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ESSENTIAL SYSTEM SERVICES IN THE NATIONAL ELECTRICITY MARKET

A REPORT FOR THE ENERGY SECURITY BOARD (ESB)

FINAL REPORT

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Executive summary

1. In common with most electricity systems in the world, the Australian National Electricity Market ("**NEM**") has entered a period of transition as the share of generation from variable renewable generation ("**VRE**") increases rapidly. The system now operates with an increasing share of non-synchronous generation (inverter-based resources ("**IBR**"), such as wind and solar) and a declining share of conventional large-scale synchronous coal and gas-fired generation. By 2025, the maximum penetration of wind and solar is expected to exceed 75% of underlying demand and could reach up to 100% according to different AEMO forecasts.[1]

2. These trends have increased the variability and uncertainty of supply while simultaneously increasing the sensitivity of the system to disturbances. They are manifesting themselves in **growing ramps** (fluctuations in net load), **falling system inertia** (the measure of resilience of the grid to frequency changes), **deteriorating frequency performance** (wider distribution of the excursions outside of the "normal" frequency band) and **weakening system strength.** Moreover, AEMO is expecting these issues to become even more acute in the coming years.

3. It is becoming increasingly apparent that many essential system services ("**ESS**", or ancillary services) which are necessary for the secure operation of the NEM are currently provided without explicit compensation as a **by-product of energy** supplied by synchronous generators (e.g. system strength and inertia). The progressive retirement of these generators has led to a falling provision of some of these services, which now poses a **risk to the security of electricity supply** in the NEM.

4. In light of these growing challenges, the current ESS arrangements in the NEM may need to evolve, both in terms of **procuring** the services (i.e. ensuring that adequate resources exist to provide the services, some of which may need to be constructed) and in terms of **scheduling** them (i.e. dispatching existing resources in real time ("**RT**")).

5. In this context, the Energy Security Board ("**ESB**") has been requested by the Council of Australian Governments ("**COAG**") to undertake a preliminary development of potential fit for purpose Post 2025 Market Design frameworks. To assist with one strand of this work, FTI Consulting has been commissioned by ESB to examine options for the procurement and scheduling of ESS in the NEM that would be in the long-term consumer interest. This report sets out our findings.

6. In our report, we first identify those ESS where the case for change appears to be the strongest. We then present options for changing the procurement and scheduling of ESS and assess their merits against principles that seem most likely to represent good policy outcomes. We also consider how the wider regulatory framework may need to adapt to deliver those changes. Finally, we present a potential roadmap towards the Post 2025 Market Design in the NEM. We provide a summary of our key findings below.

Case for change to ESS

7. The urgency of considering potential changes to the current ESS arrangements depends on whether the existing frameworks are fit for purpose to meet the current and future system needs. The case for change appears strongest where the current framework fails to provide operational and/or investment signals, where it fails to deliver security of supply or where future trends are expected to exacerbate emerging challenges to the security of supply. In this report, we focus on the following categories of system services:[2]

   - **Inertia** and **system strength** are both currently procured with no explicit remuneration and without any coordination in real time. They therefore face a high risk of significant shortfalls and hence have the strongest case for change.
   - **Frequency response** is provided via a structured process (Frequency Control Ancillary Services ("**FCAS**")), but some price signals could be strengthened (e.g. for mandatory primary frequency response), or specific FCAS categories could be refined to better meet future needs (e.g. faster response), meaning there is also a strong case for change.
   - There may also be a case for changing the current reliance on in-market provision of **operating reserves** (i.e. without an explicit product) – the decision would hinge on the trust that the market will continue to self-procure a sufficient volume of reserves.

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1 AEMO, Renewable Integration Study: Stage 1 report, 30 April 2020 (link), page 6.

2 Other services, such as voltage control, have a less acute need for change, while the consideration strategic reserves is closely tied to the Resource Adequacy Mechanisms analysis examined in a separate FTI report - Resource Adequacy Mechanisms in the National Electricity Market. A Report for the Energy Security Board, 2020.

