they:

- do not need to be built onsite with a generator if locating them at a network element (like a TNSP substation) where it more effectively mitigates the impact of the new connection
- can provide support for more than one new connection provided they are sized, tuned and operated appropriately,
- can be significantly upsized at little marginal increase in cost.[33]

The optimal location for system strength provision is often a local transmission substation. This can result in multiple issues arising, including the:

- Complicated TNSP-generator arrangements whereby the asset is owned and operated by the generator but needs to interface with the TNSP equipment, having complex interactions with other network elements at the substation.
- If generators choose to operate the synchronous condenser, they may have little experience in this.

Powerlink estimates that there are 40 or more projects wanting to connect across Queensland. But the lumpy nature of current system strength solutions, as well as the inability for projects to co-ordinate their remediation work may result in some generators installing bigger than necessary synchronous condensers due to the limited selection of "off the shelf" options in the market.

The Commission has been advised by both Powerlink and ElectraNet they have been approached by connecting parties interested in taking advantage of any possible co-ordinated remediation work. Powerlink has also suggested that the technical feasibility of such coordination is possible given the ability to ringfence the benefits of a shared synchronous condenser to the appropriate connections.[34]

Better coordination may reduce the number of synchronous condensers needed. Given the small number of suppliers of synchronous condensers globally, this would help new connections to avoid supply bottlenecks that may be experienced if each individual connection applicant is required to remediate their own system strength impact and look to install synchronous condensers. However, as discussed in chapter 3, it is still important to consider whether synchronous condensers are a sustainable longer term solution.

The Commission is not aware of any shared, co-ordinated remediation works that have proceeded to finalisation as yet. Powerlink has identified two key barriers to its realistic implementation:

33 As per formal correspondence with ElectraNet, Response to *Request for information - application of system strength frameworks,* 25 October 2019.

34 As per formal communication between the AEMC and Powerlink.

1. Connecting generators do not have sufficient access to the technical information of other existing and connecting generators to facilitate productive multi-party discussions and analysis of potential shared remediation options.
2. The timelines for connection of different parties are unlikely to closely align, yet neither the connecting parties or the TNSP want to take on the risk of a stranded asset in the event the other project falls through.

Regarding the second point, coordinating parties must also consider who takes responsibility for a shared asset if one of the parties retires.

The need for more information to facilitate coordination between connecting parties was a partial driver for the Commission to make a recent final rule to increase transparency of new projects connecting to the network.[35] However, the Commission understands that rule will not fully address the barriers to effective coordination of remediation works between connecting parties.

2.5 Key issues due to the separation of the "do no harm", minimum system strength and inertia frameworks

The Commission and stakeholders have noted that separation of the "do no harm" and minimum system strength frameworks, as well as the separation of the system strength and inertia frameworks, create some inefficiencies.[36]

In general, the current outcomes of the individual frameworks interact with each other, yet these overlaps cannot be effectively considered and managed. This may result in an environment where the frameworks can be triggered iteratively and produce outcomes that do not account for potential flow-on effects or potential opportunities to co-ordinate across the frameworks. These issues are explored below.

2.5.1 Key issues due to separating the system strength frameworks

There are a number of interactions between the "do no harm" and minimum system strength frameworks which may result in economic and operational inefficiencies in the NEM. These are discussed below.

Flow on consequences of increased non-synchronous penetration

The intent of the “do no harm” obligation is to neutralise the local system strength impact of a connecting generator. That is, the connecting generator is required to remediate any direct adverse impact it has on the technical and operational envelope of the system, where this would threaten the secure operation of the power system.[37]

35 AEMC, *Transparency of new projects, Rule determination,* October 2019.

36 AEMC, *Investigation into intervention mechanisms and systems strength,* pp. 132-133 and Submissions to the consultation paper, TransGrid, p. 2; TasNetwroks, p. 7.

37 Secure operation includes the ability for the power system to maintain system stability during normal operation and following credible contingency events and protected events. In areas of the power system where there is no available fault level above the required minimum fault levels (as determined by AEMO) at the proximate fault level nodes, new connections would have to correct or remediate their system strength impact on the power system.

As described further in chapter 3, non-synchronous generators typically have a negative impact on local levels of available fault current to support the stable operation of non-synchronous generation, due to the inherent characteristics of power system electronic connected, grid following inverters. Non-synchronous generation is therefore more likely to be required to undertake remediation work under the "do no harm" obligation.

The "do no harm" framework is designed to address the immediate impacts of the connection of non-synchronous generation. However, it is not designed to account for any secondary, flow on impacts on dispatch, which may themselves inadvertently further reduce available fault current. These secondary, flow on effects stem from the fact that increased VRE generation output may influence patterns of dispatch, including reducing the extent to which synchronous generators are dispatched, as discussed above.

Consequence of this displacement effect

If this effect is sufficiently pronounced, it may trigger AEMO to declare a shortfall in system strength. In this way, the "do no harm" framework could potentially create the situation where even though a non-synchronous generator has fully remediated its own impact, it may nevertheless end up operating in an environment with lower levels of system strength than those against which it was originally assessed.[38]

It is important to note that dispatch outcomes are complex and iterative processes. That is, no single non-synchronous generator can necessarily be identified as the primary driver of dispatch changes, reductions in synchronous dispatch, or any subsequent reductions in system strength.

However, it is also true that this displacement effect in areas with little or no system strength above the minimum levels could cause the typical fault current in an area to drop below the minimum required levels. This would constitute a system strength shortfall under the minimum system strength framework.

Therefore, the broader impacts of increased connection and output from non-synchronous generators on overall system strength provision is indirectly managed through the minimum system strength framework.

If a TNSP does not have adequate lead time to procure system strength services before this kind of shortfall occurs, AEMO has managed levels of system strength in the shortfall region in two ways, by:[39]

1. directing specific synchronous units if adequate combinations are not online/committed
2. constraining the output of non-synchronous generators.

As such, the "do no harm" obligation in isolation does not necessarily comprehensively address a new non-synchronous generator's total contribution to changes in overall levels of on system strength. The Commission considers this indicates a more co-ordinated approach

38 The effects on local levels of system strength of a new connection is dependent on the location of the synchronous generator units that get pushed out of dispatch.

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

is necessary. This is to more accurately identify and manage the full consequences of the change in the generation fleet from synchronous to increasingly non-synchronous.

Difficulty in coordinating remediation across both frameworks

There is currently no formal linkage between the minimum system strength framework and "do no harm" framework. This means that there is no clear ability for both aspects of system strength impacts to be addressed in a co-ordinated manner. The result can be additional costs, due to inefficient duplication across multiple, separate remediation works.

Each framework has different cost recovery mechanisms, which can add challenges in seeking regulatory approval for the TNSP to build shared assets and in the cost recovery of those assets. It may be difficult to ringfence portions of a shared assets service and allocate proportional costs to generators and consumers.

For example, it may be efficient for a TNSP to take action to address a system strength shortfall and, at the same time, undertake remediation works that are required under the "do no harm" framework. This could work such that a TNSP could build a larger synchronous condenser to address both a shortfall as well as the remediation required to connect new non-synchronous generators.

2.5.2 Inefficiencies of separating the system strength and inertia frameworks

There is currently no linkage between the minimum system strength framework and the minimum inertia framework. This means that co-optimisation between the frameworks is difficult and relies on shortfalls for both services being declared at around the same time.

In South Australia, AEMO declared an inertia shortfall a year after declaring the system strength shortfall. This allowed ElectraNet to recover the cost of adding flywheels to the synchronous condensers being installed to meet the system strength gap declared earlier. Had the inertia shortfall not been declared at this time, an opportunity for efficient co-optimisation of system strength and inertia would have been missed.

In November 2019, AEMO declared concurrent shortfalls in system strength and inertia in Tasmania. This will enable co-ordinated solutions to be developed in response.

Although in practice AEMO may be able to declare concurrent inertia and system strength shortfalls, the Commission considers that a formal linkage would be preferable. This will better allow for co-optimisation, so that efficiencies can be realised by design rather than by relying on shortfalls being declared at or around the same time.

For example, if a shortfall in system strength has occurred and a shortfall in inertia is yet to occur but is likely to arise in the near to mid-term, there may be value in considering how to address both issues simultaneously. This could include making low cost, incremental additions when sourcing solutions for a system strength shortfall — such as procuring synchronous condensers with flywheels to provide inertia. Such "readiness strategies" can deliver efficiencies while minimising costs to consumers. A point made by in TransGrid's April 2019 consultation paper submission.[40]

2.6 Recognising the benefits of providing system strength above the minimum level

The two system strength frameworks focus on always maintaining a base level of system strength. However, there are circumstances where it may be valuable to encourage or require the provision of additional system strength above these levels to provide additional resilience to non-credible contingencies, to alleviate constraints on non-synchronous generation or to facilitate efficient new investment. There are currently no formal frameworks to capture these potential values of system strength above the base levels.

The Regulatory Investment Test for Transmission, or RIT-T process, allows a TNSP to elect to invest in system strength services on the basis that they will deliver market benefit. This can be done in conjunction with investments made in response to a system strength shortfall notice, or independently of such a process.[41]

However, multiple TNSPs have suggested to the Commission that the RIT-T process is not completely capable of facilitating investment in system strength services. TNSPs have suggested the key reasons for this are:

- System strength is not currently categorised as a regulated network service, or a network standard that it must meet, and so the need for a TNSP to provide the service is difficult to justify in a RIT-T.
- It is hard to accurately predict when a system strength issue will occur and how it may manifest, which makes analysis of economic benefits less definitive.

TNSPs can and do take into account the impacts of large retirements, outages and constraints on generation through the RIT-T and Transmission Annual Planning Report (TAPR) processes. However, the Commission understands that these considerations are difficult to extend to direct action through these projects that may realise any perceived economic benefits of provided additional system strength services. This includes limitations to procuring addition system strength services in anticipation of potential shortfalls.

The Commission intends to further examine this argument from TNSPs as to the potential limitations of the RIT-T to allow for consideration of further benefits to the NEM of providing additional system strength. This issue is discussed in further detail in Chapter 3.

2.7 Conclusion

System strength is a critical NEM system security service that is necessary to support the transition to low emissions future. The current frameworks were put in place in 2017 to address immediate system strength issues. These frameworks were successful at keeping the

40 TransGrid, Submission to the consultation paper, p. 4.

41 Noting comments from TNSPs that in the absence of a declared shortfall from AEMO, the current RIT-T process may not provide sufficient certainty that expenditure for system strength needs may not be allowed by the AER.

system secure. The pace of the power transition means the time has now come to adjust and expand system security frameworks.

Experience to date with the system strength frameworks suggests that the current frameworks are not optimally suited to facilitating the transition to a future power system with a very high penetration of non-synchronous generation. Future regulatory frameworks for system strength will need to recognise the different values that system strength can provide, including system security, resilience, alleviating constraints on dispatch and supporting efficient investment in new capacity.

The bulk of the new capacity expected to enter the system is likely to be variable renewable energy generation, and a substantial portion of that is likely to be non-synchronous generation. Given the dependency of this form of generation on available levels of system strength, an agile and flexible framework is needed to deliver necessary levels of system strength. Without one risks causing inefficiencies.

The current system strength frameworks therefore need to evolve given the power system transition underway. Through this project the Commission will consider how an evolved system strength framework can deliver efficient and effective outcomes in the long term interests of consumers. Any findings will be implemented through the pending rule change request(s).

2.7.1 Learnings from the existing frameworks

The issues explored in this chapter will inform any regulatory changes, especially the design of a future system strength framework. The key learnings from the existing frameworks are:

- **Longer-term modelling and planning —** Arrangements need to allow market participants and planners to make investments in system strength services to address the needs of the system over the long-term, in a more proactive manner. It is important to strike an appropriate balance between accuracy and timeliness, given there is a trade-off:
  - Investing in options before the need for them is well-defined and highly probable could result in redundant equipment being installed. This creates the risk of asset stranding that could risk of inefficient costs being borne by consumers (depending on how the costs of the assets are recovered).
  - Only declaring shortfalls when they can be defined with a high degree of certainty, may not allow time to invest in least cost options and may result in the need for a highly reactive operational responses. This include AEMO being required to issue directions to synchronous generators, or constraining output of non-synchronous generators in order to maintain system strength.
- **Operational timeframe forecasting —** Procuring system strength in an operational time frame would involve modelling the requirements of the system in real time to identify how much system strength is needed and where it is needed in the power system.

The Commission understands that modelling system strength dynamically to inform any dispatch decisions of generators on a real-time basis would be prohibitively difficult given the scale and complexity of AEMO's current EMT-based models. Additionally, experience has shown that the actual performance of the power system differs markedly from the modelled predictions due to modelling limitations and system instability.

This uncertainty regarding system strength provision may warrant greater conservatism or resilience to be built in determining the system strength levels required. This would be to cover the potential gaps in generation commitment, coordination of generator and network-owned assets, and the accuracy of AEMO's system strength models due to the affects of less predictable generation dispatch.

Any changes to the framework must account for the difficulties in being able to procure and co-ordinate the required levels of system strength for each dispatch interval.

- **Clear responsibilities for contingency events and associated redundancy —** As the penetration of non-synchronous generation increases across the NEM, with new capacity typically located away from load centres, existing generators may be increasingly less well-placed to provide system strength effectively.

  Over the long term, the continuing retirement of the existing thermal fleet will eventually give rise to the need to again reconsider how system strength is provided or procured in the long-term. The question of considering what other options can provide system strength beyond existing generators is therefore a question of "when", not "if".

  Regardless, any mechanism to provide system strength will need to agile and flexible, as existing synchronous plant retires and so the need for system strength provision increases. The Commission considers that there is a balance to be struck between procuring enough system strength to manage the expected eventualities of the power system, additional margins of system strength to increase power system resilience and AEMO's role to address non-credible contingency events. Furthermore, maintaining adequate levels of system strength is a permanent requirement and so the provision of system strength must be reliably consistent.

3 CONSIDERATIONS FOR PROVISION OF SYSTEM STRENGTH

BOX 6: SUMMARY OF KEY POINTS

- System strength is an important characteristic of a power system that is necessary for secure operation. An essential level of the service is required for the power system to:
  - remain stable under normal conditions
  - return to a steady state condition following a system disturbance.
- **Definition of system strength:** The definition of system strength service in the NER is "a service for the provision of a contribution to the three-phase fault level" at a given location in the transmission network. More recently, system strength has become a catch-all term for interrelated factors that together contribute to power system stability.
- **Sources of fault current:** Fault current is one of the key aspects of system strength. In the NEM, existing synchronous generators have historically been the primary suppliers of fault current, and therefore system strength. Other synchronous machines that can contribute positively to the total fault level include synchronous condensers, synchronous generators capable of running in synchronous condenser mode, or large synchronous motors, such as a pump. Additional ways to contribute positively to system strength in a power system include network augmentation, and tuning inverter-based technology.
- **Why is system strength needed?:** Currently, system strength is a requirement of operating utility scale power systems. A power system with low levels of system strength will likely experience higher levels of network voltage volatility during periods where the system is operating under normal conditions and during a disturbance, with this impacting on both generation and loads.
- **The provision of system strength in the NEM:**
  - The provision of system strength in the NEM may decline in the future as a result of synchronous generator retirement or the displacement of synchronous generation by non-synchronous generation in the wholesale market.
  - The essential level of system strength required to maintain a secure and reliable grid is likely to increase in areas of the network with growing levels of newly connecting non-synchronous generation.
  - The provision of additional system strength in the NEM can provide various system benefits, ranging from supporting system security, to removing constraints on dispatch and "freeing up" network capacity for new generation investment.
- **Attributes of system strength:** System strength has unique attributes that affect how it is planned for, priced and procured. Understanding these characteristics is central to addressing the key challenges and trade-offs inherent in developing mechanisms for the provision of system strength. These attributes include:

- **Binary, lumpy nature of system strength:** The provision of system strength by a synchronous machine is not proportional to the MW output of the generator providing the service. Once a synchronous machine is contributing to the provision of system strength, its contribution represents the entirety of its system strength capability.
- **Unit commitment issue:** Currently there is no ability for a market signal or interventions by AEMO to adjust the levels of system strength, as provided by existing generators, in real time. System security therefore relies on the physical commitment of synchronous plant ahead of time.
- **System strength services are relatively locational-specific:** The system strength at any given location is primarily determined by the number of synchronous machines nearby that are capable of injecting fault current, as well as the number of (relative impedance) transmission lines or distribution lines (or both) connecting synchronous machines to the rest of the network.
- **Interactions with energy and other security services:** The provision of one security service may come with the co-benefit, or in some cases the detriment, of others. Opportunities may exist to co-ordinate and or co-optimise these services as a number of system security services are physically interrelated.

- These attributes have led to AEMO determining specific combinations of synchronous generators that must be online for secure operation. These attributes are also relevant considerations of how to plan for, procure, price and pay for system strength, underpinning the various potential future models considered in the next chapter.

System strength has certain characteristics that affect how it needs to be planned for, procured, priced and paid for. Understanding these characteristics is central to addressing the key challenges and trade-offs inherent in developing mechanisms for the provision of system strength.

This chapter explores system strength in relation to:

- What it is and whether the current NER definition of a system strength service is fit-for-purpose, given what the industry has learned since the term began being used.
- Why it is needed for secure system operation.
- Ways it can currently be provided and is currently managed, and the challenges, needs and opportunities this presents.
- Several unique attributes it has and the implication this has on the provision of the service.

3.1 What is system strength?

System strength is an important characteristic of a power system that is necessary in order for it to operate effectively. It can be described as a characteristic of an electrical power system that relates to the size of the change in voltage under normal conditions and the ability of the power system to return to a steady state condition following a fault or disturbance on the power system. When system strength is high at a particular point in the network, then the voltage changes very little when there is a change in power flows (by changes in either load or generation) at that part of the network.

Not having enough system strength is a technically complex power system issue that has manifested more prominently in the NEM as compared to international power systems, primarily due to the unique nature of the Australian transmission configuration and rapid change in generation mix. Such complexity can be challenging to understand for some potential investors in new generation capacity, particularly where these investors are new to the Australian context or the energy industry in general.

System strength is typically measured by the available fault current at a given location and is sometimes also measured by the short circuit ratio.[42] Fault current refers to the current which flows as a result of a fault or a disturbance in the power system. A related measure is the short circuit ratio (SCR), which describes the relative system strength at the connection, calculated as the ratio of the fault level in MVA and the rating of the non-synchronous connected generation at the connection point, measured in MW.[43] Stronger power systems typically have higher fault current levels and higher short circuit ratios.

The fundamental physical aspects of system strength must be considered prior to considering what regulatory frameworks are appropriate for the provision of system strength. This is particularly pertinent given the NEM's experience managing system strength to date.

Over the last few years, AEMO, TNSPs and market participants (both incumbent and newly connecting) have developed a growing understanding of this complex phenomena, and the nature of its fundamental aspects.

This new understanding of system strength includes new ways of thinking about exactly what it is and what it does for the power system, what drives and influences it, and how best to maintain and manage its provision. These in turn form fundamental considerations for how system strength can be provided in the NEM. The following section explores these considerations.

3.1.1 Defining system strength

While the overall concept of system strength is not explicitly defined in the NER, the NER has set out a technical definition of the provision of a system strength service. As discussed below, while this definition illustrates an element of what could comprise a system strength service, other elements of this critical service are still coming to light.

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.[44] Fault current refers to the current flowing towards and into a fault or a disturbance on the line. Stronger power systems typically have higher fault current levels.

42 AEMO, *Transfer limit advice - System Strength*, p. 12, September 2019.

43 CIGRE B4.62, Section 1 and equation 6.1

44 National Electricity Rules, Chapter 10 Glossary, Version 132, p.1318

This definition provides a metric against which system strength service can be measured, both in terms of the volume and where it is being provided. This has been important in the practical implementation of the minimum system strength framework. Adequate fault current is also required for protection systems to detect and isolate faults and the stable operation of inverter based generation. Low levels of fault current can increase the likelihood of protection system maloperation and inverter based generation stability.

Since the time this definition was inserted into the NER, power system engineers have been doing more studies, and there is now increased understanding and views around what system strength is.

Progression of thinking on system strength

More recently, system strength has become a catch-all term for a suite of interrelated factors that together contribute to power system stability. This is the ability of the power system to maintain stable operation. For example, more recent definitions of system strength by AEMO are broader and include:

- *sensitivity of power system variables to disturbances* — this specifies that system strength indicates inherent local system robustness, with respect to properties other than inertia. This definition by AEMO also adds that a system strength service represents a complex interaction of electrical and mechanical elements which support system stability, including, but not limited to, fault levels [45] and synchronising torque.[46][47]
- *ability of the power system to maintain the voltage waveform at any given location, with and without a disturbance* — this includes resisting changes in the magnitude, phase angle, and waveform of the voltage.[48]

AEMO's definitions, as outlined above, offer varying degrees of clarity as to what system strength relates to, and so what a service may consist of. For example, the first definition recognises impedance as an important factor, but does not include inertia.[49] However, the definition doesn't tell you about reactive power response or what factors beyond fault levels and synchronising torque could be included.

The second definition is unclear whether it includes the impact of voltage control devices and also more vague on whether inertia, primary frequency response and reactive power response[50] are included, in terms of their ability to help maintain the voltage waveform.