8. One feature of ESS is that they are, to varying degrees, partial substitutes of each other, so that the provision of one service may (or may not) reduce the need for another service. Multiple ESS may also be provided by a single resource simultaneously. This means that the cost of providing the ESS may be lower if some of the system services and energy are considered jointly ('co-optimised'). For example, as inertia and system strength are often (although not always) provided as a by-product of energy, and therefore may need to be considered jointly to minimise costs to consumers.

Options for procuring and scheduling ESS

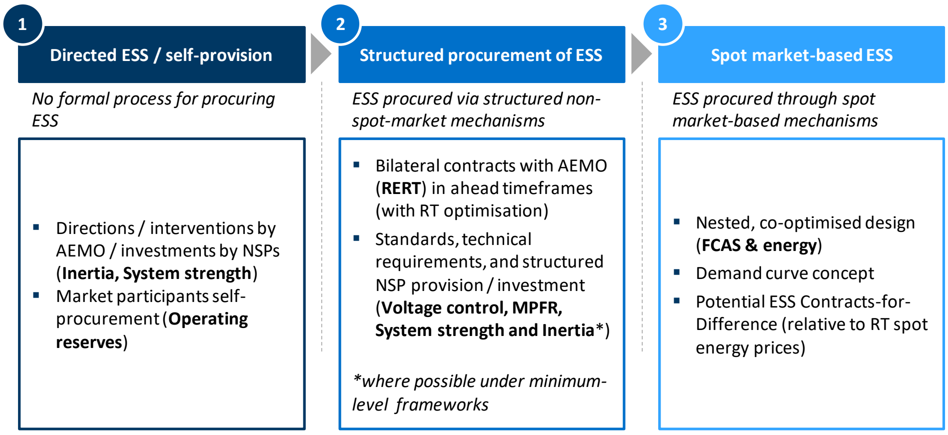
9. There is a wide range of potential approaches for procuring and scheduling ESS. In our report we define a series of high-level design dimensions (e.g. degree of co-optimisation, locational granularity, centralised or decentralised procurement and the approach to resource commitment) and a range of specific parameters (e.g. quantitative targets for procurement, eligibility criteria for providers) to derive three broad approaches for the procurement of ESS, described below and summarised in Figure E-1.

10. The first broad approach is somewhat **ad-hoc** in nature. It relies on either the self-provision of a service by market participants given market incentives (which is the current approach adopted for operating reserves), or direct interventions in the market by AEMO (or investments by NSPs) in response to an actual or perceived shortfall of a service (which is the current approach adopted for inertia and system strength).

11. The second broad approach formalises the (previously ad-hoc) procurement and scheduling through **structured (but not spot-market) mechanisms**. Instead of merely reacting to a service shortfall, AEMO or NSPs would take action to ensure that resources were available to provide system services. This could take the form of bilateral contracts between resources and AEMO/NSPs, or of a physical investment by NSPs, subject to relevant investment tests. A key feature of this approach is that it can be used to form a price for individual system services and pay that price to all resources providing the service in the relevant period. This would ensure that (1) services are no longer treated as being provided 'for free', and that (2) resources are treated equally, subject to relevant technical and commercial characteristics. In this approach, relevant authorities may also set technical and performance standards, e.g. to mandate that resources be technically capable of providing certain services, or to mandate standards that ensure resources are able to operate in environments with lower levels of a particular service (e.g. low inertia).

12. The third approach involves the development of **spot markets for individual system services**, where resources bid to provide the service. In this design, the quantum of need for relevant services is explicitly articulated through “demand curves”, which express AEMO’s willingness to pay for increasing levels of a particular system service. Conversely, suppliers’ bids define a supply curve for the service, such that the intersection of the demand and supply curves determines the spot market price through paid to resources providing the service. The RT spot market provides a price signal that could support both investment and/or operational unit commitment decisions.

Figure E-1: Overview of current ESS procurement and scheduling options



The spectrum of procurement options for ESS, with identification of current provision mechanisms in bold. Source: FTI analysis

13. In considering the merits of each approach, a particular concern with the **first approach (directed ESS / self-provision)** is that the ad-hoc manner in which the service is procured is unlikely to provide investment signals to market participants. Also, in the short run, the ad-hoc nature of procurement may mean that more efficient ways in which the service might be provided are not considered. Both impacts are likely to increase costs to customers.

14. The key advantage of the **second approach (the structured procurement of ESS)** is that it gives AEMO greater confidence that it will be able to operate the system in a secure and reasonably efficient manner. This is because it ensures, contractually or through a regulated investment, that a sufficient volume of resources is available to provide ESS. In addition, this approach remunerates some of the resources providing the system service, thus moving away from the arrangements where certain services (e.g. inertia and system strength) are usually provided “for free” as a by-product of another service (e.g. energy).

15. In practice, it seems very challenging to implement this approach efficiently because it requires AEMO and/or NSPs to specify ex-ante the volume and the price of the service required, both of which are highly uncertain, as well as select the resources ahead of time. There is therefore an inherent risk that services are procured sub-optimally (e.g. too much service, and/or services at an excessive price), to the detriment of consumers. In addition, the price signal arising from this approach is limited, as only a subset of resources are remunerated for the services they provide (those with a contract or regulated revenue). Finally, the different revenue stream and risk profiles make it difficult for market-based ESS providers to co-exist alongside those that have access to regulated revenue streams.

16. Finally, the third approach (**spot market demand curves for ESS**[3], which express the willingness to pay for different levels of service), has three key advantages relative to the second approach of procuring a pre-defined quantum of a service.

   - First, it reflects AEMO's willingness to pay higher prices at times when the supply of a service is close to the minimum requirements.
   - Second, it could reflect AEMO's willingness to pay for a higher quantum of a service under certain conditions. For example, AEMO might find it in customers' overall interest to procure a higher volume of reserves if it forecasts potential high net load swings (e.g. under high wind generation), or it may be willing to pay for additional services that would increases grid resilience to multiple contingencies or less credible contingencies.
   - Third, the spot market demand curves would provide a transparent price signal to market participants to make investment and/or unit commitment decisions, which can in turn incentivise additional cost efficiencies and innovation.[4] This should result in lower consumer costs in the long run.[5]

17. The analysis in our report indicates that operating reserves and frequency control could be well suited to a spot-market-based procurement in the near future. This is less certain, at least in the short run, for synchronous services such as inertia and system strength. Alternative options could be considered for these two services, where AEMO may be able to run a "back-up" commitment process that would involve a degree of competition among resources (as proposed through a Power System Security Ancillary Services Market or "**PSSAS**").

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[3] There may also be ahead market demand curves, in addition to the spot market ones.

[4] In addition, the spot price can serve as the reference price against which any potential contracts-for-difference for ESS (contracted for ahead time) are settled.

[5] These cost savings would need to be compared to the costs of implementing this market design option. This is the case for all options considered in this report.

Regulatory framework

18. A long-term regulatory framework for ESS needs to balance a number of sometimes conflicting objectives and, in particular, manage the fact that the incentives that AEMO and NSPs face in procuring ESS do not necessarily always align with consumer interest.

19. The central issue in operating a secure power system is that any system security failures are easily observable, whereas overspend on system security is highly opaque due to the **asymmetry of information** between regulators and the parties incurring the costs. This leads to an understandable bias towards conservativeness by system operators in running the system, and a tendency towards investing in network (rather than non-network) solutions by NSPs, both of which might lead – if unchecked – to investments that are not cost-efficient.

20. One way to deal with this is to impose a detailed set of rules on the relevant decision makers, in order to constrain their ability to overspend on ESS. However, this kind of **regulatory "straitjacket"** is unlikely to align fully with consumer interest because insufficient flexibility would fail to stimulate innovation and would not allow ESS procurement to adapt and meet the evolving system needs in a timely manner.

21. Alternatively, the regulatory regime could allow the relevant decision makers to exercise their discretion in an unfettered manner, but this may lead to **"too much" flexibility** in procuring ESS, as it is difficult for regulators to monitor and police these decisions (notwithstanding any attempts to set up incentives for the parties to behave in a manner that is aligned with consumer interest). This in turn could lead to unnecessary costs being incurred and ultimately paid for by consumers.