Therefore, the current NER use of three-phase fault level as a proxy does not necessarily provide a complete description of the service. It potentially fails to describe the nuances

45 Fault level refers to the level of current flowing as a result of a fault or a disturbance in the power system.

46 Synchronising torque is a form of electrical torque produced by synchronous generators when they rotate to generate electrical power

47 AEMO, Power system requirements, reference paper, p. 18, March 2018.

48 AEMO, Maintaining power system security with high penetrations of wind and solar, p. 22, Oct 2019.

49 Inertia is defined in Chapter 10 of the NER as: Contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is electro-magnetically coupled with the power system and synchronised to the frequency of the power system.

50 Voltage sensitivity may be reduced by the response of nearby voltage control sources such as generator automatic voltage regulators (AVR) and NSP devices including static Var compensators

associated with all aspects of the service, and could be considered to merely present a proxy measurement for the service.

The current NER definition of a system strength service also presents a perspective that the provision of fault current is the most appropriate and efficient method to address issues in areas of the grid with low system strength. It does not account for alternative ways in which power system security in low system strength environments might be maintained. For example, other ways in which the system strength requirements can be met include improving the tuning of control system responses.

Similarly, the Commission understands that "grid forming" (voltage source) inverters may have very different characteristics to the currently more common "grid following" inverters, in terms of the required fault level to maintain stable operation.

BOX 7: NON-SYNCHRONOUS INVERTER-BASED GENERATORS

The inverters of non-synchronous generators can be broadly classified into two different types - grid-following inverters and grid-forming inverters:

- **Grid-following inverters:** track the voltage angle of the grid to control their output. Most inverters currently connected in the NEM are this type of inverter. Grid-following inverters include PV inverters and wind turbine inverters. Grid-following inverter based generation use a phase-locked loop (PLL) control system to track the power system voltage and control the operation of the inverter to inject current into the power system at the same frequency as the system voltage. The PLL control system relies on a stable grid voltage to provide a reference for stable operation - the grid voltage may be less stable under low system strength conditions. Power systems with low levels of system strength can therefore result in unstable inverter operation.
- **Grid-forming (voltage source) inverter:** actively control their own output. Grid-forming inverters can create their own voltage reference and do not need a reference from the system. While grid-forming inverters have been used and proven for several decades in uninterruptible power supplies, and in microgrids international examples of the operation of grid-forming inverters in utility-scale power systems remains unproven.

Source: Power Systems Consultants, *Review of AEMO's PSCAD Modelling of the Power System in South Australia*, December 2017,p. 22. AEMO, *Power System Requirements*, March 2018, p. 15.

3.1.2 Providing system strength

Examination of the system strength service definition provides an understanding of the attributes of system strength that together contribute to power system stability, under system normal and disturbance conditions. This allows for consideration of whether the current definition supports the appropriate, effective and efficient provision of the service, or whether the current definition hinders or precludes any alternative options for how this could be provided.

While a more complete definition of system strength may outline the nature, scope, and description of the service with greater clarity, it is possible the definition may not differentiate between those elements of a security service that are measurable and may therefore be commoditised, and those that can't. Any definition of system strength therefore needs to be clear, to provide clarity in terms of what it is and so how it can be provided.

To that end, the Commission considers that this investigation should examine and seek consensus within industry as to what is a system strength service. This definition may be accompanied by additional definitions recognising how system strength can be procured passively and actively.

Table 3.1 outlines some ways in which system strength may be actively and passively procured in the NEM.

Table 3.1: **Technologies in the NEM that can contribute to meeting system strength needs**

SYSTEM STRENGTH CONTRIBUTION	SUPPLY SIDE	NETWORK
Active	Synchronous generators (1) Synchronous condensers (2) "Grid-forming", voltage source inverters	Synchronous condensers
Passive	Tuning non-synchronous generators.	Network augmentation (3) Tuning network voltage control devices

Source: AEMC, informed by AEMO, *Power system requirements, Reference paper*, March 2018, Figure 3 - Summary of required system services, and capability of technologies to provide them (p. 21).
Note: [1] Including generators with ability to operate in synchronous condenser mode. [2] Located on behind the meter on the supply side. [3] Partial or limited delivery.

This differentiation between active and passive contribution is a way of describing system strength that reflects the different kinds of technologies that can support system strength.

For example, synchronous machines like synchronous generators and synchronous condensers can be described as "actively" contributing to the maintenance of fault current levels and therefore system strength. This active "injection" of fault current reflects the intrinsic, physical response of these large, electro-mechanically coupled machines to the power system.

Alternatively, some non-synchronous, power electronic generators could be described as "passively" contributing to system strength, to the extent that they can tune their control equipment to operate stably in very low system strength (low SCR) environments.

Additionally, network augmentation can lower the impedance of the network and therefore positively contribute to the "passive" delivery of fault current from adjacent areas.

New technologies may also develop which can passively or actively contribute to system strength. All available procurement options for both passive and active system strength provision should be considered when designing a new system strength framework.

Therefore, the Commission considers that clarifying, and so amending, the NER definition of a system strength service is likely to contribute to broader options for the provision of system strength.

3.1.3 Sources of fault current

Noting the limitations of the term described above, available fault current at a specified location in the power system is currently can be used as a measure for system strength. Areas with higher levels of fault current indicate higher levels of system strength.

In the NEM, existing synchronous generators have historically been the primary sources of fault current, and therefore system strength. Synchronous generators typically provide three to four times as much fault current as inverter based generators. Other synchronous machines that can contribute positively to the total fault level include synchronous condensers and synchronous generators capable of running in synchronous condenser mode or large synchronous motors, such as a pump.

As outlined previously in Table 3.1, network augmentation (for example the installation of new transmission lines and interconnectors) can also increase the amount of fault current at a particular location from generators in other locations.

Inverter connected generators also respond to faults on the power system. However, in practice, the amount of additional fault current provided by inverter based non-synchronous generators is limited by the rating of the inverter[51] and is unlikely to be sufficient for correct operation of protection equipment.[52]

AEMO also describe that practical experience shows that the performance of non-synchronous generation may deteriorate in instances where new non-synchronous generators are placed in proximity to existing non-synchronous generators. Therefore, these generators are considered to effectively act as a "net detractor" for system strength.[53]

The impact that non-synchronous generators can have on the system strength of a system may be mitigated to a degree by these generators using better performing plant to reduce the system strength requirement as outlined previously in section 3.2.1.

In any case, AEMO does not include the fault level contribution of grid following generation technologies in determining the system strength requirements.[54] Conversely, non-synchronous generating systems that use grid forming technology may require less fault current, and can operate effectively at lower levels of system strength (low SCR). Therefore

51 Inverters can feed a fault at a level around 1.4 times rated current of the unit. This level will be specific to the manufacturer and may vary in the range of 1.1 to 1.5 times rated current of the unit. IEEE, Fault contribution of grid connected inverters, Electrical power conference, October 22-23, 2009, Montreal, Qubec, Canada.

52 The NER requires non synchronous inverter based generators to inject reactive power into faults as outlined in both the minimum access standard for capacitive current injection(S5.2.5.5(n)(1)(i)) and the automatic access standard S5.2.5.5(f)(1)(i).

53 AEMO, System Strength Requirements Methodology, July 2018, p. 17.

54 AEMO, System Strength Requirements Methodology, July 2018, p. 17.

they may be capable of providing a more "positive" contribution to meeting the system strength needs of the power system.[55]

The role of all current and future sources of fault current must be considered in how system strength is provided in the NEM.

3.2 Why system strength is needed?

Currently, system strength is a requirement of operating utility scale power systems.

Low levels of system strength can jeopardise the correct operation of generator and network protection mechanisms, as well as the stable operation of inverter-based plant, thus impacting system security. These impacts can occur as follows:

- A lack of system strength can mean that:
  - network fault clearance protection equipment does not operate correctly. This means that if a fault were to occur, there would not be enough fault current for protection equipment to correctly detect the fault and effectively isolate only the affected part of the network or may take longer to clear the fault which means generators may not ride through the associated disturbance. This could mean additional power system elements are isolated, potentially destabilising generators and, in the extreme a cascading failure.
  - inverter based generation may become unstable and disconnect, either during normal operation, or following a disturbance. As described in Box 7, certain types of "grid following", inverter connected, non-synchronous generation require a stable voltage waveform[56] from the power system to operate. In a low system strength environment, the voltage waveform may become unstable following even a relatively minor disturbance, and the inverter connected generators may struggle to successfully operate and remain connected. If multiple generators were impacted at the same time and trip off the system.
- Voltage management — low system strength could lead to more significant voltage step changes following shunt device switching, such as capacitor banks, which could breach system standards or result in general system instability.

Conversely, a strong power system will have high levels of fault current in response to the drop in voltage, which will reduce the effect of a fault on voltage in its vicinity.[57] That is, the higher the fault level, the better and more stable the response of the system to faults in that area. In the extreme, fault levels must be kept below the rating of equipment which is required to interrupt the fault current to isolate the impacted network element.

An appropriate level of system strength is therefore required for the power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance.

55 Ibid.

56 The 50Hz waveform of AC power systems.

57 AEMO, Fact Sheet System Strength, 2016, p. 1

It is possible to identify points in the network that are at greater risk of experiencing low system strength. These areas tend to be electrically distant from synchronous generation and may have a high concentration of non-synchronous connected generation.

The analysis required to determine fault level in MVA, and a non-synchronous generators required SCR, is relatively straight forward. However, analysing the stability and performance of multiple non-synchronous inverter based generators, requires using the detailed and complex power system analysis tool, such as electromagnetic transient (EMT) modelling.

3.2.1 Impact of inverter based generation on system strength.

Grid following inverter based generation use a phase-locked loop (PLL) control system to track the power system voltage and control the operation of the inverter to inject current into the power system at the same frequency as the system voltage.

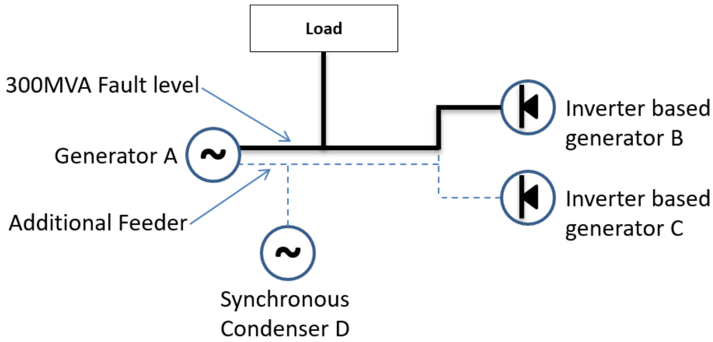
The injection of current by the inverter into the power system changes the voltage at the inverter and the PLL tracks this change and adjusts to maintain stable operation. However, at lower system strength the PLL, which tracks changes in the voltage, has the potential to go unstable.

For example, any perturbation in the current being injected creates too large a perturbation in the voltage at the inverter when the system has low system strength, resulting in the inverter operation becoming unstable. This effects quality of supply for other network users, can damage rotating machines, can affect the inverters fault ride through requiring the inverters to be disconnected. A current perturbation at one inverter will cause perturbations at all inverters in that part of the system.

As outlined previously, the short circuit ratio (SCR) is a measure of the relative system strength at the connection point and is calculated as the ratio of the fault level in MVA and the MW rating of the non-synchronous connected generation at the connection point. This may be represented as SCR is equal to the fault level (in MVA) divided by the generator's rating (in MW).

Figure 3.1 presents a simplistic model of a power system with a 300MVA fault level. The power system consists of a synchronous generator, a transmission line, a notional load and a non-synchronous inverter based generator.

Figure 3.1: Impact of inverter based generation on system strength



Source: AEMC

The purpose of the model in Figure 3.1 is to provide a simplistic illustration of the effect a connecting inverter based generator (connecting physically or electrically close to one another) can have on an system SCR.[58]

Furthermore, the model also illustrates, and this section further discusses, how a connecting generators SCR is impacted by network augmentation, the provision of fault current to the network by connecting a synchronous condenser and the effect of tuning inverter based generation to operate at a low SCR.

Calculating a generators SCR

In Figure 3.1 generator B is connected to the network which has a fault level of 300MVA. Generator A is pre-existing and is contributing to the fault level. Assuming generator B has a MW rating of 100MW, which will result in generator B having an SCR of 3.0.[59] Typically a short circuit ratio of 3.0 would be considered appropriate for stable operation. Generator B is unlikely to be constrained for system strength under normal operating conditions.

Connecting an additional inverter

If Generator C connects to the network, either physically or electrically close to generator B, assuming generator C also has a rating of 100MW, the resulting effect would be that the SCR for both generators would drop to 1.5.[60] In this example an SCR of 1.5 would typically be considered low and the potential for both inverters to experience stability issues would increase. Under the 'do no harm' framework an assessment would be undertaken to determine if Generator C is having an adverse impact on another connected participant. This may result in the requirement for Generator C to provide remediation which would alleviate

58 It is important to note that while SCR serves as a good proxy or screening tool for potential stability issues it does not replace complex power system modelling.

59 SRC = 300MVA Fault current / 100 MW rating.

60 SRC = 300 MVA Fault current / 100 MW rating + 100 MW rating of newly connected inverter

the impacts on the pre-existing participant. In the absence of remediation constraints would be applied to C to alleviate the impacts on the pre-existing participant (Generator B) and maintain power system security.

Actively contributing to fault current

A synchronous condenser D could be connected to the network, assuming it has a 100MVA rating equating to an approximate 300MVA contribution of fault current, the resulting effect would be that the total fault level would be raised from 300MVA to 600MVA. This would in turn have the effect of raising the SCR for both inverters to 3,[61] improving both generator's B and C operating stability. Under the "do no harm" framework provision of this remediation would be required from Generator C.

Passively 'contributing' to fault current by reducing system strength requirement (network augmentation)

If an additional feeder line is connected to the network instead of synchronous condenser D and this notionally has the same impedance as the existing network line, it would have the effect of increasing the fault level on the network from 300MVA to 600MVA. This would in turn have the effect of raising the SCR for both inverters to 3.0[62] and improving both generator B and C operating stability.

Passively contributing to fault current (Tuning inverters)

If generator B and C are connected to the network and both are assumed to have a low SCR of 1.5, both generators could opt to tune their inverters to operate in low system strength conditions. This would reduce the potential for both generators to experience stability issues. In this scenario, no additional fault current would be required to improve generator stability issues.

Grid-following inverter-based generation effectively acts as a net detractor for system strength. The reduction in a non-synchronous inverter based generators SCR, described in the previous examples, represents this "net detraction" effect. As more and more inverter based generation connect electrically or physically close to one another, the effect of this impact is exacerbated. This section has outlined some options that exist to remediate areas of the grid experiencing low system strength.

Non operation or retirement of synchronous generation

Due to commercial or physical considerations, Generator A may not operate in the power system or may retire. Under the 'minimum system strength' framework this could likely result in AEMO declaring a system strength shortfall.

This would place an obligation on the TNSP to procure the provision of system strength to the required minimum level as a prescribed service under the transmission network economic regulatory framework. This service could be provided by any of the passive or active

61 SRC = 300 MVA Fault current + 300MVA Synchronous condenser fault current / 100 MW rating + 100 MW rating of newly connected inverter

62 SRC = 300 MVA Fault current + 300MVA Feeder fault current / 100 MW rating + 100 MW rating of newly connected inverter

arrangements and would be assessed economically for a least cost solution in accordance with the AER's RIT-T.

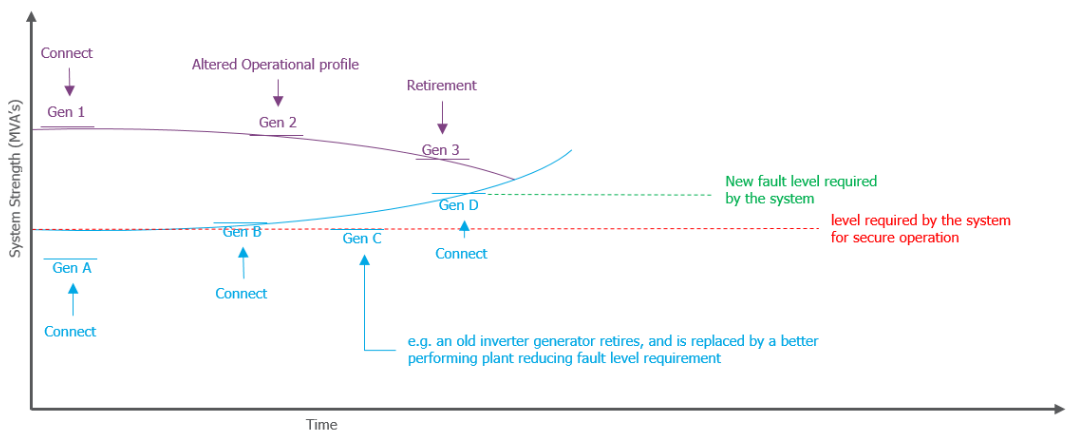
3.3 The provision of system strength in the NEM

System strength in the NEM has predominantly been provided as a by-product, when energy is produced by large synchronous generators, and was historically abundant in many parts of the network. The current frameworks have led to the establishment of essential levels of system strength, as discussed in Chapter 2. The intent was to make sure there is sufficient system strength in the power system to maintain secure operation.

This section describes the interaction between the declining provision of system strength in the NEM and, as described in section 3.2.1, the system strength requirements of newly connecting non-synchronous generators either electrically or physically proximity to each other.

Figure 3.2 presents a conceptual overview of the interaction between generators that provide system strength alongside the system strength levels required by inverter connected, non-synchronous generation for stable operation.

Figure 3.2: Provision of system strength



Source: AEMC

Figure 3.2, presents some drivers behind a declining trend in the provision of system strength over time, including:

- Synchronous generators (presented as Gen 1-3) are represented by a purple trendline. Overall, they negatively contribute to the provision of system strength over time due to retirement and reduced patterns of operation. The provision of system strength may decline as a result of synchronous generator retirement or the displacement of synchronous generation by non-synchronous generation in the wholesale market.

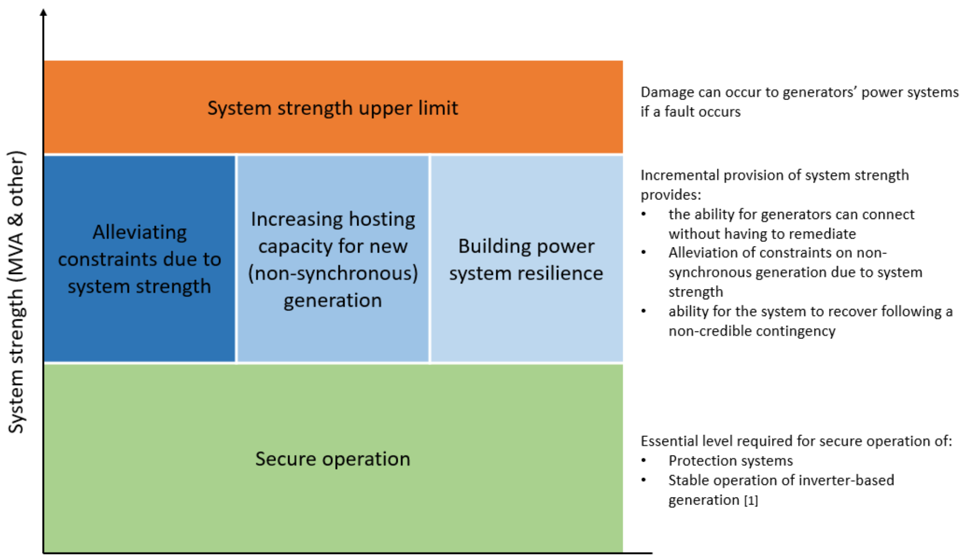
- Non-synchronous generators (presented as Gen A-D) are represented by a blue trendline. They increase the essential fault level system requirement over time as more inverter connected generation connects (described in section 3.2.1). Non-synchronous generation typically require an essential system strength level at their connection point to maintain stable operation (in normal conditions) and following a credible contingency event.[63] Therefore, the essential system strength level required to maintain a secure and reliable power system is likely to increase in network areas with growing non-synchronous generation connection.

Neither the current minimum system strength framework nor the "do no harm" framework support the provision of system strength beyond the levels required for stable operation. Therefore, any new system strength framework should have consideration of the drivers that contribute to both the declining provision of system strength in the NEM, alongside the increasing system strength requirements of newly connecting non-synchronous inverter based generation.

3.3.1 System strength thresholds

The provision of system strength can provide various system benefits. This ranges from supporting system security, removing constraints on dispatch, and "freeing up" network capacity for new generation investment. Figure 3.3 provides a conceptual overview of the various "thresholds" of system strength might be described.

Figure 3.3: Threshold levels of system strength



Source: AEMC
Note: [1] Does not include inverter-based generation which were required to implement system strength remediation schemes under the system strength framework.

63 AEMO, System Strength Requirements Methodology, p. 12, July 2018.

In Figure 3.3, the system strength thresholds shown are:

- **Essential level required for secure operation:** this essential security system strength level in turn refers to fault current required for network and generation protection systems to operate correctly, including voltage control system stability (e.g. SVC and switched reactive banks).
- **Alleviating system strength constraints in the network:** when available fault level is low in the system, it may become necessary to curtail non-synchronous generation output. It follows that increasing available system strength may allow for these system strength constraints to be removed.
- **Increase the hosting capacity for the network:** this would be a level of system strength at which new connecting generation would not have to remediate their impact on the operation of the power system or other participants. Increased availability of system strength may also contribute to hosting capacity by supporting faster and less complex coordination of multiple non-synchronous generation connections.
- **Provide a resilience margin:** the levels of system strength procured that provide an additional margin that may help stabilise the system following more severe non-credible contingencies.
- **System strength upper limit:** the system strength upper threshold reflects the maximum fault level rating of the transmission lines and substation equipment in that part of the network. Clause 4.2.2(e) requires that the configuration of the power system is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment.