22. A balance between these two ends of the spectrum may be, in practice, most acceptable to a broad range of stakeholders. In any event, any flexibility or discretion that decision makers (AEMO, NSPs or others) may be given needs to be supported by a range of **checks and balances** to mitigate the downside risks associated with that flexibility. These checks and balances may include refinements to the commercial incentives faced by AEMO or NSPs (or operation under the oversight of independent bodies such as the Reliability Panel), enabling flexibility within a controlled environment (such as testing and trialling), transparency requirements, the expectation that any exercise in flexibility would ultimately need to be formalised (albeit ex-post), strengthening the regulatory oversight by imposing cost controls (on potential providers of ESS to AEMO) or refining the RIT-T-type tests.

Roadmap for the NEM

23. The roadmap for operationalising a new ESS procurement and scheduling framework assumes that NEM will continue evolving towards a VRE/IBR-dominated world, with an unknown mix of other resources and perhaps technologies used to meet balancing needs.

24. At one end of the options spectrum, a progressive development approach can be considered, where each new system service is developed and added on an as-needed basis. At the other end of the spectrum, a one-off introduction approach would enable a coordinated introduction of multiple services simultaneously. Both approaches have some disadvantages: the progressive approach risks creating a siloed approach, or a path dependency where the initial decisions make the final outcomes suboptimal, or risks leading to inconsistent market design elements. Conversely, the one-off approach may delay changes (driven by the "lowest common denominator") or lead to undesirable outcomes (and unintended consequences) if everything is changed at once, thus increasing consumer costs.

25. A balanced approach would seek to develop as much of the long run design as feasible, but distinguish between changes to the design that are efficient to implement in tandem, and those that are less closely linked together and therefore can be implemented on a separate timeline. We, however, recognise that this may be complex, as identifying which design elements interact so strongly that they need to be developed together and which can be developed separately without much loss in efficiency or performance involves a degree of subjectivity.

26. One potential roadmap for the NEM would involve prioritising the most urgent changes to ESS (see paragraph 7 above). The most urgent ESS, which are also less intertwined with other ESS, could be implemented before progressing towards the less urgent (and more complex) ones.

    - First, a spot market (and the underlying demand curves) for Operating Reserves and FCAS could be defined across one or all NEM regions, while inertia and system strength would remain under the status quo (or possibly move to a PSSAS-type regime).
    - Second, a spot market for inertia could be initially developed in region(s) where this is most urgent (e.g. South Australia), and extended to other regions if and when appropriate.[6]

[6] For the second, third and fourth area of change, regions without an explicit demand curve for inertia and/or system strength would involve a PSSAS-type commitment process as a back-up.

- Third, a spot market for system strength, to support more VRE, could be initially developed in region(s) where this is most urgent (e.g. South Australia or Victoria), and extended to other regions if and when appropriate.
- Fourth, a spot market for system strength could be extended to also cover the minimum requirements.

27. However, not all the stages set out here would necessarily be implemented in the NEM by 2025 or even in the longer term. We envisage that before embarking on each stage, an impact assessment would be undertaken to consider relevant implementation issues and assess whether the continuation to the next stage is feasible and warranted. This process would be informed by the learnings from the previous stage(s) and based on the relevant principles for ESS procurement, as discussed in Section 4.

1. Introduction and background

Background and purpose of report

1.1 In common with most electricity markets in the world, the Australian NEM[7] has entered a period of transition as the share of generation from VRE, notably solar and wind generation, increases rapidly. At the same time, the demand for electricity is also evolving, driven by factors such as decentralisation of generation and storage, digitalisation and deployment of electric vehicles.

1.2 Electricity systems need to maintain a balance between demand and supply in order to keep the overall system frequency within certain parameters. Historically, when most generation was provided by large-scale dispatchable plants such as coal-fired and gas-fired generation, the main challenges of maintaining such balance were driven by the need to reliably forecast demand and supply, and by the risk of an unexpected imbalance if one the large plants connected to the system tripped or if there was an outage on the transmission networks.

1.3 The system now operates with a supply mix that is increasingly variable and uncertain as a result of the growth in VRE such as wind and solar. The growth of distributed, behind-the-meter resources has also increased the uncertainty and variability of net demand, making the continuous balancing of the system even more challenging than in the past.

1.4 This increase in supply of solar and wind, which are inverter-based resources, combined with the progressive withdrawal and retirement of synchronous generators (such as coal and gas plants), has driven higher sensitivity to disturbances due to a reduction in system inertia. It is becoming increasingly apparent that many system services necessary for secure operation, including system strength and inertia, have been provided without explicit compensation as a by-product of the bulk energy being supplied from synchronous generators.

[7] The NEM covers five regions: Queensland, New South Wales, Victoria, South Australia and Tasmania.

1.5 The provision of these services, known in the NEM as ancillary services or ESS, is essential to ensure the system operator ("**SO**") is able to balance the power system, to keep it within technical operating limits and to deliver security[8] and reliability[9] in the NEM. Although not all services have a clear definition (e.g. system strength), they need to be provided efficiently in order to protect the long-term interest of electricity consumers, as defined in the National Electricity Objective.

1.6 In this context, it is becoming apparent that the current NEM market design for ESS, that has remained relatively stable[10] since it was introduced in the late 1990s, needs to evolve.

1.7 The COAG Energy Council has initiated a wide-ranging review programme to consider potential options for a long-term market framework design, to meet the National Electricity Objective. As part of this programme, ESB has been requested to undertake a preliminary development of potential fit for purpose frameworks, for the benefit of electricity consumers, including the provision of Essential System Services.[11]

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8 "*Power system security relates to: i) the technical parameters of the power system such as voltage and frequency; ii) the rate at which these parameters might change; and iii) the ability of the system to withstand faults. The power system is secure when technical parameters within defined limits.*" Source: AEMC, Security website (link). Accessed 18/06/2020.

9 "*A reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence.*" AEMC, Reliability Website (link). Accessed 18/06/2020.

10 We recognise that various modifications have taken place to introduce, modify and adapt the definition, procurement and scheduling of ESS and indeed this process is ongoing. However, the overall market design framework appears to have remained broadly unchanged.

11 COAG, Post 2025 Market Design - Scope and Forward Work Plan, 22 March 2019 (link).

Purpose and objectives of this report

1.8 ESB, in collaboration with the Australian Energy Market Operator ("**AEMO**"), the Australian Energy Regulator ("**AER**") and the Australian Energy Market Commission ("**AEMC**"), has been requested to advise on a long-term, fit for purpose market framework to support reliability and security, modifying the National Electricity Market as necessary, to meet the needs of future diverse sources of intermittent inverter-based generation and flexible resources including demand response, storage and distributed energy resource ("**DER**") participation.

1.9 The purpose of this report is to support ESB on one specific strand of the post-2025 market design, relating to the essential system services. In this strand, ESB is looking to develop a system security services workplan that maps current and future required reforms in order to maintain the NEM in a secure state (see footnote 8).

1.10 This report seeks to assist ESB by examining options for the provision of ESS in the NEM that would be in the long-term consumer interest, in the context of a growing penetration of IBR and VRE, often distribution-connected, alongside the progressive closure of the NEM's large-scale thermal synchronous generation fleet. Specifically, in this report, we:

- Describe the **drivers of the need** for current and future ESS, and examine the specific most relevant **characteristics** ('design parameters') of ESS that need to be considered in developing a new procurement framework;
- Propose **a framework to procure ESS** (i.e. ensure that adequate resources exist to provide the services, some of which may need to be constructed) and to **schedule ESS** (i.e. dispatch existing resources) that is fit for purpose in the context of long-term decarbonisation ambitions in the NEM; and
- Propose **options for a regulatory framework** that could support the procurement and scheduling of ESS.

Restrictions

1.11 This report has been prepared solely for the benefit of ESB and AEMC[12] for the purpose described in this introduction.

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12 Under the terms of the Engagement for services between AEMC and FTI Consulting, dated 23 April 2020.