The boundaries between these aspects, and the order in which the contributions are made, do not necessarily reflect what increased volumes of system strength does in practice. For example, volumes of system strength above the essential level may contribute to increased resilience, to the extent that this system strength is not "used up". That is, it is not used to relax system strength constraints on non-synchronous generation in the short term, or to provide hosting capacity in the longer term, both of which would reduce the available margin.

This effect may be relevant to how system strength is procured, in that both types of benefits can be measured and accounted for when considering the long run value of procuring a given level of system strength.

Sufficient system strength is a condition precedent for the secure operation of the system *and* being able to meet consumer demand for energy generated by non-synchronous machines. Thus, as part of the transition of generation mix which is occurring, the provision of system strength beyond current essential levels required for stable system operation will move from being a necessary service to being a question of economic benefit.

Procuring the essential levels

System strength is a critical security service. Not having the essential system strength level can mean that the system strength is not sufficiently high to keep the remaining generators stable and connected to the power system following a major disturbance. The relative stability of the power system can also reduce when additional non-synchronous generators connect.

Under current arrangements, generators that contribute to the minimum level are only compensated for their provision of energy. A separate compensation mechanism does not exist in the NER to compensate generators for their contribution to minimum system strength level.

The attributes of system strength, as discussed in the next section, can greatly influence the ways in which you plan for, procure, price and pay for both the essential level of system strength required in the power system and quantities above the essential level. Because of this, it may be possible that different approaches could be used for the provision of the essential level and those levels above it. This is discussed further in Chapter 4.

Procuring above the essential levels

Providing system strength above the base level will require consideration of the trade-off between the cost of providing additional system strength and the provision of market benefits through the release of constraints on the network, reducing the complexity of the connection process and "freeing up" capacity on the network to allow connection of more generation capacity.

Currently, there is no framework by which to value the provision of system strength (or inertia) above the base levels for system security/stability.

The Commission has received a rule change request from Hydro Tasmania which proposes to address this issue by integrating the dispatch of a "synchronous service" with the existing energy and FCAS spot markets.[64]

The rule change request aims to provide compensation to synchronous generators who are willing and able to provide a synchronous service to the market, incentivising generators that were previously disincentivised from providing their services. For example generators would be disencentivised from providing energy under conditions where the energy price is lower than their cost, and they cannot set the spot price. The proposed rule change seeks to address this by providing a separate source of revenue for synchronous generators.

The proposal aims to find the optimal combination of reduced energy cost, by optimising the benefits of relieving constraints on non-synchronous generation, against the cost of sourcing the synchronous service from the synchronous service provider. This is similar to the decentralised, co-ordinated options as set out in the next chapter, in section 4.3.

Furthermore, the costs of such an approach may change over time as changes to the NEM dispatch engine and alternative market arrangements are contemplated.

64 See: https://www.aemc.gov.au/rule-changes/synchronous-services-markets.

BOX 8: CASE STUDY: ALLEVIATING CONSTRAINTS DUE TO SYSTEM STRENGTH

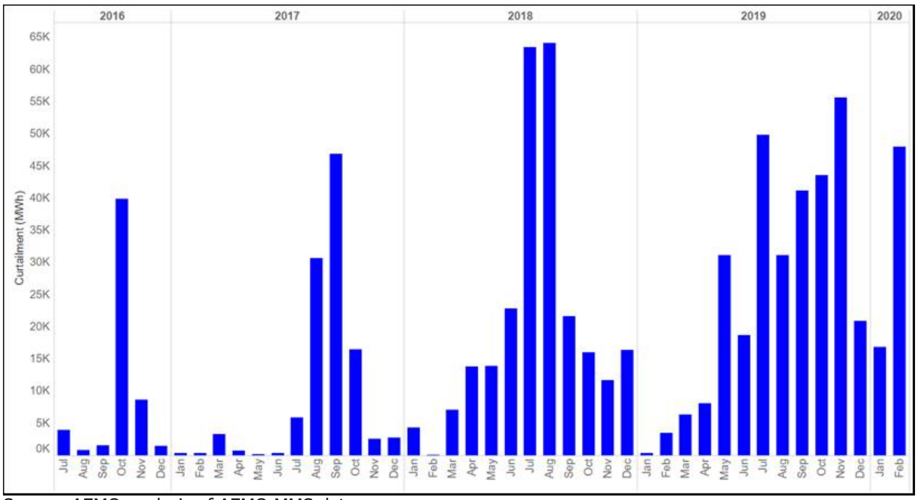
As shown in Figure 3.3, there is value in the incremental provision of system strength above the essential. One such case is providing additional system strength to alleviate constraints - a case study of this potential value is explored below.

Low system strength is leading to the output of some existing non-synchronous generators in the NEM being curtailed. This has occurred in South Australia in recent years, as a way of managing the low levels of system strength that have affected that region.

This curtailment provides a demonstration of the kinds of impacts that a lack of system strength can have in terms of constraining dispatch of non-scheduled generation. Equally, it illustrates the kinds of benefits that may accrue if these constraints are relieved through the provision of increased levels of system strength, by allowing for increased production of energy from non-synchronous generators. This demonstrates how generation could potentially be 'unlocked' through the provision of additional system strength above essential level.

The analysis below examines the volumes of non-synchronous wind generation curtailment that has occurred in South Australia in recent years. To do this, the curtailed generation volumes resulting from substantial and ongoing system strength constraints for wind output in South Australia was analysed. This analysis assumes that the lack of system strength services is the sole basis for the existence of these constraints.

Figure 3.4: Total wind curtailment in South Australia, monthly July 2016 - February 2020



Source: AEMO analysis of AEMO MMS data

The figure above shows:

- The high point was in August of 2018 when 64 GWh of wind was curtailed in one month, equivalent to a constant curtailment of 86 MW.

- In total, 798 GWh of wind have been curtailed over the last three and a half years due to low system strength conditions in South Australia.

3.4 Attributes of system strength

This section outlines the key attributes of system strength. Understanding these physical attributes is necessary to understand the challenges and trade-offs that must be taken into account when considering a new framework for sourcing system strength.

These attributes are relevant to considerations of how to plan for, procure, price and pay for system strength, and underpin the various options for these market design questions considered in the next chapter.

3.4.1 Binary, lumpy nature of system strength

Currently, the largest contributor to system strength in the NEM are synchronous machines (predominantly synchronous generators and synchronous condensers). A synchronous generating unit that contributes system strength to a system does so by virtue of the generating unit being online, synchronised to the grid and providing either energy (active power), or running in synchronous condenser mode.

Importantly, once the generator is contributing to the provision of system strength, this contribution represents the entirety of its system strength capability. The provision of system strength by a synchronous machine is determined by its physical design and nameplate rating. It is also not proportional to the MW output of the generator providing the service. No matter what the unit's operating state, once it is synchronised to the grid it will provide all of its system strength contribution at once. This is also regardless of whether the unit is producing active power or running in synchronous generator mode.

This physical attribute means that the provision of system strength from synchronous machines cannot be procured in an incremental manner. Instead, it is dependent on a generating unit's ability or willingness to commit. That is, it depends on whether the unit is synchronised, or not; it either provides system strength, or it does not. For this reason system strength may be referred to as 'lumpy', as the service is provided in full by closing a synchronous generator's circuit breaker and synchronising to the grid.

Binary nature of system strength

Additionally, the requirement for adequate levels of system strength to the essential level for the secure operation of the power system can be described as being a "binary" requirement. That is, the power system either has enough system strength to be secure, or it doesn't. Power systems require essential levels of system strength to operate correctly as outlined in section 3.2.1.

Insufficient levels of system strength will result in an insecure power system, operating in an unsatisfactory state.[65] Therefore, system strength must be maintained above the essential levels required for system security. As the provision of system strength must be maintained at all times, it's provision as a service may be considered to be binary.

Implications for a system strength framework

The binary and lumpy attributes of system strength have a number of implications for how a mechanism for sourcing system strength might be designed. In particular, challenges may exist in terms of unit commitment, the locational specific nature of the service, the limitations within NEMDE and its effects on competition.

These attributes, combined with the potential for limited competition existing among system strength providers, may result in system strength being a service with inherent monopolistic characterises.

The lumpy, binary nature of system strength also has implications for how compatible this service would be with generating efficient marginal price signals. This may be compounded to the extent that provision of system strength is locationally specific.

The non-linear nature of the provision of system strength also has implications for the dispatch of the service. For example, current limitations of the NEM dispatch engine (NEMDE) may present some challenges in terms of creating efficient price signals for a system strength service, due to the difficulties in formulating constraints for a service with such attributes - this is explored in further in Chapter 4.

Additionally, a mechanism would also have to take into account limitations about how fast synchronous machines are able to commit and de-commit. These considerations may change in the future as the ESB's market design reform work progresses.

The lumpy nature of system strength has implications for preserving the essential system strength requirements necessary to maintain system security. For example, some combinations of those generators may rely on one particular generator where multiple synchronous generators are needed to provide essential levels of system strength to ensure the essential level is being preserved. This attribute could compound any potential market power issues.

3.4.2 Unit commitment issue

In any electricity system, decisions need to be made ahead of real time to start (or stop) individual generating units. The decision, depending on generation technology, may need to be made many hours in advance of the need to produce energy and/or associated system security services, and may have significant cost. This decision is known as the "unit commitment decision".

In the NEM, the unit commitment decision is, in effect, taken by individual market participants on the basis of expected energy (or FCAS, secondary contract) market revenue.

65 An unsatisfactory state within the power system can result in the maloperation of controls, overheating of motors and tripping of generators and other equipment.

This unit commitment decision of individual generators is distinct from the dispatch process undertaken by AEMO. However, having some visibility of a generating unit's commitment is important to maintain system security. This is to make sure that the right resources are available at the right time to ensure co-optimisation of necessary resources and services.

Currently there is no ability for a market signal or interventions by AEMO to adjust the levels of system strength, as provided by existing generators, in real time. Instead, system security relies on the physical commitment of synchronous plant ahead of time. To address this, AEMO currently assesses the commitment of synchronous generators in pre-dispatch and directs as necessary to maintain essential levels of system strength in South Australia.

Implications for a system strength framework

The Commission understands that, to date, it has not been possible to fully integrate system strength limits into NEMDE in the same way as other kinds of system limits, such as thermal, voltage or other stability limits. This is on the basis that it is a lumpy, binary service, which makes it difficult to formulate NEMDE constraints so that the correct combination of synchronous generators are brought online.

These limitations are further complicated by both the locational characteristics of system strength and the second order effects on non-synchronous generation dispatch. There would also be extensive amounts of EMT level power system simulations required to underpin the development of system strength related constraint equations.

In light of these emerging security concerns in the NEM, including the use of directions to ensure system strength in South Australia, active consideration is being given to the development of ahead mechanisms to support system security requirements.

Near term activities are currently being considered by the ESB with longer term solutions being part of the ESB market design reform work.

3.4.3 System strength services are relatively locational-specific

The system strength at any given location is primarily determined by the number of:[66]

- synchronous machines nearby that are capable of injecting fault current
- transmission lines or distribution lines (or both) connecting synchronous machines to the rest of the network.

The system strength requirements of certain parts of the power system may only be able to be met by one or two select synchronous generators.[67] This may be particularly the case in fringe areas of the grid and is exacerbated if there is also high penetrations of non-synchronous generation.

66 AEMO, System strength requirements and fault level shortfalls, p. 11, July 2018.

67 For example, AEMO's recently published Transfer Limits Advice for system strength highlights that at least two Loy Yang units must be online in each of the 33 combinations of synchronous generators that are required to maintain essential levels of system strength in Victoria. A similar situation occurs in South Australia, where Torrens Island power station plays a key role in providing system strength.

This localised attribute of the provision of system strength may create difficulties in terms of sourcing system strength, where the greatest need is arising. This could in turn present difficulties in competitively procuring the service, due to the potential market power of some system strength providers.

The location-specific characteristics of system strength therefore have several implications for how the service is procured. These implications are explored in more detail in Chapter 4.

Generator combinations and system strength constraint management

The locationally specific nature of system strength means AEMO must currently determine specific combinations of synchronous generators that must be online for secure operation. AEMO has provided, through its transfer limit advice reports, information about the levels of system strength required to securely operate in regions of the NEM with high levels of non-synchronous generation.[68]

AEMO is responsible for enabling the 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. Where TNSPs are unable to procure the required fault levels to enable AEMO to maintain power system security, AEMO may use other operational measures to maintain adequate system strength.

This has historically included issuing directions to ensure required combinations of synchronous generators remain online at all times, and constraining the output of non-synchronous generators. Until ElectraNet finalises the commissioning of synchronous condensers in 2020, this approach is being used by AEMO to maintaining sufficient system strength in South Australia.[69]

This reliance on specific generator combinations means that the value of an individual generator's system strength can be influenced by the combination of all generators online at any given moment. This makes it difficult to discreetly value the provision of an individual generators' contribution in isolation.

The value of a generator providing a service will be determined by the physics of the power system. For example, a generator contributing to system strength will have value as long as it fits within a viably dispatchable combination for secure operation as determined by AEMO. However, in the event that any generator removes itself from dispatch, a different generator combination may be required and may see contributions from previously valued generators no longer being needed.

This attribute of system strength, namely that it can currently only be provided by specific combinations of synchronous generators, is a factor that would need to be considered in developing a future-proof mechanism for the procurement and pricing of system strength. It

68 AEMO, Transfer Limit Advice - South Australia System Strength, Dec 2018.

69 More details on AEMO's current operational requirements for system strength can be found in AEMO's Transfer Limit Advice - System strength, September 2019, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-South-Australian-System-Strength-v20.pdf

also suggests that a flexible framework should be developed that can accommodate different technologies as they evolve.

3.4.4 Interactions with energy and other security services

Interactions with energy provision

A key challenge associated with sourcing a system strength service relates to the way that the service can be valued. As described above, some of this complexity relates to the lumpy nature of system strength. An equally important attribute of system strength is the extent to which it can be provided by synchronous generators, as a service that accompanies the production of energy. This may create issues for the design of any future mechanism for sourcing system strength, as there are likely to be a number of complex interactions between provision of the system strength service and energy.

Synchronous generators provide system strength by virtue of being online and providing energy into the energy market. With exception to hydro plants, most existing synchronous generators are not able to operate their units in synchronous condenser mode. This means that the system strength provision by most large synchronous generators in the NEM comes with the provision of energy. Therefore, synchronous generators have to run at minimum generation levels or above to provide system strength, which may involve high levels of energy output for large synchronous units.

Additional sources of system strength are often most needed when there are large amounts of non-synchronous generation online, which often translate to those times when energy is abundant and prices are very low. Running synchronous generation for the purpose of providing system strength is likely to inject energy into the power system and may impact on energy prices, potentially, depressing them.

Additionally, the coupling of energy with system strength provision from synchronous generators also currently causes issues when there is no operational demand to meet. For example, in the middle of the day when there are high levels of rooftop PV operating, there may be less need for synchronous generators to be online other than to provide fault current.

As AEMO identified in its submission to the *Investigation into intervention mechanisms and system strength* consultation paper: "Solutions relying on the dispatch of synchronous generation will not be feasible when most or all load is being served by rooftop PV".[70]

Conversely, the costs of providing a system strength service do not currently have to take energy market considerations into account when it is being provided by a synchronous condenser, a synchronous generator operating in a synchronous condenser mode, or some other technology. These technology options may avoid complex interactions with the energy market as described previously.

Additionally, network options for the provision of a system strength service provision should be considered in regions of the power system where system strength services cannot be

70 AEMO, submission to the *Investigation into interventions mechanisms and system strength* consultation paper, 23 May 2019, p. 11.

procured from existing generators at reasonable cost, or where existing generators are not located such that they can physically do so.

Implications for a system strength framework

A frameworks' design to value system strength must take account of the impacts of the inability of certain participants to physically decouple energy from the provision of system strength.

Furthermore, considerations of the impact that periods of low operational demand and the behaviour of synchronous generators during periods of low pricing have on valuing the provision of the service. It will also be important for the framework to be technology neutral and flexible to take account of emerging technologies that could provide system strength.

Interactions with other security services

The following section explores possible opportunities to co co-ordinate the provision of system strength services with other system security services. This includes a discussion on the challenges in valuing the services, and examines opportunities for the co-ordination of security services.

The provision of one service may come with the co-benefit, or in some cases the detriment, of others. As a number of system security services are physically interrelated, opportunities may exist to co-optimise the provision of some services. Capitalising on these opportunities efficiently can result in improved economic operation of the power system and savings for consumers.

The Commission concluded in the *System Security Market Frameworks Review* that the best mechanism to meet the essential inertia requirements associated with maintaining system security would be through provision by TNSP's. The Commission cited one of the advantages of this approach being the ability to co-ordinate inertia provision with the more locational requirements of maintaining system strength.[71] Further to this, opportunities may exist for the coordination with other essential system security services, particularly reactive power support.

Considering the interactions between services, and so coordinating the provision of these services, will assist in minimising the overall costs to consumers. By contrast, there would be a greater likelihood that separate assets would be constructed to address frequency and system strength individually if different entities were given responsibility for procuring these services. This may result in increasing the overall cost to consumers.

South Australia case study — system strength and inertia

As experience in South Australia has shown, there are already potential opportunities to co-ordinate the procurement of system strength and inertia services. For example, when investing for the provision of fault current (where the source of fault current can also provide inertia) the TNSP can consider the interaction with any obligation to provide inertia under the

71 AEMC, System Security Market Frameworks Review Final report, June 2017, p 33.

minimum inertia framework (due to the shortfalls being declared around the same time). Meeting the essential required levels of inertia and system strength in a co-ordinated manner should be an inherent part of the TNSP's planning processes.[72]

ElectraNet is installing synchronous condensers to maintain system strength in South Australia. After AEMO declared an inertia shortfall in December 2018, ElectraNet opted to add flywheels to the synchronous condensers. This allows it to simultaneously address the shortfalls in both system strength and inertia. This co-optimisation can leverage the capital expenditure assigned to the provision of system strength to provide an additional security service at a low marginal cost, increasing the economic efficiency of the delivery of inertia in areas where shortfalls are declared.[73]

Where the declaration of different security service shortfalls does not coincide, there would be value in undertaking some form of sensitivity analysis. This would attempt to identify whether a shortfall in a related service is likely to arise in the mid to longer term.

In such cases, there may be value in adopting a "readiness strategy" or "option value approach" such as installing a synchronous condenser to which a flywheel can fitted later, rather than one that does not allow for later retrofitting. Such an approach can deliver efficiencies and avoid missed opportunities that result in higher costs to consumers.

Implications for a new framework

Efficiencies could potentially be realised by adopting an approach that includes undertaking long term planning and proactively identifying and procure security services needed over the mid to long term.

By contrast, a more limited planning horizon (such as five years) could result in such opportunities being missed. In the mid to longer term, technological innovations may enable the delivery of new services to support existing services.

72 AEMC, System Security Market Frameworks Review Final report, June 2017, p. 90.

73 Other examples of co-optimsation may exist. AEMO has identified a number of opportunities for the application of fast frequency response (FFR) to complement existing frequency control services. For example, emergency response FFR is being implemented as part of the special protection scheme under development to protect against or prevent the loss of the Heywood interconnector connecting South Australia to Victoria. See: AEMO, *Fast frequency response in the NEM, Working paper - Future power system security program*, 2017, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Working-Paper---Final.pdf

4 EVOLVING SYSTEM STRENGTH FRAMEWORKS

BOX 9: SUMMARY OF KEY POINTS

- The Commission's approach to its review of the system strength frameworks is centred around how system strength can be **planned** for, **procured**, **priced** and **paid** for. We consider this provides a structure for assessing different system strength models.

1. **How to *plan for* the service? —** the process for determining how much system strength is needed and provided in the system over different timeframes. There are two key timeframes that need to be considered: 1) the long-term, particularly given the transition to a power system with high volumes of non-synchronous generation — consideration needs to be given as to how far in advance (i.e. how many years) do we plan; 2) the short-term, with system strength levels potentially varying depending on what is happening on the system at a particular point in time.
2. **By what mechanism(s) is the service *procured*? —** the process for sourcing necessary volumes of system strength, which has implications for how the service is priced.
3. **How is the service *priced*? —** the process for determining how system strength is valued and priced.
4. **Who *pays* for the service? —** the process of determining which parties should bear the cost of providing the service.

- The Commission has used this approach to map out four high-level framework models that could be used to source needed volumes of system strength. Importantly, each of these models are not mutually exclusive, and elements of each may be combined together to create hybrid models. For the purposes of facilitating discussion, they are grouped into four general models.
    - **Model 1: Centrally co-ordinated:** would aim to co-ordinate and plan the grid into the future to provide needed system strength over the medium to long term.
    - **Model 2: Market-based / decentralised:** would utilise dynamic, shorter term procurement of system strength with market price signals. This model could include mechanisms to co-optimise system strength services into energy dispatch, or some other competitive procurement mechanisms, such as contracting, to co-ordinate with other system services in the shorter-term.
    - **Model 3: Mandatory service provision model — generator provision obligation:** describes a centralised approach, with an "active" obligation on all generators to actively supply a given level system strength.
    - **Model 4: Access standard model — generator performance obligation:** describes a "passive" obligation on generators whose connection to the grid would be conditional on having equipment that enables them to operate in low system strength

environments. This model would not require any active volume of system strength (fault current) to be provided, in contrast to the model above.