1.12 FTI Consulting accepts no liability or duty of care to any person other than ESB and AEMC for the content of the report and disclaims all responsibility for the consequences of any person other than ESB or AEMC acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

Limitations to the scope of our work

1.13 This report contains information obtained or derived from a variety of sources. FTI Consulting has not sought to establish the reliability of those sources or verified the information provided.

1.14 No representation or warranty of any kind (whether express or implied) is given by FTI Consulting to any person (except to ESB and AEMC under the relevant terms of our engagement) as to the accuracy or completeness of this report.

1.15 This report is based on information available to FTI Consulting at the time of writing of the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

Structure of this report

1.16 This report has the following sections:

- Section 2 presents the background on Essential System Services, and the current arrangements for their provision in the NEM.
- Section 3 explains how the expected transition to a system dominated by non-synchronous and distributed generation drives a “case for change” for the current ESS procurement.
- Section 4 outlines the principles that seem most likely to represent good policy outcomes when assessing potential changes to the current ESS arrangements.
- Section 5 describes the key design parameters of how ESS may be procured differently in the future, and the different sub-variants that may be considered.
- Section 6 presents a conceptual framework for procuring and scheduling ESS, which provides a menu of options ranging from adjustments to the current NEM design through to the concept of “demand curves”.
- Section 7 applies the framework for procuring and scheduling to consider how different options could be applied to individual system services.
- Section 8 describes how the regulatory regime may need to adapt in order to implement a new ESS design.
- Section 9 proposes a roadmap for the potential implementation of the ESS reforms discussed within this report.

1.17 In addition, Appendix 1 and Appendix 2 discuss international examples of ESS procurement models and regulatory regimes, respectively, in further detail. A Glossary of key terms used in this report is attached at the end of this report.

2. Background to ESS

2.1 Electricity systems are highly complex systems made of a very large number of interlinked components such as generators, networks, storage and loads (or demand). The combined behaviour of all these components determines how the NEM power system performs as a whole. For the power system to operate securely it is necessary to achieve power system stability, defined as "*ability of the electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical or electrical disturbance, with system variables bounded so that practically the entire power system remains intact*".[13]

2.2 To provide the necessary system stability, the design of the NEM aims to mitigate any disturbances to the system balance, for example by preventing, arresting or recovering from system imbalances (or, in extreme cases, bringing a system back online following a black-out). A subset of these actions are sufficiently distinct and tangible, such that they can be identified as specific "services" that help meet the objective of keeping the system stable.

2.3 The primary way to achieve a balance of electricity supply and demand is **bulk energy**, i.e. the MWh of energy traded through a wholesale electricity market. In the NEM, this is done with 5-minute granularity. However, bulk energy alone is not sufficient, from an operational point of view, to maintain a stable, secure and resilient power system, as the system needs to be balanced over a much more granular timeframe (each second, or even less). Therefore, additional services are required to complement bulk energy in order to meet the needs of network users.

13 AEMO, Power system stability guidelines, 25 May 2012 (link), page 5. At a high level, the different aspects of system stability relate to the continuous supply-demand balancing of active power (frequency stability) and of reactive power (voltage stability), and to oscillatory, transient and control system stability.

2.4 In this report, we refer to the suite of specific services (provided alongside bulk energy) that help to keep the system stable and secure as ESS or ancillary services.[14] Historically, many of these services have been provided by large-scale synchronous generators, but the progressive retirement and displacement of these units from the operational timeframe has led to a falling provision of some of these services (we explore this further in Section 3 below). This poses a challenge to the NEM which, in line with most other power system around the world, has been developed around the implicit provision of ESS from synchronous resources.

2.5 This section examines the main categories of ESS that are currently used in the NEM.[15] We first present the different categories of ESS, and the underlying frameworks that are currently in place in the NEM for their provision (**Section A**). **Section B** discusses the interrelated nature of the system services, and what implications those interdependencies might have for the provision of ESS.

A. Current Essential System Services

2.6 In this section we describe the key features of the main seven categories of ESS, as they have been historically defined in the NEM. While we recognise that in the future these services may be re-specified (or indeed new services[16] may be defined), we consider this a helpful way of framing the salient features of the existing market design.

2.7 An overview of the seven categories of ESS is presented in Figure 2-1 below and described in detail in the following subsections. For each of the services, we first present its main characteristics, followed by a description of the current NEM arrangements for its provision.

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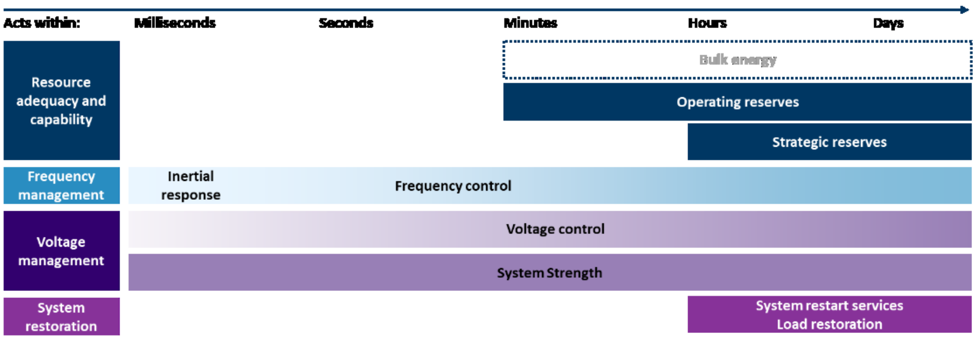
14 This definition includes both market ancillary services and non-market ancillary services.

15 Other jurisdictions may use a slightly different mapping of services, but the overall system needs, based on the prevailing technology, are broadly similar across the globe.

16 For example, the provision of inertia as an explicit system service only became apparent as levels of inertia in the NEM have fallen. Before then, sufficient inertia was assured by the dominance of synchronous generation on the system. It is possible to envisage that in the future other system needs may emerge as technology evolves, further changing the power system.

Figure 2-1: Overview of current categories of ESS in the NEM



Source: FTI analysis based on AEMO, Power system requirements, March 2018 (link), page 9.

Operating reserves

2.8 In a power system, operating reserves refer to dispatchable capacity in the market that can be called upon by the system operator or by market participants in response to unexpected changes in electricity demand or supply. This includes the ability of the system to meet peak demand and also to respond to changes in net demand (i.e. flexibility reserves). The key characteristics of operating reserves as a service are set out in Figure 2-2 below.

Figure 2-2: Operating reserves characteristics

Unit of measurement	**Megawatts, MW**				
Timing of need from real time	**Milliseconds**	**Seconds**	**Minutes**	**Hours**	**Days**
Spatial need	**Regional, with some locational flexibility** **Transmission constraints need to be considered**				

Source: FTI analysis, based on AEMO, Power System Requirements, March 2018 (link).

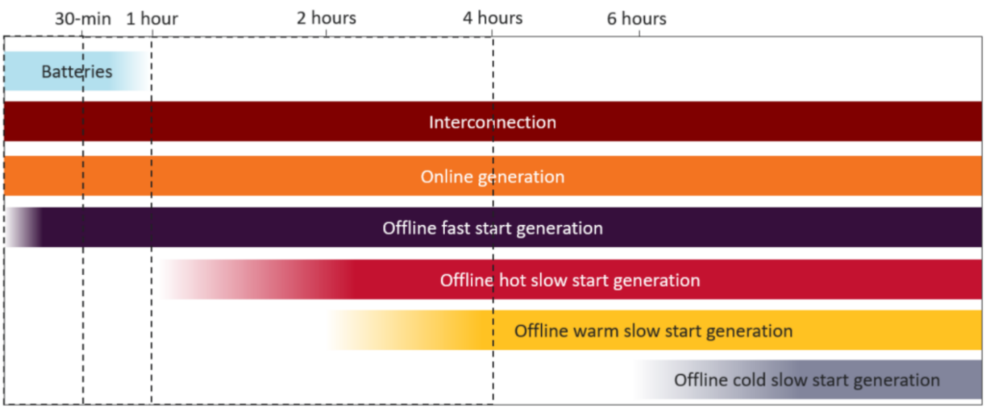
2.9 From an operational perspective, this service is needed to cover for situations where there may be insufficient capacity to meet demand during periods of unexpected increases in demand or reductions in supply, and to prevent involuntary load shedding. From a longer-term (investment) perspective, this service ensures that there is sufficient MW capacity available on the system to meet demand at all times.