This chapter explores at a high-level the different models that could be considered (either all or in part) to evolve the NEM frameworks for the provision of system strength.

The Commission has developed an approach to assess these different models. Broadly speaking, this framework considers how system strength can be **planned** for, **procured**, **priced** and **paid** for. This provides a structure that can be used to shape our thinking when assessing options for providing system strength.

From this, four coherent models for how system strength can be provided have been described. Each model combines a range of ways in which system strength can be planned, procured, priced and paid for. These models are not intended to be mutually exclusive. Rather, they set out a spectrum of design options for regulatory frameworks to provide system strength. They are designed to be flexible to a range of different future outcomes, and to developments in technology solutions for providing system strength.

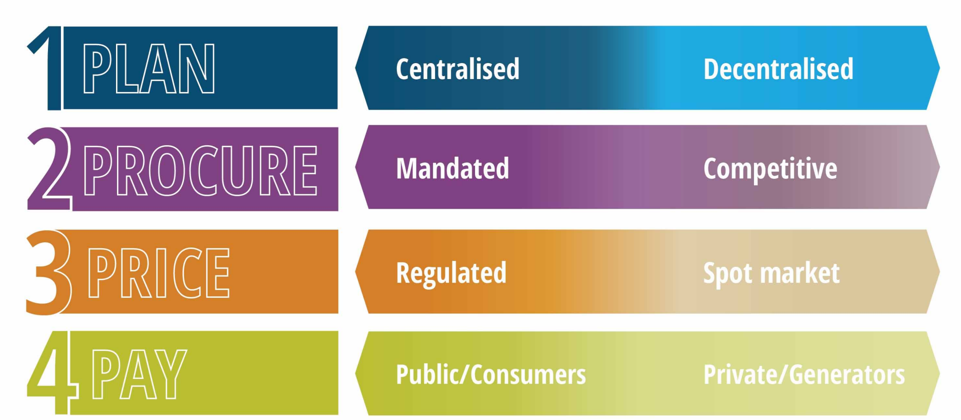
The Commission encourage stakeholder feedback on whether specific models - or combination of models - are likely to represent an optimal solution.

4.1 Approach to developing a new framework

The Commission's starting point in thinking about new regulatory frameworks is to consider how system strength can be **planned** for, **procured**, **priced** and **paid** for.

These concepts are explored in the following sections. The concepts described below are intended as a general guide to how regulatory frameworks for provision of system strength might be designed.

Figure 4.1: Approach to developing framework changes



Source: AEMC

4.1.1 1. How to *plan for* the service?

This is the process for determining how much system strength is needed and provided in the system over different timeframes, from the short-term to the long-term.

The Commission is giving particular consideration as to how system strength can be planned for over the long-term. A power system cannot operate below the essential system strength level - it is necessary to have this system strength available at all times to support the safe and secure operation of generators and the power system generally. Having enough system strength over the longer term is therefore essential to support the changing generation mix and transition that is underway.

Planning for system strength provision over the longer term means thinking about how much system strength is needed to operate the system securely, as well as how to facilitate efficient levels of investment in new generation capacity, in order to promote the long-term interests of conumers. This will require some form of planning for the coordination of this system service and potential co-optimisation with other security services.

Planning can be done over different timeframes, and using more centralised or decentralised approaches. Under current NEM frameworks, a combination of more centralised and decentralised approaches are used:

1. In the long-term, investment and retirement of the provision of energy is not centrally planned — that is, there is no formalised central coordination of where and when generation investment should occur. However, investors use information about various inputs (such as projections of congestion, loss factors and land availability) to inform temporal and locational investment decision-making.[74]
2. In the short-term, more centralised approaches are used, given how much is required depends on operational conditions. For example, the current provision of some security services is determined through a centrally planned and co-ordinated process, such as the processes for sourcing FCAS, SRAS and NSCAS — although each framework has a different degree of centralisation.

The above demonstrates how both centralised and decentralised approaches are capable of supporting some form of coordination. In some cases, a centralised approach may be necessary where there is less room for error in the coordination process. For example in the operational procurement of services critical to the safe and secure operation of the power system.

Current arrangements also demonstrate how decentralised and more centralised approaches can complement each other, particularly over different timeframes. As described above, currently, given the criticality of sourcing adequate security services in the operational timeframes, a more centralised approach is used, which complements the decentralised approach that delivers investment in capacity to provide these services, over the longer term.

74 The Commission is currently progressing its Coordination of transmission and generation investment (COGATI) review, which considers reforms to improve the locational signals that are provided to participants, by providing them more information to factor into their investment and retirement decisions, improving the coordination of this planning.

There are also costs associated with planning. As planning depends on forecast expectations of the future, any error in these forecasts can result in inefficient outcomes. Over-reliance on forecasts, or a failure to account for the risk of error in forecasts, can result in poor decisions and inefficient outcomes, the cost of which are borne by customers. Decentralised coordination minimises the risks of this, given that multiple parties are making decisions based on different information.

There are many issues related to the planning and coordination of system strength, including:

- The difficulty of accurately forecasting system strength needs over a longer time horizon, which makes a process of planned coordination difficult.
- On an operational timescale, coordination is also necessary to maintain system security, by procuring enough system strength to avoid major outages.
- Some planning and coordination of the connection of generators is becoming increasingly necessary, to avoid instabilities that can arise due to unpredictable control system interactions in a low system strength environment.

When considering planning for services, it is necessary to think in terms of how changes in technology may drive long term trends in the power system. In particular, the emergence of new technologies can change the way that a service is supplied, but may also change the demand for the service. "Grid forming" (voltage source) inverters coupled with battery storage is one such example of technology changes that may impact on the provision of, and need for, system strength services.

4.1.2 2. By what mechanism(s) is the service procured?

This is the process for sourcing the necessary volumes of system strength, which have implications for how the service is priced.

As with planning, there are various approaches to procurement that exist along a spectrum, ranging from regulated approaches to a more market based approach:

1. At one end of the spectrum is a more regulated approach, which could include mandating provision from all generators or regulated provision by NSPs.
2. At the other end of the spectrum, some form of competitive approach could be used. There are again a number of options about how the service is provided, for example,
   a. the service could be procured through mechanisms such as a competitive tender process, which could result in long term bilateral contracting or shorter term tender processes;
   b. the service could be provided through a fully open-market approach, with the service procured close to real time on a marginal / incremental basis.

There are two key complexities associated with the procurement of system strength, as discussed in Chapter 3:

1. The binary, "lumpy" nature of the service; it is either not provided, or provided as a large, single volume. This can make real time, market based approaches to procurement more

complex, as the service cannot easily be broken down into increments and easily subject to marginal pricing.

2. The provision of system strength by most synchronous generators also impacts the provision of energy (MW). This therefore suggests that there is a need to consider the interactions between the energy market and the provision of system strength. Distortions and unintended feedback interactions may be created in either market, if not carefully managed.

Additionally, the level of system strength to be provided by each model is important to consider. As discussed in Chapter 3, the provision of system strength can be thought about in terms of being above and below an essential level. This level is required for keeping the system in a safe and secure operating state, and levels above this can deliver a "market benefit", such as unlocking constraints on dispatch or facilitating new investment. It may be that system strength provided to meet these different "levels" is more effectively procured by different models. It is important to make clear distinctions between these essential and market benefit levels, as well as the different models associated with each, while also effectively co-ordinating them under a single, internally consistent framework.

4.1.3 3. How is the service priced?

This is the process for determining how system strength is valued and priced.

Pricing approaches can extend from regulated pricing, to a competitive approach (where prices are determined in a decentralised manner through a market approach or through a competitive tender process). The specific mechanisms for pricing services should also reflect the way the service is planned and procured. It may also include different components, such as fixed and variable components, and may be based on a global, or a localised need.

Pricing of a service also reflects the value attached to the service. Regarding system strength, this could be on the basis of (or a combination of) how its provision provides:

1. supports system security and resilience, which suggests its value and price can be measured against avoided loss of load.
2. reduces constraints on dispatch, facilitating more efficient investment over the long term, which suggests valuation could be on the basis of increased supply of megawatts (MWh) to consumers.

Additionally, the price of the service could reflect the cost of providing the service. That is, the associated long and short run marginal costs of operating units that provide system strength could also form the basis to price system strength. This may be difficult due to the large spread of these costs between the different potential market providers of the service - such as gas, coal, hydroelectric generators, as well as synchronous condensers.

There are two key complexities associated with the pricing of system strength, as discussed in Chapter 3:

1. As with procurement, the lumpy / binary nature of the service makes it hard to price on a marginal basis. This can create complexities for taking a fully co-optimised approach

between energy and system strength, as the provision of lumpy system strength may not integrate well with the incremental, marginally priced supply of megawatts.

2. Due to its largely localised nature, system strength can potentially be subject to a degree of market power. Where there is a single provider of the service, and no realistic threat of entry from a competitor[75], then the provider will likely face strong incentives to price along the monopoly supply curve. Some form of regulatory intervention may be necessary to set an efficient price in such situations.

4.1.4 4. Who pays for the service?

This is the process of determining which parties should bear the cost of the service.

There are different ways to think about how this can be done, but the four main factors to consider are who:

1. benefits from the provision of the service
2. causes the need for the provision of the service
3. is best placed to respond to any price signals generated by the framework's
4. is best placed to manage the risk associated with the cost of the service

This again has interactions with the above considerations. While consumers ultimately pay for all costs in the energy market, it is worth considering who is best placed to manage the risks associated with the cost of the service.

All of these factors will be relevant in determining how the costs of providing the service are recovered. There are multiple examples in the existing NER frameworks of mixed approaches. This includes where some portion of the cost is borne on the basis of which parties cause the need for, or benefit from, the provision of the service, as well the extent to which they can respond to the allocation of these costs.[76]

The question of who pays for system strength will be closely linked to the selected method of valuation and pricing. That is, if the primary value, or benefit provided, of system strength is:

1. Enhanced security and resilience, it may follow that consumers are the primary beneficiaries, through avoided unserved energy (USE).
2. Relief of constraints in dispatch and freeing up of hosting capacity for new investment, then it may be argued that some portion of the benefits will accrue to both new connecting generators and consumers.

A combination of different approaches can be used for recovering the costs of system strength services. This is consistent with the current frameworks for system strength, being the minimum and do-no-harm frameworks. The minimum system strength framework is paid for by consumers through network charges, while the "do no harm" obligation is paid for by the connecting generator.

75 This includes either from another generator, a competitive provider of a synchronous condenser or some other technology that provides system strength, or through network investment.

76 For example, recovery of the costs of system restart ancillary services (SRAS) are split between subregions of the NEM, and are then split again between generators and consumers.

It follows that a new framework, even if it looks markedly different, may utilise different methods of cost recovery for different aspects of system strength provision. For example, different approaches to cost recovery could be applied for the "essential" level of system strength, while another might be used for levels of system strength that free up dispatch or provide hosting capacity for new generation investment.

4.2 Models for delivering system strength

The Commission's approach to ***planning***, ***procuring***, ***pricing*** and ***paying*** as set out above has been used to map out some general framework models for the provision of system strength. Each of these models can be assessed in terms of the general questions that arise in relation to planning, procurement, pricing and payment, as described above.

Importantly, each of these models are not necessarily mutually exclusive, and elements of each may be combined to deliver hybrid models. The models themselves are intended to represent reference points on a spectrum, which describes the range of different options that can be considered. However, for the purposes of facilitating discussion, we have grouped them into four models. We encourage stakeholder feedback on whether there are particular elements of these models, or combination of different models, that should be pursued.

The general, non-exclusive models are set out in the following sections and include:

- **Model 1: Centrally co-ordinated —** A centrally co-ordinated approach, where networks and AEMO play a central role.
- **Model 2: Market base decentralised —** A decentralised approach, where competitive forces play a central role in coordination and delivery.
- **Model 3: A mandatory service provision approach —** A more centralised model, where all generators are required to bring an "active" contribution to system strength**.**
- **Model 4: An access standard approach —** A more centralised approach where all generators are required to have a "passive" system strength withstand capability.

As discussed above, these models themselves consist of various elements, for the planning, procuring, pricing and paying for system strength under each model. Elements could be mixed across the various models, to deliver hybrid solutions that utilise different elements from each model. The models are not mutually exclusive.

Similarly, the Commission considers that different models might be used to deliver different levels of system strength. For example, a centrally coordinated approach might be used to deliver levels of system strength critical to supporting system security, while a more decentralised approach might be appropriate for delivering market benefit levels of system strength, such as unlocking dispatch.

Finally, these models could play different roles over different time periods. For example, over longer time periods, some form of centrally planned model might be used to support efficiently coordinated large scale investment in network and generation assets. In the shorter term, a decentralised, market based model might be appropriate for unlocking the benefits associated with provision of system strength over operational timeframes.

Table 4.1: Summary of models

MODELS		CENTRALISED CO-ORDINATED	MARKET-BASED DE-CENTRALISED	MANDATORY SERVICE PROVISION	ACCESS STANDARD
How to plan for the service?	Longer-term investment timeframe	TNSPs and AEMO using: • the ISP • existing transmission planning and system security frameworks.	Investment in new assets to provide system strength would not be centrally planned, although processes like the ESOO, ISP, and generation connections agreement processes may be utilised to guide individual participant decision-making.	Individual parties deciding to connect, includes the ISP and connection agreement processes. A central body could determine and co-ordinate the provision required.	Individual parties deciding to connect, includes the ISP and connection agreement processes.
	Shorter-term operational timeframe	Could be done through either the dispatch engine or separate NSP and AEMO communications.	Could be done by the a central operator dispatching the required level of system strength, based on bids and offers from market participants, or could be decentralized and providers of system strength offer their services to other parties in the system in operational timeframes.	Some mechanism is required for the co-ordination and enforcement of each generator's obligation to be operated. Operational complexity may arise due to coordination / mixed incentive problems across the generation fleet.	May reduce the complexity of system operation, depending on the obligation imposed. Another mechanism that provides active provision of system strength is likely to be required alongside this model.

MODELS		CENTRALISED CO-ORDINATED	MARKET-BASED DE-CENTRALISED	MANDATORY SERVICE PROVISION	ACCESS STANDARD
By what mechanism/s is the service procured?	Longer-term investment timeframe	Central buyer — AEMO or TNSPs builds or contracts	Price signals are created for new investment into system strength in the market when supply is low relative to demand. A secondary contract market to support investment may be required.	Participants buy required equipment before generator is commissioned. The size and specifications of this equipment to provide system strength would be determined by a central body, such as AEMO, Reliability Panel, or the TNSP.	Participants buy equipment of required quality to provide system strength typically before a generator is commissioned.
	Shorter-term operational timeframe	Single operator / procurer of service would also have responsibility for any co-ordination with other services.	Least cost combination of participant offers for system strength services is sourced through the process of generation dispatch. Parties could co-ordinate between themselves and other services.	Given the provision is mandated, this seeks to achieve the co-ordination required.	May reduce complexity of operational procurement if generator responses are well defined. However, some other active system strength procurement mechanism may be required in the short term to provide sufficient volumes of system strength.
How is the service priced?		Regulated approach - least cost procurement	Marginal provider – which may be subject to some form of price	Competitive approach – least cost procurement by parties who face the obligation to	Competitive approach – least cost procurement

MODELS	CENTRALISED CO-ORDINATED	MARKET-BASED DE-CENTRALISED	MANDATORY SERVICE PROVISION	ACCESS STANDARD
	opportunities (potentially through a tender process).	regulation if there is a lack of competition. It could also be pay as bid as each sources of services could be quite different in its impact.	provide the service (probably through a tender).	opportunities by parties who face the obligation to meet the access standard.
Who pays?	Either or both of: • generators through a connection fee • consumers through network charges.	Either or both of: • generators though a causer-pays framework • consumers through wholesale market fees.	• Generators bear direct costs. • Consumers bear indirect costs through higher wholesale costs as generators recoup costs.	• Generators bear direct costs. • Consumers bear indirect costs through higher wholesale costs as generators recoup costs.
Will it promote system security in relation to system strength?	More likely.	More likely.	More likely.	Somewhat – but must be complemented with some mechanism for the active provision of system strength.
Is it suitable for provision of the essential system strength level?	More likely.	Unclear – this model may or may not provide the certainty that is required about the levels of system strength in the	More likely – however comes with a potential risk of over procurement, and inefficient operational outcomes, yet may improve stable operation of	Somewhat – this model supports the provision of the essential level but cannot provide it in

MODELS	CENTRALISED CO-ORDINATED	MARKET-BASED DE-CENTRALISED	MANDATORY SERVICE PROVISION	ACCESS STANDARD
		system, depending on how this mechanism is designed.	inverter-based generation.	and of itself.
Is it suitable for provision of system strength above the essential level?	More likely.	More likely.	More likely.	Less likely – although it may help to reduces the needs above the essential level.

Table 4.2: How each model addresses the issues with the current frameworks

MODELS	CENTRALISED CO-ORDINATED	MARKET-BASED DECENTRALISED	MANDATORY SERVICE PROVISION	ACCESS STANDARD
Can it address the issues with the minimum system strength framework?	More likely	Somewhat - depending on its design this model may or may not be suited for providing the minimum service level, given the critical nature of maintaining a basic volume of system strength at all times for to system security.	Less likely – depending on how this model was designed, it may not be as proactive as would be desirable due to the issues seen with the current “do no harm” obligation.	Less likely - this option reduces system strength requirements but does not increase total system strength provision. That is, it does not actively contribute to system strength and would require some complementary mechanism to ensure that minimum levels are met therefore not be proactive
	Somewhat - the definition of system strength likely needs to be revisited under any evolution of the framework, regardless of the model(s) used. The definition of system strength would relate to fault current for protection systems and impedance for voltage stability as well as the ability of inverters to remain stable and connection to the system.			
Can it address the issues with the "do no harm" framework?	More likely	Somewhat, this may be operational complex. Depending on the granularity of the pricing, the market would may not instantaneously incentive synchronous machines to be connected in all useful / required locations to compete.	Less likely – depending on design, this model may not reduce operational complexity or facilitate greater co-ordinated remediation works. However, operational complexity could be increased depending on specification	Somewhat - but this model would need to be in conjunction with another model as it does not actively provide fault current

MODELS	CENTRALISED CO-ORDINATED	MARKET-BASED DECENTRALISED	MANDATORY SERVICE PROVISION	ACCESS STANDARD
Can it address the separation of the frameworks?	More likely, but care must be taken in how to approach the provision of multiple system services to maximise efficiency and minimise opportunity costs.			

4.3 Model 1: Centrally co-ordinated

BOX 10: SUMMARY OF MODEL

This model describes a centrally co-ordinated and planned approach. Generally, such an approach would aim to co-ordinate and plan the grid into the future as to where system strength assets are required in the medium to long term.

- **How to plan for the service?** This model could build on existing planning processes, such as the ISP and transmission planning frameworks, as well as other system security planning frameworks, including network support and control ancillary services (NSCAS), as well as the minimum inertia and system strength frameworks.
- **By what mechanism is the service procured?** Under this model, a central buyer, such as TNSPs or AEMO, would be responsible for procuring necessary volumes of system strength to meet a central plan, through either contracting with existing generation or building regulated network assets to provide system strength services.
- **How is the service priced?** Pricing of these services could be subject to a regulated approach, and could be determined through the least cost of these procurement opportunities.
- **Who pays for the service?** There are a number of ways that these services could be paid for, including by consumers through network charges, and/or by generators through a pre-determined fee at the time of connection.

This section explores how a centrally co-ordinated, AEMO/TNSP led model might operate, in order to provide the system strength required to support the power system's transition.[77]

There are levels of system strength provision that may lend themselves to a more centrally planned and coordinated approach, to deliver more efficient outcomes. This includes the requirements of the constant provision of an essential quantity of system strength for the secure operation of the power system.

Equally however, centrally planned approaches bring with them innate costs and risks, particularly those associated with inaccurate forecasting. These costs of these inaccuracies are ultimately borne by consumers.

This section steps through the various elements of a centrally coordinated model, considering the elements of planning, procurement, pricing and payment. It also considers some specific benefits and costs associated with such a model.

77 The Commission noted an approach similar to this model in the April 2019 consultation paper. This was built upon by TransGrid in its submission to the *Investigation into interventions mechanisms and system strength* consultation paper. For more information see TransGrid, *Submission to the Investigation into interventions mechanisms and system strength consultation paper*, 16 May 2019.

4.3.1 Planning considerations

As previously discussed, the NEM is in the midst of a rapid transition to a generation fleet that will be increasingly non-synchronous, with synchronous generation retiring, becoming less reliable, or reducing operation.[78]

A centrally planned approach could enable greater proactivity to deliver the necessary levels of system strength, which could in turn reduce the risk of rapidly emerging system strength shortfalls. This proactivity in providing system strength could help avoid the kinds of outcomes currently being observed in South Australia, as discussed in Chapter 2.[79]

This section steps through what planning frameworks might look like under a centrally co-ordinated type model, based on potential elaborations of some existing security planning frameworks. It then explores how a centrally co-ordinated planning approach might help to address emerging issues related to the coordination of new connecting generation, which is relevant to the security impact that a system strength shortfall may have on the power system.

Options for planning and coordination through a centrally co-ordinated model

Such a model could build on existing planning frameworks in the NEM. Generally, these frameworks involve both AEMO and TNSPs working in tandem to plan for system needs. This is on the basis that AEMO and TNSPs have the overall visibility of the long term security needs of the power system. These parties may be best placed to determine and co-ordinate the system strength needs of the power system over the long-term.

A general outline of an AEMO/TNSP led planning process for system strength

A centrally co-ordinated model for sourcing system strength could involve a central process co-ordinated by AEMO and TNSPs. A starting point would be the existing planning processes in the NER, since these could be amended or expanded to provide long-term planning and coordination for system strength. This includes the existing NSCAS, RIT-T, network standards and ISP processes:

- **Network support and control ancillary services (NSCAS) framework:** the NSCAS framework allows NSPs and AEMO to plan for and procure non-market ancillary services to meet specific power system needs. NSCAS could theoretically be adapted to address system strength shortfalls, although this is currently not allowed for under the NER.
- **RIT-T:** the well-established economic cost-benefit analysis test is used to assess network developments. It could potentially be used to assess and rank transmission network investments and non-network options for system strength provision. This would ensure the option selected delivers the highest net economic benefit to those who produce, transport and consume electricity.

78 At least 30GW of new non-synchronous generation will need to connect by 2040, to replace the estimated 15GW of synchronous generation that will retire. See: AEMO, *2020 Draft Integrated System Plan*, December 2019.

79 This is not to say that a decentralised coordination approach cannot also play a role; market type processes may complement a centralised planning approach, and are discussed in more detail in section 4.4.

NSPs have suggested the RIT (in its current form) is not sufficiently prescriptive to allow proactive planning for system strength needs, and that investment in asset of procurement of non-network solutions to address system strength needs will only be progressed once AEMO has declared a system strength shortfall.

- **Network standards:** schedule 5.1 of the NER sets out the *Network Performance Requirements to be provided or co-ordinated by network service providers.* These are the equivalent of the generator access standards, but are applied to networks. They inform how TNSPs plan and build their network. Currently, the network standards do not explicitly include a standard for system strength.

  Some TNSPs have advised the Commission that the lack of a system strength network standard makes it difficult for TNSPs to independently account and plan for system strength needs through the existing RIT-T process.
- **Actioning the ISP:** the draft Actioning the ISP rules[80] include a requirement to consider system security benefits when analysing and making decisions.[81] These draft rules create a new annual *System strength report* that describes AEMO's system strength requirements, including all present or forecast fault level shortfall.[82] This model could be used for the co-optimisation of security services, including over long-term planning horizons. It also has streamlined RIT-T processes for projects contingent on the optimal developmental pathway, which may deal with some issues NSPs have with the current RIT-T.

Under a centrally co-ordinated model, these processes could be evolved. AEMO (with TNSPs) could declare the level needed, with this then procured. They could also identify potential additional amounts of hosting. TNSPs could therefore proactively tender for and procure system strength to satisfy the modelled power system's needs.

This planning would need to be done on a rolling basis and to a forecast horizon appropriate for a TNSP to undertake a full consideration of network and non-network options and subsequently identify and implement the least-cost solution. It would also require sufficiently long time horizons to recognise the time taken to build and commission any necessary assets to provide a system strength solution.

Under this model AEMO and TNSPs would be able to:

- look further ahead than current modelling allows by trading off planning lead time against accuracy of forecasts, when determining system needs. The efficiencies of this potential option would be realised through providing the TNSP with adequate time to consider and implement the least cost suite of options for system strength provision.
- optimise the impact of any system strength investment they make, taking into account the current and emerging system strength needs in different areas of the grid.

An example of how existing planning frameworks could be utilised is set out below.

80 The final rules were agreed by the COAG Energy Council at the meeting on 23 March 2020.

81 See: www.coagenergycouncil.gov.au/publications/consultation-draft-isp-rules.

82 ibid., clause 5.20.6 of the draft ISP rules.

Case study: NSCAS framework

The existing NSCAS framework offers an example of a current planning mechanism that could underpin a centrally co-ordinated approach to planning for system strength.

NSCAS is used by AEMO as the procurement mechanism for a number of security services, such as voltage control. The Commission is interested in views on how this process described below does / would work in practice.

BOX 11: WHAT IS NSCAS?

NSCAS is a network support services framework in the NER designed to:

- promote power system security and the reliability of the transmission network
- maintain or increase the power transfer capability of the transmission network in order to maximise net economic benefits.

NSCAS requirements are identified by AEMO as part of its National transmission network development plan (NTNDP) processes after taking into account all activities that have been identified by the TNSP. As such, NSCAS requirements represent a gap between the level of services that have been identified by AEMO as necessary and those that have been identified by the TNSP. This is referred to as the NSCAS gap and can be for system security, reliability or market benefit.

Where a gap is declared, the relevant TNSP has the option of deciding to meet the gap or not. If the TNSP elects not to, and the NSCAS gap is for security or reliability, AEMO can meet the gap as a procurer of last resort. However, when in this role AEMO can only acquire services to address system security or reliability NSCAS gaps, not market benefits.

A benefit of the NSCAS framework is that it includes a number of features that reduce the risk of inefficiently high prices in response to tender processes, where a system service is urgently required to manage a declared gap.[83]

For example, if the TNSP elects not to address a gap, AEMO can choose to do so as a procurer of last resort. When doing so AEMO can decide not to contract with market participants for the provision of the service (for example, if the price discovered through the tender is excessive) and can instead rely on its ability to issue directions where this is required to maintain security or reliability.[84]

System strength shortfalls were excluded from being addressed by the NSCAS framework in the final *Managing power system fault levels* rule change.[85] The Commission considered that

83 ElectraNet's submission to the *Managing power system fault levels (ERC211)* and *Managing the rate of change of power system frequency (ERC214)* draft determination, 8 August 2017, p. 2-11.

84 This occurred in January 2019 when AEMO issued a direction to Snowy Hydro for the provision of voltage support. Snowy had previously been contracted to provide such services to AEMO in the period February 2013 to June 2018 but the NSCAS contract had not been renewed. See: IES, *AEMO direction to a NSW participant on 24 January 2019 to operate a unit as a synchronous condenser, Final report*, 17 July 2019, p. 5.

85 Inertia is similarly excluded from being provided under the NSCAS framework by the final *Managing the rate of change of power system frequency* rule.

a separate framework for the provision of system strength was preferable to the management of the service under the existing NSCAS framework at the time for the following reasons:[86]

- *Effectiveness of NSCAS framework* – The understanding was that in practice the framework had not worked as effectively as possible.
- *Regular assessment of potential requirements* – The more ad-hoc fashion of NSCAS gap identification was considered less desirable than the annual assessment under the new framework.
- *Transparent framework to assess requirements* – There is limited transparency as to the assumptions that AEMO uses when declaring a NSCAS need, whilst a separate framework requires an explicit methodology to be developed and maintained.
- *Anticipates future requirements* – The NSCAS framework tends to address issues as they arise, whereas a separate framework envisaged shortfall forecasting into the future.
- *Clearly defined obligation on TNSPs with regulatory oversight* – The new minimum level system strength framework that was introduced in 2017 places a clearer and better-defined obligation on the relevant TNSP to meet system strength requirements. In contrast, under the NSCAS framework, TNSPs may elect not to address the requirements.

Co-ordination with other services

A further strength of a centrally planned and coordinated model is that it could allow for better co-optimisation or co-ordination of system strength with other services. For example:

- If all system services (e.g. including inertia, voltage control) are being procured by the same party, then that party can make more decisions that provide services more efficiently e.g. decisions could be made to fit flywheels to synchronous condensers, which would provide inertial support service as well as system strength service.
- System strength can be provided in multiple ways, including through localised provision — such as through installing a local synchronous condenser — or reducing the impedance of the network connection to other parts of the power system, such as by building additional network assets. Such considerations may be able to be taken into account more easily if system strength is provided in a centrally planned manner.

Co-ordination of generator control systems

The Commission also understands an emerging issue relates to the speed that new non-synchronous generation systems are connecting to the NEM, particularly in weaker parts of the power system. The currently unco-ordinated nature of these new connections may be creating new risks associated with unpredictable interactions between generator control systems, which are increasingly likely to result in system instabilities. These interactions may be problematic, or harder to model and predict, in low system strength conditions.

86 AEMC, *Managing power system fault levels*, Final determination, September 2017, p. 30.

The timely provision of additional system strength may therefore go some way to reducing the complexity of these inverter control system interactions, and could therefore reduce the risk of major system instabilities.

This issue is related to the concept that the provision of system strength above essential levels may help provide additional "hosting capacity" in certain areas of the system. In this context, hosting capacity refers to the idea that parts of the power system with higher levels of system strength may be better able to support more connections. This is because in a stronger part of the system, the process of control setting coordination will be more straightforward and lower the risk of unintended interactions and related instabilities. This may both speed the process of new connections, and improve the stability of operation of those generators once they are connected.

However, the provision of additional system strength is likely to only address part of this issue, as the underlying cause is the sheer number of new connections, with the associated need to coordinate control settings in order to avoid instabilities in low strength parts of the system. The Commission understands that these issues will not be addressed through the provision of additional system strength.

While such a co-ordinated approach to control settings could support a more secure system, and could also facilitate more efficient investment, careful consideration is required. Any intervention in the currently decentralised approach to generator connection brings with it the risk of unintended consequences. Connecting generators may face new incentives under a co-ordinated approach. Furthermore, while a co-ordinated approach may bring some security and investment benefits, it may also reduce the competitive discipline currently faced by connecting generators.

More generally, questions relating to the generation connection process fall outside the scope of this investigation. This reflects the fact that while system strength may be relevant to the effective coordination of generator control settings, the broader question is how to manage the increasing number of new generator connections to the NEM. This question is being considered through several work programs being progressed by the AEMC and the ESB, including the *Co-ordination of generation and transmission investment* review, and the *Actioning the ISP* work program.

Allowance for a longer timeframe for NSPs to plan and build is most likely required for a centrally co-ordinated model to be effective. However, this will involve accepting the stranded asset risks associated with such a model. In other words, the balancing of timeliness and accuracy, as discussed in Chapter 3, will be critical to the success of this model.

Additionally, it would be important to structure this model with clear responsibilities. This is to uphold the accountability required for compliance as well as to reduce any unnecessary duplication in planning processes, like forecast modelling.

Finally, there are also a number of complexities and challenges that would need to be overcome for this model to be implemented. The most significant complexity is that the demand for system strength is not static. Rather, it changes with respect to the demand for and supply of energy, and associated changes in the dispatch of the synchronous generation fleet. The unpredictability of these dispatch patterns makes highly accurate forecasting and planning for necessary volumes of system strength challenging in the short term, and very nearly impossible over the medium to longer term. It may be difficult to account for these complexities in a long term, centrally coordinated planning approach.

4.3.2 Operational considerations

The power system's requirement for system strength changes over operational timeframes, dependent on which generators are dispatched at the time. As such, a key consideration of a model for providing system strength is how it will interact with the dispatch of other system services, especially energy. This involves coordination and/or control in an operational timeframe.

Under a centrally co-ordinated model, a central body, such as a TNSP or AEMO, who has good visibility over the system's needs, would be in a position to have control over the provision of system strength. This would mean that there would be:

- **A transparent, single controller of assets:** Central provision of the service would address the concerns of increased operational complexity arising from the installation of multiple, discrete assets, such as is occurring under the current "do no harm" framework.
- **Coordination of co-optimisation of other services:** A central body could also co-ordinate and optimise the provision of other security services — such as inertia — as well as understanding the interaction of system strength needs with thermal transmission limits.

Consideration of all technology options and potential providers of system strength would help to minimise the long run cost of providing system strength. This is by virtue of the competitive pressures that would exist between all participating parties. For example, a central coordinating body:

- Would be able to recognise that there is no value in providing sufficient system strength to facilitate the connection of 2 GW of new generation in a part of the network, if the relevant thermal limits would only allow connection of an additional 1 GW of generation.
- Can co-optimise and efficiently take into account multiple services when remediating a gap, where a solution can provide multiple security services. For example, the TNSP could identify whether the provision of reactive support and inertial control could be efficiently provided at a small incremental additional cost, when building a network solution, or sourcing a non-network solution, for the provision of system strength.
- Would need to have adequate time to consider all network and non-network options in identifying the least-cost solution for the long-term provision of system strength.

4.3.3 Investment considerations

A central co-ordinating body would have the ability to take a longer term view of the needs of the power system, which could support planning for the optimal location of system strength assets. This could be done in conjunction or as part of long term planning processes such as the ISP, to better facilitate the transition to a power system with high levels of new non-synchronous generation.

This approach is consistent with the concept of the various levels of benefit that can be unlocked through provision of additional volumes of system strength, above the essential level required to maintain system security. In particular, a central planning body could take responsibility for pre-emptively providing additional volumes of system strength, to enable greater "hosting capacity" of the network, to facilitate greater volumes of new generation seeking to connect to the system.

Potential benefits of this model could include:

- **Potential reduction in connection time for new entrants -** A central planning body could work to reduce the kinds of generation investment bottlenecks that are currently observed in parts of the NEM, where provision of system strength has not kept pace with levels of new generation investment, by pre-emptively providing necessary system strength before the system becomes critical. This could be achieved by reducing the complexity of modelling requirements, as well as by removing the need for connecting generators to undertake their own system strength remediation works.

  A centrally co-ordinated model could therefore streamline and reduce the time taken for the connection of new generation (although we note that under current frameworks, modelling would still be required to assess a new connection's compliance with the generator performance standards (GPS)). However, the process of modelling and connection could be simplified and streamlined if some volume of system strength was already planned for and provided, prior to a generator's connection. Such an approach could also reduce capital costs borne by new entrants. TNSPs would be able to take advantage of economies of scale through the co-ordinated provision of system strength services.
- **Increased predictability in the connection environment** - generators could be left with a process that could be considered to be technically and procedurally simpler, as a large portion of the complex system strength modelling and procurement process could be undertaken ex-ante by TNSPs. This is especially true for investors who are less familiar with the technical details of the power system, potentially reducing investment risk in new capacity. This could help facilitate further investment in new capacity, put downward pressure on wholesale energy prices and facilitate the replacement of the ageing synchronous generation fleet.

A potential elaboration on the concepts discussed above could involve the central planning body, either the TNSP or AEMO, taking on the bulk of responsibility for the modelling and assessment of a generator's impact on the power system. In doing so, this central body would be responsible for determining the specific settings of the generator's control equipment. This could include a requirement for the central body to be responsible for any subsequent (post commissioning) requirements to model, and require retuning, of generator equipment.

Under higher levels of system strength, this would be a less onerous task for a central body, as the power system modelling needed to inform this process would likely be markedly simpler than under existing low system strength conditions. However, this may not solve the impacts on other generators.

Such an approach could be accompanied by a clearly defined obligation for all generators to bring a given level of system strength "capability". That is, all generators would be required to demonstrate, as part of their connection process, that they could operate stably down to given levels of short circuit ratio (SCR). However, the specific settings of the control equipment, including how the particular generator is tuned to respond to specific SCR levels, would be the responsibility of the central body.

The basis of this approach is that, provided the generator clearly demonstrated it had the physical capability to maintain stable operation under a range of reasonably onerous SCR conditions, responsibility for modelling and determining the specific tuning and response of the generator control settings would sit solely with the TNSP or AEMO.

As well as affecting the current "do no harm" framework, this particular approach would likely also require adjusting some generator access standards elements, and the process whereby negotiated access standards are defined on a connection by connection basis. For example, if a single mandated level of capability for system strength "withstand" was required, it may not be appropriate to have a range of potential capabilities to be negotiated between minimum and automatic.[87]

A potential benefit of an approach like this would be to reduce the uncertainty currently associated with the assessment of the impact of each connecting generator. As described in Chapter 2, this uncertainty currently translates into significant modelling complexity, which can add materially to the time to connect a new generator. Defined capability of each connecting generator may also go some way to providing increased certainty to AEMO and NSPs as to what all generating systems connected to the power system are capable of delivering.

4.3.4 Cost recovery method

The costs of the system strength provision procured by a centralised co-ordinating body could be recovered, either in part or full, in several ways:

1. **Generators pay through a connection fee:** This approach keeps the high-level principle of the "do no harm" obligation — that generators should pay for the portion of system strength required to facilitate their connection and operation. However, the way that costs are allocated to a generator could be significantly simplified from current arrangements, to provide a more predictable charge. This would allow better informed project planning and financing deliberations.

   A simplified connection fee could be determined as a single upfront fee that is pre-determined by the TNSPs for connection of that capacity in that area.

87 The current approach to the setting of generator technical performance standards is based on a process of negotiation, whereby the generator, AEMO and NSP determine a specific set of performance standards that must sit somewhere between the NER defined automatic and minimum access standards.

2. **Consumers pay through transmission use of system (TUoS) charges:** This approach is consistent with current arrangements for when a TNSP addresses a minimum system strength shortfall. A weakness of this approach is that it does not provide any locational signal to new connecting generators. However, its strength is that it would somewhat simplify the connection process by removing a now unknown cost for generators. This assists in addressing investment uncertainty due to low system strength issues.

The ideal cost recovery mechanism would provide locational signals to new connections while protecting consumers from inefficient expenditure.

Ideally, new entrants should also retain the option to undertake remediation on their side of the meter, if they can do so more efficiently while delivering equivalent system security outcomes. That is, connecting generators could be given the option of undertaking their own remediation work instead of paying the standardised connection fee, if they considered they could deliver the same outcomes at a lower cost.

Such a model could retain a signal for new entrants to invest in measures to reduce or wholly offset their system strength impact as new technology becomes available. This would enable new entrants to contest the costs determined by TNSPs and facilitate innovation. It would also reinforce the discipline on TNSPs to procure the least cost solution discussed above. However, a major concern is the potential for increases in operational complexity associated with allowing multiple connecting parties to build and construct assets to manage system strength.

4.3.5 Benefits of this model

There are benefits of procuring system strength services under an option that is centrally co-ordinated, including that a centrally co-ordinated model allows:

- System strength remediation procurement options to include both network asset options (like synchronous condensers) and non-network options (like generator contracting). In selecting options to provide system strength, a central body could have scope to consider potential developments in technologies, which may help reduce costs for generators and consumers.

  This broader scope of potential solutions to a system strength shortfall is clear benefit of a centrally co-ordinated model. For example, a central coordinator could elect to contract with synchronous generators to provide this service, or could require a TNSP to develop a regulated network, or non-network, solution. Such a body would then be able to trade off between these two solutions, to find the lowest cost option for consumers.
- Access to a wider range of potential sources of system strength. This would impose greater competitive discipline on all providers of the service, and help to reduce costs for consumers. Having a central coordinating body procuring these services would allow for better consideration of the trade-offs that exist between provision of system strength from localised sources (such from a synchronous condenser), as well as from reducing impedance on the shared network through new transmission line build.

Both TNSPs and AEMO are well positioned to understand these interactions, and could plan to co-optimise between the two "sources" of system strength over the long term.

- Be well placed to take advantage of any opportunities for co-optimisation across the provision of multiple system services. A central co-ordinating body may have access to needed information, and the capacity for forward planning, to identify and take advantage of the scale economies that may exist through incremental investment to meet system needs.
- Be well-placed to understand the scale of investment and respond proactively within a short period. This is important given that the speed of the transition to an increasingly non-synchronous generation fleet inherently injects some level of unpredictability into power system forecasting and planning - potentially causing system strength shortfalls to arise unexpectedly.
- Facilitating the smooth and timely provision of this critical system service. A single planning body may be able to better identify any shortfalls in system strength before they arise, and arrange for the appropriate solutions to be put in place well in advance. This advance planning may help to avoid issues in the short run, such as where a sudden shortfall in system strength requires material constraints to be applied to non-synchronous generators, or results in significant out of market interventions by AEMO. Over the long run, this may help to reduce the uncertainty and costs currently associated with the connection process, which will facilitate more efficient investment in new generation.

It is also important to note that a central co-ordinating body will have access to multiple technologies, now and into the future, to provide system strength. Specifically, synchronous condensers are not the only option available to a central co-ordinator to provide system strength, with a number of other network and non-network remediation options available. A centrally co-ordinated model could provide the flexibility to allow for system strength remediation to be addressed through various technologies and solutions, which could allow for co-optimisation with other beneficial outcomes. This includes thermal constraint relief and the provision of inertia, to ensure the most effective solution.

An example of the benefit of flexibility is when the system strength in an area of the grid can benefit from standard transmission upgrades. That is, the upgrade can allow for the system strength provided by distant synchronous generators to be better transferred to weak areas. Transmission upgrades can entail a suite of benefits and may in fact be found by TNSPs to have greater market benefits, beyond system strength benefits, even where the costs of procuring system strength from existing generators are taken into account.

4.3.6 Downsides of this model

This model relies solely on the effectiveness and capability of the central co-ordinating body to discover the lowest cost solution. The complexity associated with the changing demand for a system strength service may make it very difficult for the efficient provision of the 'right amount' of system strength under this model.

It may be possible to address these issues where there is sufficient time to plan and procure the service, as envisioned in the Commission's approach to any changes to the framework. However, it remains the case that any errors in forecasts and modelling may translate to inefficiencies and increased costs for consumers. This is either through paying for assets that are not used, or by not having enough system strength in the system and so faxing higher wholesale costs as a result.

Additionally, careful consideration would be required to in order to use this model in both operational and investment timeframes. This would be such that efficient and effective level of system strength is provided for each dispatch interval.

4.4 Model 2: Market-based decentralised

BOX 12: SUMMARY OF MODEL

This model describes a decentralised approach that utilises dynamic procurement of system strength over a shorter timeframe, but where the price signals sent in this market could support longer term investment decisions in the provision of system strength. This model requires that system strength could be co-optimised into dispatch in some manner.

- **How to plan for the service?** "Planning", or coordination, would be decentralised, with individual parties deciding to participate in the system strength market.
- **By what mechanism is the service procured?** Procurement of the service would be done at dispatch with system strength assets being dispatched according to their bids to provide system strength to the market, with the least cost combination of assets dispatched.
- **How is the service priced?** The price would be set by the marginal provider of service - or may be subject to some form of price regulation, if a market price is a concern in this market due to a lack of competition.
- **Who pays for the service?** The service would then be paid for by consumers through wholesale market costs, and/or by generators through a causer-pays style approach who have a negative effect on system strength.

This section explores how a market-based option may operate. The dynamic nature of a market model allows for optimised dispatch to drive productive efficiency gains, system security service 'value stacking' for investments and allows the participation of both existing and new players.

The AEMC has received the *Synchronous services markets* rule change request from Hydro Tasmania. This rule change request proposes a market-based model for the provision of "synchronous services", which shares some similarities with the general model discussed in this section. However, the Hydro Tasmania proposal is a cost optimisation over 5 minute dispatch timeframe, rather than a market that has the direct pricing of the service.

This rule change request will be formally initiated soon. It should also be noted that the Hydro Tasmania rule change request discusses *synchronous services,* and not specifically the provision of system strength. For information the rule change request is available on the AEMC website.[88]

4.4.1 Planning considerations

A market-based model would still be co-ordinated, but would do so in a somewhat 'unplanned' manner. That is, market participants would make their own decisions, not a central planner. These decisions include if to enter the market, what technology they would do so with, and where it would connect to the grid. However, as long as sufficient information is provided and price signals are adequate, a decentralised market approach can still deliver a degree of coordination.

Transparent information, particularly price signals, is a core requisite for such coordination to work efficiently and effectively. Potential investors require an understanding of what is currently occurring in the market and how that could influence their entrance and operation to be able to do the due diligence necessary for sustainable investment.

Additionally, large scale central planning processes like the ISP can complement market function, by providing guidance to potential investors to effectively and efficiently participate in the market. As it does for energy now, the ISP provides information as to the need and location of major infrastructure required by the power system. System strength providers could use this information about the future to help determine where and when they should enter the market. The result would expect to be potential market participants doing so in a more co-ordinated way.

An option such as this has its benefits regarding planning and coordination including it:

- allows for the lowest cost solution to rise to the fore - competitive pressure is created between potential new entrants as they look to use the least cost solution, as this would lead to them having the most competitive bid/price. This should provide the discipline for the least cost solutions being implemented.
- investment cost risks are not borne by customers but by investors - any unnecessary investment would then not be charged directly to consumers.

A model like this also has some risks regarding planning and coordination including that:

- this essential security service could end up not being available or delivered at dispatch if the market signalling is not effective. This is because this model is inherently planned on a relatively short-term basis, and therefore may not be able to be as proactive as required to facilitate the transition occurring.
- the locational-specific needs of the system must be accounted for in this model, which may be more difficult in this option than in others.
- market power of individual providers could create major issues. This is explored further in Section 4.4.5.

88 See: https://www.aemc.gov.au/rule-changes/synchronous-services-markets.

4.4.2 Operational considerations

A core challenge in implementing a decentralised, market based approach relates to the difficulty in formulating the constraints and gaining the resource visibility in NEM dispatch engine (NEMDE) for an optimised dispatch. This is due to both the technical nature of system strength but also current limitations in the capabilities of NEMDE.

Complexity of constraints

The NEM dispatch engine (NEMDE) is a computer program that determines the least cost combination of generation to meet demand. It does this every five minutes, and adjusts its solution to reflect the physical limits of the system.

This is achieved by imposing "constraints" on NEMDE, which are equations that represent the various physical limits of the power system, such as thermal, voltage and transient/oscillatory stability limits. These constraints must not be exceeded, in order to maintain the power system in a safe and secure operating state.

Iterative nature of deriving constraints

System strength constraints reflect numerous very complex interactions in the power system. As such, they are determined by using complex modelling and then incorporated into NEMDE.

Therefore any major changes to the system strength requirements of the system may trigger complex remodelling, followed by reformatting of all relevant NEMDE constraints. These changes include the exit or reduced operation of synchronous generators, the construction of new transmission assets (such as synchronous condensers, interconnectors or transmission lines) or changes in demand. This is a highly iterative and onerous process that may not be viable in a rapidly transitioning power system.

Additionally, NEMDE constraints may need to be reformatted, following any network augmentation, as this may change the volumes of system strength needed and supplied into a region. TNSPs and AEMO would also face challenges in determining how much system strength the regional market or network must procure, considering that one solution will feedback iteratively to the other.

The Commission understands that calculating near-real time, dynamic constraint equations for system strength limitations is a computationally intensive process, and one that is not feasible in the medium-term future. While developments in computational power may make this feasible in the future, current limitations mean that system strength constraints must be determined on a static basis, utilising pre-determined sets of synchronous generator combinations to provide system strength.

It may be possible to simplify system strength constraints in a manner that could support a market model, despite the process of developing and applying them being complex.[89]

89 In the future, computational power may advance such that complex system strength constraints can be created and solved in real time. However, this is not considered to be possible for some time.

As an example, AEMO is currently adopting an approach in South Australia to manage system strength, where constraints are applied across the system to determine the total system strength needed. By comparing different "runs" of NEMDE, with and without these constraints applied, it may be possible to determine an estimate of the cost of providing needed system strength. This could in turn be used to inform a market price.

Visibility of resources in dispatch

The creation of a new registration category, such as a *synchronous service provider,* would likely need to be added into NEMDE for it to be able to make a market-based model operational. Also, AEMO would have to consider any extra measures it may need to take to preserve system security when sufficient synchronous generation does not come online as a result of this model, like using directions. This is because NEMDE is not currently designed to ensure the unit commitment of system strength providing generators.

AEMO would also need to know what these synchronous service providers are doing in the market. This visibility of resources could simply be included in pre-dispatch, or could have more obligations put onto participants due to the complexity of the service.

Potential 'aheadness' requirement

On 6 December 2019, the Council of Australian Governments (COAG) Energy Council tasked the Energy Security Board (ESB) with "investigating interim measures to preserve reliability and system security in the NEM as it transitions to the 2025 market design".

As part of this, COAG Energy Council requested that the ESB "provide advice on arrangements to give visibility of available resources and options to ensure their sufficiency, including ahead markets and unit commitment runs, to ensure that the right resources are available at the right time to ensure co-optimisation of necessary resources and services". Detailed analysis on this will be provided to COAG Energy Council by the end of 2020.

The ESB, in coordination with the AEMC and AEMO, is assessing options to improve the management of security and reliability issues. The work by the ESB will be run in parallel with the Commission's work on this review.

4.4.3 Investment considerations

A key consideration is the need to facilitate investment in system strength services that will support the transition to a high penetration of non-synchronous generation over the mid to long term. Providing such long term signals requires underpinning contracts exchnged through secondary markets, such as those that currently exist in the energy market. Creating such markets for system strength may be complex, given its characteristics.

However, the presence of some form of market model for system strength would allow merchant assets that can provide various security services to 'value stack' the profit from these different system security services. This can increase the viability of investment cases, and in turn may increase the level of competition in the system strength service market.

As identified by several stakeholders, introducing a market model would price the system strength being provided by existing generators, which is currently a service not being directly valued. Using existing assets may be an efficient method of procuring system strength, at least in the short to medium term. It is unclear how locational needs and signals would be taken into account in this option - would there be a need for more granular market pricing in order to signal the locational aspects of system strength?

However, there are a number of complexities associated with a market based approach, including potential issues of market power (explored in section 4.4.6), and unintended interactions and distortions in energy markets that could create feedback loops (explored in section 4.4.4).

The majority of existing assets that can provide system strength are expected to retire by 2040. As such, an important consideration is the need for new investment in assets that can provide system strength. A question to be answered is whether a market model for the provision of system strength is capable of effectively and efficiently signalling and incentivising this new investment.

An efficient market aims to send signals for new investment in the market when supply is low relative to demand for the service. The price in the system strength market should reflect what the generator is willing to be paid for the service. in turn, this price should reflect investment at the level required for the:

- asset's LRMC, that is the cost of capital investment required for a generator to enter.
- contribution for the asset to be viable if it is able to provide multiple services, like energy or inertia. In this way, an investor can stack the profits of providing those services together, in order to achieve financial viability. This price would therefore include the economic assessment of all other markets that could potentially be accessed at the same time, such as the energy market.

If system strength was to be sourced solely on a market basis, then such a market must be able to send price signals sufficient to drive efficient short term operational outcomes, as well as efficient long term investment outcomes. This would require a strong price signal to be created by any such market to incentive a new entrant to be comfortable that they would be able to make sufficient return on their investment.

A question that arises is what kind of market model is needed to provide investors with this comfort. That is, whether a spot market by itself provides sufficient revenue certainty, or whether some kind of underpinning secondary contract is necessary.

Careful consideration also needs to be taken when designing such a market's settlement processes, such as those that may be needed to manage market power issues to reduce the risk that opportunities for profit are restricted to a level that would make new entry uneconomical.

In order to have appropriate competition for the system strength service, it would be necessary to consider how network and non-generator merchant assets such as synchronous condensers could be able to participate in a spot market model. This may require changes to the NEM dispatch engine.

4.4.4 Pricing and cost recovery method

The methods for how to create a price for and recover the cost of a market-based model are a key design consideration and are explored below.

Pricing — How much to pay?

The prices for settlement could be derived from the shadow prices resulting from the set of constraints from an approved combination of generation that solves at least cost. This follows from the fact that a shortage of system strength (or any ancillary service for that matter) results in a change to the merit-order via additional constraints on dispatch. Hence, the value of system strength is observed in the corresponding constraints that are alleviated.

In the context of system strength being provided by generators, a shadow price-based approach would create a separation between the energy price received by those generators that provide system strength (for example synchronous generators, but could also include non-synchronous generators that couple with a synchronous condenser) and those that do not provide system strength (like non-synchronous generators).

As discussed previously, system strength is a lumpy service. That is, that it cannot be provided in a linearly like active fashion like energy and frequency control. The cost of system strength provision is therefore akin to the start-up costs incurred by generators (synchronous and asynchronous alike). In energy-only markets, energy prices (i.e. $/MWh) are used to recompense a generator's start-up costs; this could also apply for system strength provision and could be done using a shadow price-based approach.

However, the lumpy nature of the provision means economies of scale is an important consideration – and could by extension suggest a single system strength provider as the efficient outcome compared to multiple providers – which is an important design consideration for a market-based approach.

Cost recovery — Who pays?

The choice of cost recovery depends on the following two considerations:

1. The provider of system strength, including the extent to which scale economies are relevant in determining the appropriate choice of system strength provider.
2. Whether consumers or generators should pay for system strength provision, depending on which of these broad parties are considered to benefit from extra system strength.

   For example, extra system strength could be seen as akin to a frequency raise service, in which case the costs of system strength provision could be effectively allocated on a "causer pays" basis - that is, to non-synchronous generators. This is in effect what the price separation approach noted above achieves.

In terms of the first consideration, market participants could pay for system strength provision even when the provider is a network business i.e. it doesn't necessarily mean that system strength provision is a regulated, consumer-pays, service. This is how NSCAS provision currently works, and would be consistent with the idea that the lack of system strength provision is a generator, rather than a load, issue.

Alternatively, if the preferred approach is not to create a price separation, then a 'causer pays'-type approach could be adopted. Under this non-synchronous generators would pay for any additional system strength provision that alleviates constraints on their output, akin in principle to how regulation FCAS costs are recovered.

In either case, the dynamic price signals of the market would encourage non-synchronous plant to decrease their system strength impact through plant modifications or, when the price of system strength provision is high enough, allow them to lower their output or de-commit. Noting that this approach would only be applicable for levels of system strength above the minimum quantity needed to maintain system security.

Another potential method is that where system strength is provided to meet the security needs of the system. The costs of doing so could be paid by the relevant TNSPs and passed on to consumers through transmission use of system (TUoS) fees, or to generators through a specific "system strength" charge. This would apply in the event, and to the extent, that system strength provision was considered to benefit consumers as opposed to generators.

4.4.5 Benefits of this model

The dynamic nature of a decentralised, market model could allow for optimised dispatch to drive productive efficiency gains, system security service 'value stacking' to support efficient investment, and allows existing assets and new investment to participate. These positive aspects of a market-based model are explored below.

Irrespective of whether or not scale economies exist, there are potential benefits associated with a decentralised, market-based model. In the presence of scale economies, a competitive tender process, similar to AEMO's NSCAS or SRAS procurement processes, can be applied. In the absence of scale economies, a process similar to FCAS provision could be applied, potentially utilising a hours-ahead type mechanism. In particular such a model could be used to fine tune the provision of system strength in operational timeframes.

Another benefit of a decentralised, market based model is that risk allocation and the accountability for investment and operational decisions rests with those parties best placed to manage them. Solutions that allocate risks to those market participants that are best able to manage them, are more likely to drive efficient outcomes in the long run.

Furthermore, these arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a secure supply of electricity. This is irrespective of the preferred choice between regulatory arrangements and market-based arrangements (or a combination of both).

4.4.6 Downsides of this model

The uncertainty of system strength procurement and the potential difficulties in establishing a market-based model lead the Commission to find that this model is unlikely to be appropriate to provide system strength up to the essential level needed to keep the power system in a safe and secure operating state in the longer term planning timeframe. However, such a model may provide an appropriate mechanism for providing system strength for above the essential level in the operational short-term timeframe.

It is unclear whether based on today's arrangements a market-based model could incorporate the competitive pressure of potentially lower-cost technology solutions to system strength provision. This could include network solutions that provide a number of system security services and market benefits. Network solutions could in turn include the installation of higher capacity transmission lines. In the absence of incorporating synchronous condenser or grid forming inverter or some other technology that provides system strength providers into the market, then such a solution may not be fit for purpose in the longer term.

Over the longer-term, while synchronous thermal generating units may remain online, these units are likely to reflect a decreasing proportion of the fleet as the system transitions to be increasingly non-synchronous and renewable. As such, over the longer term it is decreasingly likely that system strength can be provided by the existing generation fleet. Alternative sources of system strength will therefore be needed. Given the above, a market whose only participants are synchronous generators would likely only be feasible as a short to medium term arrangement.

Further to this, the capability of a market based model to provide necessary system strength services may not be capable of providing essential levels of this service in all regions. In certain regions of the NEM many non-synchronous generators are locating in regions far from synchronous generation centres. This is due to a combination of network topography, renewable resource availability and the location of existing synchronous generation. The long distance (and high network impedance) between the new non-synchronous generators and older synchronous generators, means the latter cannot physically supply system strength to the new assets. As such, a market model to source system strength from existing synchronous generation assets would not be capable of meeting system strength requirements in the region.

Potential market power issues

In addition, there may be concerns about market power in a market-based model, given the risk of limited competition for the provision of system strength services. This is due to both the locational nature of the service, and the (currently) limited number of potential providers of the service. Some system strength providers may have significant market power due the market having limited competition. This could result in customers (non-synchronous generators and/or consumers) incurring very large and inefficient costs for both the service of system strength and energy.

Therefore, some form of regulation may be necessary in order to protect consumers from high costs. Two potential ways of managing market power issues, which could be used by themselves or in combination, are:

- **Using constraints on VRE:** the potential for market power issues would likely be of less concern when incentivising the provision of system strength above the essential levels needed for a secure power system. In this case, the transient pricing power of any individual generator would be limited by the alternative of constraining off non-synchronous generators[90] or simply not procuring additional system strength. However, this approach cannot be used for volumes of system strength below this level, that are critical for the power system to operate in a stable and safe manner.
- **Some form of price regulation:** there are many forms of price regulation that could be used to manage market power, and these could be used in combination or by themselves. These include the use of:
  - *A price cap and cumulative price threshold*[91] - a price cap (maximum price that can be recovered is set), which is combined with a cumulative price threshold, which triggers an administered price cap for a particular service for a given time after a sustained period of high prices.
  - *The deemed service provider approach* - would introduce an ex ante offer cap in the event that a system strength provider is deemed to be pivotal. This approach works by a regulated offer price cap that is automatically applied through dispatch if a generator fails a pivotal supplier test. The test is a market power test, and the regulated price applied would be determined with regard to the prevailing market conditions.
  - *A set regulated price for the provision of the service* - involves a standardised price for each area being paid to all appropriately located system strength provider. The price would be set such that the required quantity of system strength providers that bid, or are contracted, would receive payment. A benefit of a regulated pricing mechanism includes that it could provide a clearer and more predictable pricing signal to guide the investment decisions of new entrants. However, it may be difficult to set the regulated price at an efficient level given the very different cost profiles of synchronous generators and synchronous condensers.

4.5 Model 3: Mandatory service provision model — generator provision obligation

> BOX 13: SUMMARY OF MODEL
>
> This option would impose direct "active" system strength provision obligations on generators — this model describes a centralised approach, utilising a generator obligation for the active provision a given level of system strength.

90 As increasing volumes of non-synchronous generation require increasing levels of fault current to support stable operation, an alternative to supplying more fault current is simply to reduce the volume of non-synchronous generation online.

91 The energy and FCAS spot markets manage excessive costs faced by consumers by using a price cap and a cumulative price threshold approach. While in these markets this approach is not used to directly manage market power issues, a similar approach could be used in a system strength market-based model's design to help mitigate market power issues.

This would be similar to the current "do no harm" framework, with some obligation placed on each generator to provide a standardised level of system strength.

- **How to plan for the service?** Planning of this model would be similar to that already undertaken for generators, including the ISP and connection agreement processes.
- **By what mechanism is the service procured?** The service would be provided by each generator, as part of its generator performance standards negotiated with its connection agreement. As such, "procurement" of the service would operate through this obligation, and would be the sole responsibility of each generator to provide the required level of system strength. It is assumed each generator would choose the lowest cost option for their situation, to meet this obligation.
- **How is the service priced? Who pays for the service?** Generators would bear the direct costs of this model, with consumers indirectly bearing costs through higher wholesale prices, as generators seek to recoup their increased capital costs.

This model would require all non-synchronous generators to provide the fault level similar to that of synchronous generators. The Commission considered the use of such a generator obligation as a model to acquire system services in the 2017 *System Security Market Frameworks Review*.[92] While the focus in that review was on the mandated provision of inertia and fast frequency response system services, the same principles could be applied to system strength services.

A generator obligation would involve the imposition of a minimum technical access standard on each generator in the NEM to provide a specified level of system strength services, so that power system security is maintained. This could involve either an:

1. obligation on generators to physically acquire or build the necessary equipment to meet the specified technical performance standard; or
2. an option for generators to enter into an agreement with another generator or system services provider for the required level of system strength services.

4.5.1 Planning considerations

Setting the level of the obligation, or essential level of system strength, is a key design consideration for this model, as set out in chapter 3.

Under this model, the obligation on generators could be determined upfront, with limited scope to vary over time. As such, there is a risk that a generator obligation may be under or over-specified, increasing the costs of maintaining system security over the long term.

The establishment of a generator obligation would require the exact nature of the obligation to be specified, and the level of the obligation determined, at the time of connection of the generator.

92 AEMC, *System Security Market Frameworks Review, Interim report, 15 December 2016, section 5.4.6.*

There are two possible approaches, both with significant issues, to specifying the minimum level of fault current that generators could be required to satisfy under this model:

1. **Generation online:** the essential level of fault current to be provided could be specified in terms of a minimum fault level in MVA per MW of generation capacity online. That is, generators are not required to provide the service to the system if they are off-line or otherwise not dispatched.
    - For example, a 3 MVA per MW minimum standard would mean that when a generator has 100 MW of generation online, it would be required to provide at least 300 MVA of fault level (at its connection point). This minimum fault level requirement would reduce to 240 MVA if the generator reduced its capacity 80 MW.
    - This approach is likely to create a practical obligation for synchronous generators. This is due to system strength being a by-product of the generation of electricity and would not require these generators to remain at minimum generation output, or otherwise contract for the periods when they are off-line.
    - For non-synchronous generators, who tend to have low operational capacity factors, this approach may be preferable. This is because they only have to provide system strength at the minimal times when they are operating.
    - This approach would also mean that there is no guarantee that the minimum system strength needs would be met as the quantity of system strength services varies with the dispatch of the generation.
2. **Installed capacity:** the essential level of system strength could be specified in terms of a minimum fault level in MVA per MW of installed generation capacity. That is, all generators would be required to provide a minimum level of system strength at all times in proportion to their total installed capacity.
    - For example, a 3 MVA per MW minimum standard would mean that a generator with 100 MW of nameplate capacity would be required to provide at least 300 MVA of fault level (at its connection point), at all times.
    - Such a large obligation at all times may prove to onerous on generators, particularly for generators those provision of system strength is a by-product energy production. The obligation could be reduced on generators by lowering the standard.
    - This approach may never deliver an efficient level of system strength as the standard is most likely to always over-procure system strength. It may also under-procure system strength at times if the standard is not set at a sufficient level for the system to operate with a high capacity of non-synchronous generation.

Meeting the essential system strength level

The mandatory service provision option envisages that generators who do not inherently meet the essential level of system strength standard may use some combination of:

1. purchasing new equipment (like synchronous condensers) to increase the system strength that they have online while generating

2. entering into an agreement with another generator, or a third party provider, with excess system strength above the minimum standard
3. ceasing to generate when system strength is scarce.

The essential level of system strength standard would create demand from generators that are unable to provide sufficient system strength when they are generating. This demand could be meet by purchasing new equipment, but this may prove to be a more expensive option than entering into an arrangement with another provider of system strength. Also, a third party provider of system strength may be able to provide the service at lower cost by gaining economies of scale and contracting with multiple counterparties.

The economic efficiency of this model is likely to be improved by generators entering into arrangements with one another and with providers of system strength. However, consideration should be given to the following aspects of such an arrangement:

- **Mismatch in generation profiles:** may present some challenges in finding suitable counterparties. That is, wind farms are intermittent in the production of electricity while thermal generators tend to more closely follow demand. This would suggest that contracts for the provision of system strength would be most efficient if they pooled as many buyers and sellers of system strength as possible.
- **Coupling synchronous generation to non-synchronous generation:** through contracts may create some anomalies in central dispatch. At times of high wind output, such contracts may force on synchronous generation to support the wind, thereby resulting in excess generation of energy. In contrast, when a synchronous generator shuts down, it may force off non-synchronous generation.
- **Centralised system strength dispatch:** This type of market may be more operationally efficient with the involvement of a central co-ordinator. If AEMO had central control of ensuring sufficient availability of system strength, it is not clear how dispatch would be co-ordinated across the different generators and system strength providers. The contractual arrangements between participants may need to be undertaken as part of a transparent negotiated process, such that AEMO can determine a basis to prioritise generator dispatch to achieve an economically efficient outcome.
- **Limited contracting opportunities:** The ability of a generator to enter into a contract with another generator in a different region would be limited. For example, in South Australia a minimum level of system strength is required to maintain system security in the islanded region following separation from Victoria. But confining the trading of system strength to within regions may limit competition. This reasoning could also potentially restrict the ability of generators within the same region to contract for the provision of system strength if there was a risk of intra-regional separation. However, the ability to contract between regions and within a region over a longer distance would be limited as system strength is a locational specific service.

There is an open question as to how onerous it would be on AEMO to assess the suitability of any contracting arrangement for system strength due to the issues explored above. From this, it is unknown if it would limit the practicality of being able to contract for system strength in this manner and the practicality of this model.

Applying the obligation to different generator types

A key design consideration of such a model would be the application of the obligation to certain types of generators. The obligation could be restricted to new entrant generators or extended to apply to all existing generators. Equally, the obligation could be restricted to scheduled generators or extended to apply to non-scheduled generators as well.

Treatment of existing versus new entrant generators

To address the immediate challenges to system security in the NEM, the standard would need to apply to at least some existing generators. Restricting the obligation to new entrant generators (and assuming no other model was used) would likely require the system to be heavily constrained to manage system strength. It would also likely be a very reactive option given the current issues the NEM is facing with system strength provision.

Imposing the obligation on existing generators may give rise to situations where generators find it difficult or expensive to meet the obligations. It may also be difficult to determine which specific generators should meet the obligation.

In addition, placing an obligation on existing generators to amend their performance standards may create inconsistencies with their existing connection agreements with NSPs. Connection agreements include the agreed performance standards with respect to each of the relevant technical requirements, which are based on either the automatic access standard or the negotiated access standard for that technical requirement as set out in the NER.

Once a connection agreement is in place, it cannot be varied except as agreed by both parties. If this option were to be pursued, the AEMC may need to investigate other means of imposing the obligation on existing generators through other relevant areas of the NER.

Treatment of non-scheduled generators

An obligation applied only to scheduled generators may not result in the provision of sufficient system strength to maintain system security if a large proportion of demand is supplied through non-scheduled generation sources. An obligation that is restricted to scheduled generators only may not provide sufficient system strength to maintain system security at these times.

Central control of system strength services by AEMO may still not be effective in these instances, as AEMO would be limited in its ability to constrain off the generation being supplied from rooftop solar. The nature and magnitude of the issues of system strength in DNSP networks are explored further in Chapter 6.

4.5.2 Operational considerations

Careful consideration would have to be taken as to how this model is made operational. The core issue to be handled is how each generators remediation assets are co-ordinated effective and efficiently.

Many individual, discrete remediation works being unco-ordinated is an issue identified with the "do no harm" framework. This issue could reoccur under this model if not designed correctly. The result could cause significant issues in the operational timeframe for either, or both, AEMO and TNSPs in their management of the system and network.

4.5.3 Investment considerations

If a mandatory provision model was set at a level that was sufficiently high, this could theoretically provide sufficient levels of system strength. Any shortfall in system strength provision would be linked to any deficiency that exists in the determination, specification, or application of the obligation.

However, the risk of over-investment exists for this model. This is because the fault level requirement of the system will increase as more synchronous generators retire and more non-synchronous generators connect. A constantly changing level of obligation on generators could resolve this issue. Nonetheless, that would significantly decrease investment certainty and not resolve a number of issues raised with the current "do no harm" framework around predictability of costs for new generation.

4.5.4 Benefits of this model

A mandatory service provision model would create greater certainty in the provision of system strength requirements for the power system. This would likely see the power system operate in a less constrained manner and see increased market benefits through the alleviation of system strength constraints.

This model is also more likely to be suitable to provide the essential level of system strength on a consistent basis. It obliges generators to positively contribute to system strength through improved stable operation of inverter-based plant. This, in turn, may be able to assist and / or be co-ordinated with methods to reduce negative inverter interactions.

4.5.5 Downsides of this model

A mandatory service provision model could impose unnecessary costs on newly connecting generators if technical requirements are overly onerous. These requirements' over specification could result in cost inefficiencies for provision of system strength in the long term.

Also, while it can be managed through the framework's design, this model could have other similar issues arise to that of the current "do no harm" framework. This includes contributing to investment uncertainty, generator connection delays, and modelling generator's direct impacts to system strength prior to and during connection processes.

4.6 Model 4: Access standard model — generator performance obligation

BOX 14: SUMMARY OF MODEL

This model describes an obligation on generators to be able to operate stably in low system strength environments. This passive model suggests that generators would only be able to connect to the grid if their equipment, such as inverters and control systems, enables them to operate stably in low system strength environments. However, in contrast to the "active" model, generators would not be required to contribute to the provision of fault current.

- **How to plan for the service?** Planning of this model would be similar to that already undertaken for generators, including the ISP and connection agreement processes.
- **By what mechanism is the service procured? How is the service priced?** The service is effectively "procured" through imposing an obligation on generators to install equipment that is capable of operating stably down to low levels of system strength. This would result in generators procuring equipment that meets the standard with the price set by the cost of doing so.
- **Who pays for the service?** Again, generators would bear the direct costs of this model, and would pass on any increased capital costs through increased wholesale prices.

This model requires generators to maintain stable operation in a power system with lower levels of system strength. That is, this obligation would require connecting generators to have inverters with control systems that do not require high levels of fault current for stable operation. Thought would be required as to what this would mean for existing generators.

Current frameworks do not allow network service providers to require further capability from a connecting generating system, to make efficient use of the available system strength. However, under this model, a generator would be able to remain connected to the grid/market during periods (prolonged and sudden) of low system strength. This model would also allow for the connection of larger volumes of non-synchronous generation to the system, before remediation is needed.

This model can be utilised with any of the other three models explored above to both:

- slow the decline of available system strength levels in certain areas of the grid
- allow non-synchronous generators to be more resilient to sudden or prolonged periods of low system strength.

A similar approach to this was considered as part of the 2018 *Generator technical performance standards* rule change by introducing a new minimum access standard (with no corresponding automatic access standard).[93] This minimum access standard would require each generating unit to be capable of continuous uninterrupted operation for a certain short

93 See: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards.

circuit ratio (SCR)[94] at the connection point. Additionally, AEMO and the NSP would have the ability to negotiate a lower short circuit ratio where appropriate.

4.6.1 Planning considerations

The standard would require generators have the capability of continuous uninterrupted operation for a certain SCR at the connection point. As noted above, a requirement to maintain continuous uninterrupted operation down to an SCR of 3.0 was considered in the 2018 *Generator technical performance standards* rule change. An SCR of 3.0 would allow generators to remain connected (and producing energy) during periods of lower system strength. It also means that generators could operate in a lower system strength environment.[95]

The standard could differ from that proposed by AEMO in 2017 in its rule change proposal to reflect the change in inverter technology and cost over time.

How generators can meet the access standard?

Generators could meet the standard by installing either:

- inverters with the capability to operate stably down to the required of short circuit ratio
- a synchronous condenser behind the connection point.

BOX 15: GENERATOR TECHNICAL PERFORMANCE STANDARDS - FINAL RULE DETERMINATION

The Commission's final rule for the 2018 *Generator technical performance standards* rule change did not contain a new system strength access standard, as the Commission considered that:

- The current system strength frameworks were considered, at the time, to be sufficient to address the risks to power system security from reductions in system strength caused by a range of relatively severe events on the power system or longer term changes in the generation mix.
- The "do no harm" requirement under the system strength frameworks was considered likely to incentivise the installation of generating systems that were capable of continuous uninterrupted operation for the lowest expected three-phase fault level at the connection point.
- It was considered at the time that imposing potential costs or regulatory requirements on a connecting generator in order to help facilitate future connections was contrary to the principles behind the transmission framework in operation in the NEM. Under the current transmission framework, generators are only required to bear the cost directly related to

94 SCR is the ratio of the three-phase fault level (in MVA) at the connection point for a generating system, to the maximum operational level of the generating system (in MW). Strong systems are typically regarded as having a high SCR (>5) and weak systems as having a low SCR (<3).

95 Noting that 3.0 SCR is not necessarily representative of a very low system strength environment.

their connection at the time of their connection. This means that connecting generators do not bear a responsibility for future developments, to the extent that a connecting generator does not create a system security issue for future connections.

- It was considered that the magnitude of the potential benefits had insufficient certainty due to the:
  - incremental costs on all connecting generators today
  - avoided costs for connecting generators and network service providers in future.

Since the final determination of the *Generator technical performance standards* rule was made in 2018, new information has become available that suggests the reasons cited above, and the conclusions reached in that rule change, may need to be reassessed. For example, as discussed throughout this paper, the "do no harm" framework does not appear to have incentivised parties to install inverters that can operate stably down to low levels of SCR.

Similarly, while the shallow connection charging / open access regime remains a central element of the current NEM frameworks, it is also true that significant security benefits could be realised by requiring generators to be capable of maintaining stable operation down to low levels of SCR.

Finally, it is possible that real operational and investment efficiency benefits could be realised through mandating such a requirement, as an ability for non-synchronous generators to remain stable at low levels of system strength could allow more generators to be connected in low strength parts of the system, and potentially delay the need for costly remediation.

4.6.2 Operational considerations

This model may contribute to more secure and efficient operation of the power system. This is because generators should remain connected during short and prolonged period of low system strength.

The model would require another model to operate alongside with it, to make sure that some active provision of fault current occurs. Despite being about how to operate a low system strength levels, inverters would still disconnect from the grid without sustained provision fault current into the power system.

Additionally, a given level of fault current is required for protection systems to operate correctly. Protection systems will not operate correctly under this model alone as it does not obligate the active provision of fault current from any participant.

4.6.3 Investment considerations

This model would not facilitate an active supply of fault current into the power system. As such, this model would not provide the necessary investment in system strength required by the power system for unconstrained output of non-synchronous generation.

It would, however, be able to provide for the power system to have the ability to operate in lower system strength environments. This obligation could in turn reduce the investment required by another model(s), with which this an access standard would work, that would actively provide fault current to the power system.

Therefore, this model would not provide the necessary investment on its own, but could potentially reduce the investment required by another investment in an efficient method.

4.6.4 Benefits of this model

Placing an obligation on generators to maintain stable operation in a low system strength environment may contribute to enhanced system strength resilience across the power system. For example, by enabling inverter connected generators to better manage stability during a disturbance.

Additionally, inverter connected generators that would, by virtue of using less sophisticated control systems, be constrained for system strength, would be capable of providing energy to the market and contribute to increased market benefits.

This model would also provide additional hosting capacity for new generation as it reduces the negative impact non-synchronous generators will have on the local system strength level.

4.6.5 Downsides of this model

This obligation would likely not provide a positive contribution to fault level. Therefore, while this model may contribute to system strength additional investment and or model(s) may be required alongside this model to provide a more complete system strength service.

It also means that this model would not address the issues explored in chapter 2 regarding the current system strength frameworks. It should be noted that the inverters installed due to this standard would provide fault current. However, the obligation wouldn't necessarily increase this requirement. Rather, while the standard reduces the overall system strength requirements, it does not increase total system strength provision.

5 SYSTEM STRENGTH IN DISTRIBUTION NETWORKS

The obligations under the current frameworks are only applicable to TNSPs, except for the occasions where a generator more than 5MW connects in a distribution network. Consequently, the focus of this investigation relates to transmission networks. System strength in distribution networks may also be more appropriately considered separately from the large-scale, high-voltage power system. This is due to the different ways low system strength manifests itself in each network type.

However, low system strength is becoming a growing concern within distribution networks, affecting voltage stability and the performance of inverter connected devices connected to low voltage networks. The Commission welcomes stakeholder insight into the nature, magnitude, and urgency of system strength issues in distribution networks.

This following section provides a brief overview of the Commission's current understanding of system strength impacts in distribution networks.

5.1 Factors that influence system strength in distribution networks

The Commission understands that a number of factors influence system strength within distribution networks. These factors make addressing system strength in these networks a challenge unique from that experienced at the transmission level, and include:

- **Increasing penetrations of rooftop PV:** Distribution networks are experiencing growing penetration of rooftop PV generation and other inverter-based technologies, such as batteries. This may increase the system strength needs of certain parts of the distribution network, especially in localities with particularly dense proliferation of these technologies.
- **Little to no system strength providers exist within distribution networks:** Distribution networks are typically reliant on system strength flow-through from the local transmission network. However, some portions of distribution networks, particularly in regional areas, are electrically distanced from the high-voltage network and are not well serviced by system strength providers on the transmission side.
- **Distribution networks are largely radial, not well-meshed:** This compounds the locality of system strength provision due to the greater prevalence of long, radial electrical pathways, on the end of which may be relatively high density pockets of DER.
- **Low visibility over the behaviour of distribution networks:** As explored in the AEMC's *Economic regulatory framework review* (2019), DNSPs may have low visibility of DER connections in each area, and the voltage and current beyond that measured at zone substations.[96] Determining the system strength needs of different localities using modelling or another means may therefore prove difficult.

96 AEMC, *Economic regulatory framework review — Integrating distributed energy resources for the grid of the future,* 26 September 2019, pp. 114-128.

6 NEXT STEPS

The Commission welcomes engagement from all interested stakeholders in this discussion paper. This chapter sets out ways in which stakeholders can engage with the Commission formally on the contents of this paper. Additionally, stakeholders are welcome to contact the project team to discuss all matters at any time. It also sets out an indicative timeline for this investigation, which is due to be completed by the end of 2020.

The Commission will also be looking to hold a workshop on this discussion paper. It will look to explore the considerations and potential options for system strength further with a wide range of stakeholders to inform how a new framework should be designed. Details will be publicised in the AEMC weekly newsletter, subscribe at aemc.gov.au.

Any enquiries on this investigation can be addressed to James Hyatt on (02) 8296 0628 or james.hyatt@aemc.gov.au.

6.1 Lodging a submission

Written submissions on this discussion paper must be lodged with Commission by **7 May 2020** online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code EPR0076.[97]

A submission template has been provided to assist stakeholders in making their submissions by setting out some specific questions the Commission has regarding system strength. While it is a useful tool for stakeholders, it is not intended to restrict stakeholders' commentary on any aspect of system strength or this paper.

6.2 Indicative timeline to completion

Below is an indicative timeline for the investigation's completion. This is provided for stakeholders information, but may change somewhat throughout the investigation.

Table 6.1: **Indicative investigation timeline**

DATE	MILESTONE
May 2020	Workshop/forum on Discussion paper
	Commence synchronous services market rule change
May–Aug 2020	Public consultation with industry, market bodies and jurisdictions
Sept - Oct 2020	Publish investigation final report and draft rule determination
Oct-Nov 2020	Consultation on draft rule
Dec 2020	Publish final rule

97 The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

A INTRODUCTION TO SYSTEM STRENGTH

This appendix sets out how voltage is managed in the NEM. It is provided for non-technical stakeholders who wish to engage in this review, by assisting understand the basics of system strength service as context for the body of the discussion paper.

A.1 System security services in the NEM

AEMO operates and maintains the power system in a secure operating state. For the power system to remain in a secure operating state, there are a number of physical parameters that must be maintained within a defined operating range. An electricity system that operates outside of these parameters may become unstable, jeopardising the safety of individuals, risk damage to equipment, and increasing risk(s) of blackouts.

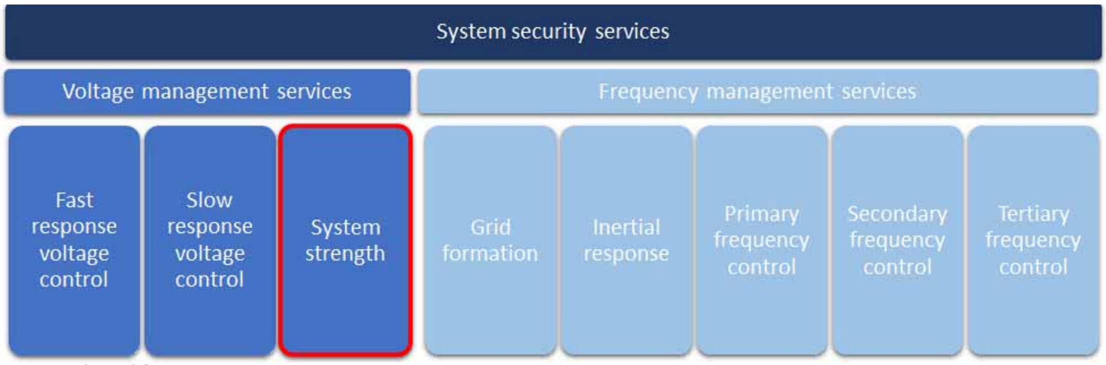
AEMO's management of power system security is influenced by a number of factors. These include the performance of electricity networks, electrical equipment, and generators that are connected to the power system. It also includes the power system security standards set by the Reliability Panel, and the power system security guidelines and procedures set by AEMO.

AEMO manages power system security by using a range of tools, including:

- the operation of the power system, particularly through applying constraints to the dispatch of generation
- market ancillary services - e.g. frequency control ancillary services (FCAS)
- non-market ancillary services - e.g. network support and control ancillary services (NSCAS)
- directions to market participants and clause 4.8.9 instructions that are typically used to instruct a network service provider to shed load.

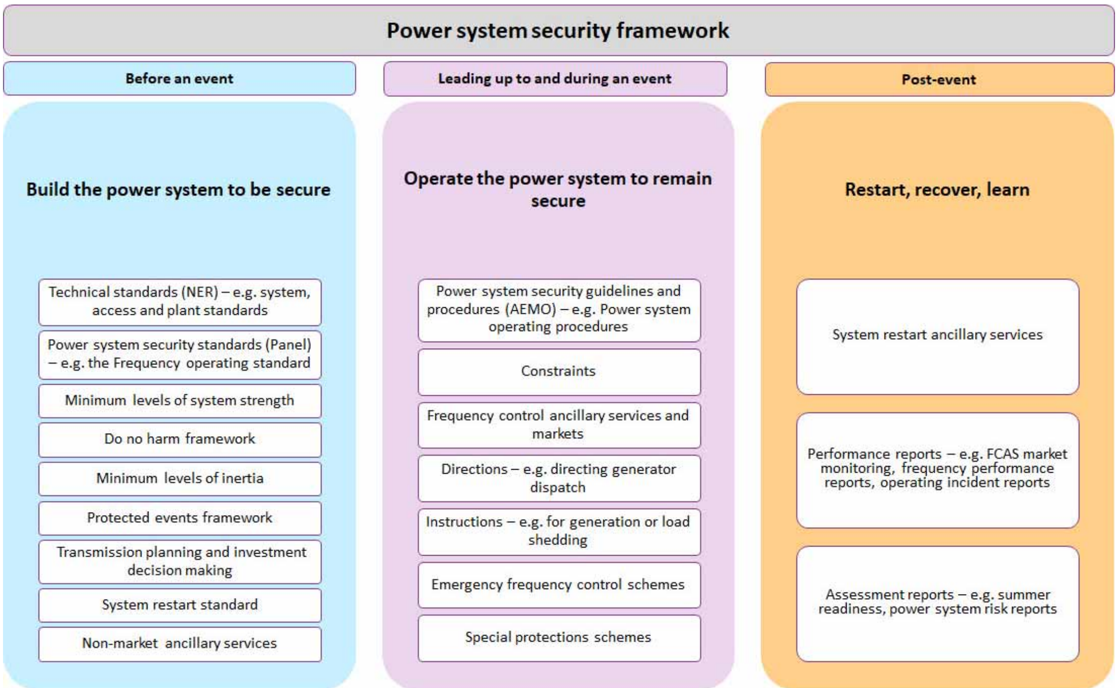
Broadly, power system security services can be categorised as relating to the management of frequency and the management of voltage. This is shown in Figure A.1, which shows how they go together, and Figure A.2, which shows how they work to provide a secure system.

Figure A.1: System security services in the NEM



Source: Adopted from AEMO, Power system requirements.

Figure A.2: How security services work to provide a secure system



Frequency management is a key element of power system security. All generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hertz (Hz). In summary, there are five essential frequency control services being grid formation; inertial response; and primary, secondary, and tertiary frequency control services.[98]

The voltage management services, of which system strength is one, are explored below.

A.2 Voltage management services

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.

Voltage control is managed through the constant balancing of the production or absorption of reactive power. Addressing reactive power imbalances locally, close to where the issue arises, is an efficient and effective way to manage voltage as reactive power does not travel far.[99] In its role as system operator, AEMO:[100]

98 Primary and secondary frequency control services are procured through a combination of technical standards and market sourcing. Tertiary frequency control services are not explicitly procured in the NEM. Instead, AEMO relies on the 5-minute dispatch process to balance supply and demand.

99 AEMO, Power System Requirements, reference paper, p. 17, March 2018.

- co-ordinates available reactive power resources in the network and from generators to maintain voltage levels across connection points in the transmission network and within limits set by network service providers. Reserves are also maintained in credible contingency events.
- Can use additional methods to manage voltage should voltage go outside of the set technical limits, including:
    - Network reconfiguration — the operational switching of transmission elements in and out of service to redirect network flows.
    - Contracts with TNSP's and generators — agreements for specific reactive power support under specific circumstances.
    - Load shedding — automatically or manually turning some (typically large) customers' power off as an emergency last resort.

From this, AEMO as identified three essential services needed to maintain voltages on the network within acceptable limits:

- **Slow response voltage control:** maintains the power system voltage within the required acceptable range as supply and demand change constantly.
- **Fast response voltage control:** is achieved through the provisions of large, rapid adjustments in reactive power to maintain power system stability.
- **System strength:** this service is the focus of this investigation and is explored below.

A.3 Introduction to system strength — what is it?

A Grattan Institute report[101] 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.[102]

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.[103]

100 Ibid.

101 Grattan Institute, *Keep calm and carry on: managing electricity reliability*, February 2019, pp. 29-30.

102 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

103 Ibid.

This includes resisting changes in the magnitude, phase angle, and waveshape of the 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.3.1 How is it 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."[104]

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. Chapter 3 in the body of this discussion paper explores the development of what system strength is since the existing definition was put in place.

A.3.2 How is it different to other system security services?

System strength 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.
- **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.4 System strength services — how are they provided and why is it an issue?

This section sets out how system strength services are provided, why it is being provided less, and why that is an issue for the power system. The current regulatory frameworks for how these services are being procured is set out in Appendix B.

A.4.1 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

104 AEMO, *Maintaining power system security with high penetrations of wind and solar generation,* October 2019, p. 22.

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.4.2 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.[105]

A.4.3 Why do you 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).

105 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

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.[106] The higher the fault level, the higher the response strength to faults in that area.

Table A.1 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	Protection equipment within power systems work to clear faults on only the 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.

106 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

A.5 History of system strength in the NEM

AEMO first identified declining South Australian system strength as an issue in the December 2016 *National Transmission Network Development Plan*.[107] In early December 2016, AEMO announced that at least two large synchronous generating units should be online at all times to maintain system strength in South Australia.

Low system strength issues have become apparent in Victoria and Tasmania since. This demonstrates the challenge system strength will pose in other NEM regions in the near to mid-term. This section sets out the three shortfalls that have been declared by AEMO to date. This being in South Australia, Tasmania and the West Murry region of Victoria.

A.5.1 System strength in South Australia

On 13 September 2017[108] AEMO declared a NSCAS gap[109] in relation to system strength in South Australia through an updated 2016 National transmission network development plan (NTNDP).

Transitional arrangements were introduced in the final rule[110] that afforded AEMO the flexibility to withdraw the NSCAS gap, and reissue it as a fault level shortfall. AEMO subsequently withdrew the NSCAS gap, and reissued it as a fault level shortfall after the commencement of the final rule, which allowed the gap to be treated as a fault level shortfall under the new final rules.[111]

Following the issuing by AEMO of the fault level shortfall in South Australia, ElectraNet, the transmission network service provider in South Australia, was obligated to remedy it by procuring system strength services. ElectraNet evaluated potential options for addressing the shortfall. Their analysis identified:[112]

- contracting with synchronous generators to meet the shortfall would not be economic
- installing synchronous condensers was the least cost option
- there were no other options available in the required timeframe.

ElectraNet sought offers from market participants in South Australia to meet the minimum system strength requirements but ultimately determined that generator contracting was not an economically viable solution. Instead, it proposed not to meet the shortfall, and that AEMO should continue with directing generation in the short term.

ElectraNet suggested that fast-tracked investment in synchronous condensers would be the most efficient solution in the medium term. As at May 2018, ElectraNet envisaged that the

107 AEMO, *National transmission network development plan,* December 2016.

108 Six days prior to the publication of the *Managing power system fault levels* final rule

109 The NER has a framework for addressing NSCAS gaps. NSCAS gaps are shortages of services that can be provided by a network, e.g. a shortage of reactive power provided in a part of the network. NSCAS gaps can either be for system security, reliability or market benefit. Where a gap is declared, the relevant TNSP has the option of deciding to meet the gap or not. If the TNSP elects not to, and the NSCAS gap is for security or reliability, AEMO can meet the gap as a procurer of last resort.

110 *National Electricity Amendment (Managing power system fault levels) Rule 2017*

111 AEMO, *Second update to the 2016 National transmission network development plan*, October 2017.

112 ElectraNet, *Power system strength: information sheet*, May 2018.

synchronous condensers would be constructed and commissioned "by 2020".[113] ElectraNet liaised with the AER and AEMO during this process.[114]

In February 2019, ElectraNet published a supplementary report that assessed the options by economic evaluation. The three options considered were:

- continued reliance on AEMO directions to ensure adequate system strength,
- generator contracting, and
- installation of high inertia synchronous condensers.

ElectraNet concluded that the economically preferred option was to install synchronous condensers.[115]

ElectraNet's report estimated the cost of contracting with generators to be $85 million per annum, while the cost of directions was estimated at $34 million per annum. However, the report noted that the $34 million "excludes the broader impact of intervention pricing on wholesale market prices ... which represents an additional cost ultimately borne by customers. AEMO estimates the cost impact of intervention pricing on wholesale market outcomes as a result of issuing directions for system strength as at September 2018 exceeds $270m. This is additional to the impacts of constraining wind generation."[116]

ElectraNet's Transmission Annual Planning Report 2018 noted that the generator contracting option, with a cost of $85m pa, could also entail additional costs. It noted: "under this option, there would also remain a potential need for generator direction with its associated costs once the volumes and unit combinations offered by tenderers had been exhausted, and a potential for negative pool price exposure, both of which would add further costs to this option. These additional costs have not been included in this assessment."[117]

A.5.2 System strength in Tasmania

The National Transmission Network Development Plan (NTNDP), published in December 2018, included an initial assessment of inertia and system strength in the NEM. The NTNDP noted that Tasmania was projected over 5 years to meet their minimum regional fault level and inertia requirements.[118]

However, on the 13 of November 2019 AEMO published an inertia and fault level shortfall notice for Tasmania. AEMO has assessed both synchronous unit dispatch projections for the Tasmanian region in conjunction with fault level projections. AEMO has determined that synchronous units are likely to experience lower levels of dispatch leading to a projected inertia level shortfall. In addition, shortfalls are projected at several other fault level nodes.

113 ibid.

114 In its Quarterly Compliance Report for the first quarter of 2018, the AER stated: "Based on the information provided, ElectraNet has demonstrated that it took reasonable steps to economically assess and make available the least cost option to provide system strength services through first seeking offers for these services from market participants and ultimately proposing the synchronous condenser solution, in accordance with clause 5.20.3C(1) of the Electricity Rules". See AER, *Quarterly Compliance Report: National Electricity and Gas Laws, 1 January - 31 March 2018*, p. 18.

115 ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, February 2019.

116 ibid, p. 21.

117 ElectraNet, *South Australian Transmission annual planning report*, p. 87.

118 AEMO, National Transmission Network Development Plan, pp. 16 18, December 2018

System strength and inertia have historically been provided in Tasmania by the existing hydro-electric fleet. These services have been provided as a by-product of synchronous unit dispatch by the market or by Hydro Tasmania voluntarily operating its units in synchronous condenser mode to maintain the minimum levels during periods when the number of synchronous hydro generator units online was low.[119]

Tasmania has the potential to experience low levels of critical system security services during periods of low synchronous unit commitment. This is most likely to occur during periods of low demand combined with times when Basslink is experiencing high imports.[120]

Low fault level conditions align with low commitment of synchronous plant in Tasmania. AEMO has reviewed fault level projections for the Tasmanian region and projects a fault level shortfall at the fault level nodes of George Town (530 MVA), Burnie (180 MVA), Waddamana (310 MVA) and Risdon (320 MVA). [121]

AEMO and TasNetworks have agreed on a date of 1 April 2020 by which time inertia or system strength services should be available to meet the relevant shortfall. To date TasNetworks have completed a Request for Expressions of Interest initiating the process of obtaining system strength and inertia services in Tasmania.

A.5.3 System strength in West Murry

The West Murray zone is an area bounded by Ballarat, Dederang, and Darlington Point and is considered to be an electrically weak part of the NEM. Despite this, the area has received notable investment in large scale solar and wind generation. AEMO note that the scale and pace of inverter based renewable generators connecting in this zone have resulted in technical issues impacting grid performance and operational stability.[122]

The West Murray zone has a low capacity transmission network, is a long distance from major load centre (~500km), has a high density of inverter based generation and is electrically distant from conventional sources of system strength.[123]

In order to maintain system security AEMO has reduced the number of online inverters and the output from five solar farms in the West Murray zone to a level that reduces the occurrence of oscillations should a fault occur.[124]

AEMO has identified additional short, medium and longer term solutions to manage the issues identified in the West Murray zone. These include:

119 AEMO, Notice of inertia and Fault level short falls in Tasmania, p. 6, November 2019.
120 ibid p. 3.
121 ibid, p. 16.
122 AEMO, West Murray Technical Forum, slide pack, February 2020.
123 AEMO, West Murray Technical Forum, slide pack, February 2020.
124 AEMO, Power System limitations in North Western Victoria and New South Wales, p. 7, December 2019

- *Short term (early 2020)* - Tuning and testing the five constrained solar generators to adjust the performance of their systems to operate securely with increased output in the low system strength environment.[125]
- *Medium Term (January 2021)* - declaration of a system strength shortfall of 312 MVA of three-phase fault current at the Red Cliffs terminal station. Closing this gap will allow inverter based generators to increase output without breaching oscillatory stability limits.
- *Longer term* - Significant network augmentation is required to completely remove limitations, including thermal limitations, in the West Murray region.[126]

In addition to system strength limitations, two additional power system limitations are emerging in West Murray. These relate to thermal and voltage stability.

West Murry has reached its thermal network transfer limit of 1,700MW.[127] AEMO report that the current installed and commissioned generation in the West Murray zone is 1,700MW.[128]

Studies relating to voltage stability are ongoing in relation to the loss of the Ballarat to Ararat 220 kV line in north west Victoria. Results indicate power system security issues with greater than 600 MW of generation tripping. Initial constraint equations[129] have been implemented to manage this issue in December 2019. AEMO has modified its tools to monitor this condition and is furthering its analysis to refine, and potentially lift, these limits.[130]

System and equipment modifications may relieve constraints on operational plant in the near term. However, the thermal and stability power system limitations will likely continue to prevent projects from connecting or generating at full output, in the absence of significant investment in network augmentation.

125 AEMO has also postponed final approvals from new generators due for commissioning or registration in the impacted area until new operating parameters are verified, approved and implemented by the solar plants.

126 The Western Victoria Renewable Integration Project and Porject Energy Connect are two major projects expected to be delivered in the west Murray Region in the Next 5 years.

127 This figure represents a limit under ideal conditions. At higher temperatures this limit will decrease.

128 An additional 1200MW and 3000MW of inverter-based generation projects are in the pre-commissioning and application phase respectively.

129 A constraint of 600 MW on generation connected between Horsham and Ballarat.

130 AEMO, Power System limitations in North Western Victoria and New South Wales, p. 9, December 2019.

B OVERVIEW OF THE SYSTEM STRENGTH FRAMEWORKS

This appendix provides an overview of the system strength frameworks, namely the "Do no harm" obligation on new connecting generators and the minimum level of system strength rule.

On 19 September 2017, the Commission published the *National Electricity Amendment (Managing power system fault levels) Rule 2017* ("system strength rule") and the *National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017* ("inertia rule") in response to rule change requests submitted by the South Australian Government.

The final rules were deliberately designed to mirror each other such that the requirements for the identification of shortfalls and the procurement of system strength and inertia requirements were services were largely identical. The rule required:

- AEMO to develop system strength and inertia requirements methodologies. AEMO was to use these methodologies to determine the required:
  - three-phase fault level at key locations in each transmission network necessary for the power system to be maintained in a secure operating state
  - inertia necessary to maintain any sub-network in a secure operating state.
- After determining the system strength and inertia requirements in a region, AEMO to identify any region where there was a system strength or inertia shortfall and declare a shortfall in that region.
- The relevant TNSPs to procure system strength or inertia services needed to meet the required level as determined by AEMO where a system strength shortfall or inertia shortfall had been declared. These services are then enabled operationally by AEMO as needed.

In relation to system strength specifically and new connections, the system strength rule required:

- AEMO to develop system strength impact assessment guidelines that set out a methodology to be used by NSPs and generators when assessing the impact on system strength of a new generator connection.
- new connecting generators to "do no harm" to the security of the power system. This means new connecting generators should not adversely impact on the ability to maintain system stability or on a nearby generating system's ability to maintain stable operation.[131]

Therefore, the system strength rule established two frameworks for addressing the causes of system strength issues:

1. An **increase** in the amount of system strength needed as new generators connect to the system - the "do no harm" obligations on new connecting generators.

131 This requirement applies regardless of whether AEMO has declared a system strength shortfall in a region.

2. A **decline** in the amount of system strength typically provided by existing generators - the minimum system strength framework.

These two frameworks are explored below.

B.1 "Do no harm" obligations on new connecting generators

The "do no harm" requirements for new connecting generators commenced on 17 November 2017. This coincided with a requirement on AEMO to publish an interim set of system strength impact assessment guidelines. In accordance with the final rule, AEMO consulted on and published a final set of these guidelines by 1 July 2018.

The final rule places an obligation on new connecting generators to "do no harm" to the level of system strength necessary to maintain the security of the power system.[132]

The "do no harm" framework requires that new entrants undergo a system strength impact assessment is undertaken using the methodology and power system model set out in the system strength impact assessment guidelines developed and published by AEMO. These guidelines specify what AEMO considers to be an "adverse system strength impact", i.e. "doing harm". They also provide guidance on the different network conditions, dispatch patterns and other relevant matters that should be examined when undertaking an assessment.

A dispute resolution mechanism was put in place which allows a new connecting generator to dispute the application of the system strength impact assessment guidelines, whether the model used in the assessment of the system strength impact was reasonably appropriate, or the results of a system strength impact assessment made using those guidelines.[133]

The new connecting generator is required to fund the provision of any required system strength connection works or remediation schemes to address the impact of its connection on system strength. This places an incentive on new connecting generators to either design their systems to operate at lower levels of system strength or to connect at locations within the network where there is sufficient system strength.

The obligation on new connecting generators only applies at the time the connection is negotiated, based on the information available at the time. Once established, the obligations are incorporated into the connection agreement between the generator and the NSP.

This new requirement has resulted in new connecting generators spending considerable amounts on remediation works, and experiencing delays related to reaching agreement on the scale of works required, procurement and commissioning.

The regions where non-synchronous generation output constraints are being imposed due to inadequate system strength (e.g. South Australia) currently have no generators connected to the network that have remediated their connection impact under the "do no harm"

132 The "do no harm" obligation applies to generators connecting to both the transmission network and distribution network under Chapter 5 (i.e. under rule 5.3 and rule 5.3A) of the NER. It does not apply to the connection of micro-embedded generation, such as residential solar.

133 Clause 5.3.4B(d) of the NER.

framework. We understand that, if generators have remediated their impact under that framework, they would not be included in the non-synchronous dispatch constraints used by AEMO.

B.2 Minimum level of system strength

The intent of the minimum system strength framework is to make sure there is sufficient system strength in the power system to maintain secure operation.

Under the final rule, an obligation was placed on AEMO to develop a methodology ("system strength requirements methodology") that sets out how it will determine the system strength needed in each region ("system strength requirements"). When AEMO specifies the system strength requirements for a region, it must define this in terms of:

- the "fault level nodes" in the region, being the location on the transmission network at which the fault level must be maintained at or above a level determined by AEMO
- for each fault level node, the minimum three phase fault level.

Clause 5.20.2(c)(14) currently requires the NTNDP[134] to describe:

- the system strength requirements for each region,
- details of AEMO's assessment of any fault level shortfall, and
- AEMO's forecast of any fault level shortfall arising at any time within a planning horizon of "*at least* 5 years" (emphasis added).

In each region, AEMO has selected fault level nodes based on four criteria: areas near metropolitan load centres, synchronous generation centres, areas with high levels of non-synchronous generation connection/interest, and areas which are electrically remote from synchronous generation.[135]

Following the determination of system strength requirements for each region, AEMO must undertake an assessment of any fault level shortfall. In assessing the extent of a fault level shortfall, AEMO must have regard to typical patterns of centrally dispatched generation. Clause 5.20C.2 requires the following:

> (a) *AEMO* must as soon as practicable following its determination of the system strength requirements for a region under clause 5.20C.1 assess:
>
> > (1) the *three phase fault level* typically provided at each *fault level node* in the *region* having regard to typical patterns of *dispatched generation* in *central dispatch*;
> >
> > (2) whether in *AEMO's* reasonable opinion, there is or is likely to be a *fault level shortfall* in the *region* and *AEMO's* forecast of the period over which the *fault level shortfall* will exist; and

134 Under the ESB's Actioning the ISP process, this will be removed to a separate report on system strength. [check and update when actioning the ISP rules are published]

135 AEMO, *System Strength Requirements Methodology*, June 2018, p. 15.

> (3) where *AEMO* has previously assessed that there was or was likely to be a *fault level shortfall*, whether in *AEMO's* reasonable opinion that *fault level shortfall* has been or will be remedied.
>
> (b) In making its assessment under paragraph (a) for a *region*, *AEMO* must take into account:
>
> (1) over what time period and to what extent the *three phase fault levels* at *fault level nodes* that are typically observed in the *region* are likely to be insufficient to maintain the *power system* in a *secure operating state*; and
>
> (2) any other matters that AEMO reasonably considers to be relevant in making its assessment.

If AEMO assesses that there is, or is likely to be, a shortfall, it is required to publish a notice and give it to the relevant TNSP. This notice must specify the extent of the fault level shortfall and the date by which the TNSP must provide services to address the shortfall (the services to address the fault level shortfall are "system strength services"). This date must not be earlier than 12 months after the notice is published (unless otherwise agreed), to provide the TNSP with sufficient time to make the services available.

Following receipt of a notice from AEMO declaring a shortfall, the TNSP must make system strength services available to AEMO in accordance with the specification in the notice. Clause 5.20C.3 provides:

> (b) If *AEMO* gives a notice under clause 5.20C.2(c) that AEMO has assessed that there is or is likely to be a *fault level shortfall* at a *fault level node* in a region, the System Strength Service Provider for the region must make system strength services available in accordance with paragraph (c) that when enabled will address the *fault level shortfall* at the relevant *fault level node*.
>
> (c) For the purposes of paragraph (b), a System Strength Service Provider for a region must:
>
> (1) use reasonable endeavours to make the system strength services available by the date specified by AEMO in the notice under clause5.20C.2(c);
>
> (2) make a range and level of system strength services available such that it is reasonably likely that system strength services that address the fault level shortfall when enabled are continuously available, taking into account planned outages, the risk of unplanned outages and the potential for the system strength services to impact typical patterns of dispatched generation in central dispatch; and
>
> (3) maintain the availability of those system strength services until the date the System Strength Service Provider's obligation ceases, as specified by *AEMO* under clause 5.20C.2(d).

> (d) A System Strength Service Provider required to make system strength services available under paragraph (b) must make available the least cost option or combination of options that will satisfy its obligation within the time referred to in subparagraph (c)(1) and for so long as the obligation to make the system strength services available continues.

As can be seen, the requirement to *make the services available* by the date specified by AEMO in the notice is a "reasonable endeavours" obligation.[136] However, the obligation *to provide the services* is not expressed as a "reasonable endeavours" obligation. Rather, it is an unqualified obligation to provide the services to address the shortfall identified by AEMO.[137] This issue is discussed further below in section 3.4.2.

The TNSP is not required to undertake a regulatory investment test (RIT-T) for the relevant transmission investment if both:[138]

- AEMO requires the system strength services to be provided less than 18 months after the publication of the notice
- the TNSP is not already under an obligation to provide system strength services for that fault level node.

This shortens the process by which the TNSP assesses the combination of operational expenditure (e.g. contracting with synchronous generators) and network expenditure (e.g. building a fault level source on the network) that best addresses the shortfall within the 18-month timeframe. This provision is further discussed in section 3.4.2.

Once the TNSP procures the necessary system strength services, the operational control of the services is passed to AEMO to manage the security of the power system in that region, consistent with its obligations under the NEL.

136 Clause 5.20C.3(c)(1).

137 Clause 5.20C.3(b), (c)(2) and (d).

138 Clause 5.16.3(9) and (11).

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
DER	Distributed Energy Resources
DNSP	Distributed Network Service Provider
ESB	Energy Security Board
GW	Gigawatt
ISP	Integrated System Plan
MVA	Mega Volt Amp (Apparent power)
MVAr	Mega Volt Amp Reactive (Reactive power)
MW	Megawatt (Active power)
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NGL	National Gas Law
NGO	National gas objective
NSP	Network Service Provider
TNSP	Transmission Network Service Provider
VRE	Variable Renewable Energy