2.10 Operating reserves are often categorised by their **response time**, for example those that can respond within 10 minutes or within 30 minutes, and by the **duration** over which the response can be sustained (e.g. minutes or hours). They can also be divided into whether they are online and "spinning" or whether they are offline and must start up before providing a response. Different resources have different technical characteristics, for example in terms of the speed and duration of response to meeting supply gap.

- Hydro, gas turbines and liquid fuel generators are generally considered to be the most flexible conventional generation types (for example, peaking gas plants can respond within several minutes) and they can typically provide response for extended periods of time.[17]
- Coal generators are typically slow-starting units. While they are able to adjust their output, within technical limits, when already online, they typically require several hours' notice to start up from cold.[18]
- For some technologies, such as batteries, the speed of response can be very fast, but the duration of the response may be limited as the resource is limited by the amount of charge.

2.11 Figure 2-3 illustrates the response time characteristics for a selection of resources.

Figure 2-3: Response time of various resources



Source: AEMO, Renewable Integration Study Stage 1 Appendix C: Managing variability and uncertainty, April 2020 (link)

17 AEMO, Renewable Integration Study Stage 1 Appendix C: Managing variability and uncertainty, April 2020 (link), page 46.

18 This indicates that, to some extent, operating reserve shortfalls may be a transitory issue, while the NEM moves away from slow-starting legacy coal-fired generation.

2.12 Historically, operating reserves have been provided by the unused capacity within synchronous generators (typically, generators that are already operating at some level of output and are ready to inject more power), hydro and demand response (resources able to reduce demand). In the future, storage assets, such as batteries, are likely to play a greater role in the provision of reserves (although their capacity is limited and requires charging).

2.13 Currently in the NEM, there is no centralised mechanism for the procurement of operating reserves. Rather, their provision is decentralised and a side consequence of the energy market decisions of individual suppliers, in anticipation of RT energy prices and the likelihood of being dispatched – consistent with the current NEM design as an energy only market.[19]

2.14 Within the NEM, operating reserves and reserve margins have been declining in recent years, as demonstrated by the increasing frequency with which Lack of Reserve ("**LOR**") notices have been declared in recent years (as discussed in Section 3 later in the report). This reflects a combination of two factors: lack of capacity to meet demand at all times, and lack of flexible capacity to meet unexpected changes in net load. This has prompted some parties to examine other options for the procurement of operating reserves in the NEM. For example, Infigen recently submitted a rule change request which proposes the introduction of a market for operating reserves. In this market, AEMO would procure reserves (either supply side or demand side) in RT, co-optimised with other energy markets.[20] The request is currently with AEMC, pending further review and consultation.

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19 Some other jurisdictions procure operating reserves in a centralised manner. The underlying market design question is whether markets and the commercial decisions of individual generators can be relied upon by policy makers to provide sufficient levels of operating reserves. This is explored in more detail in Section 5.

20 Infigen, Letter to AEMC Re: Operating Reserves and Fast Frequency Response Rule Change, 18 March 2020 (link).

2.15 In terms of near-term developments for operating reserves, in June 2020 AEMC made a rule to develop a demand response mechanism, such that load can form part of the in-market resources considered in the wholesale market.[21] Specifically, the rule introduces a new category of registered participant, a demand response service provider ("**DRSP**"). These providers would be able to bid demand response directly into the wholesale market as a substitute for generation and would be able to respond to LOR notices issued by reducing demand during periods of low reserves.

Strategic reserves

2.16 In a power system, strategic reserves refer to capacity that sits outside of the market but can be called upon by the system operator as "insurance" against unexpected changes in electricity demand or supply, and in the event that sufficient volumes of other types of services that are "within" the market (such as operating reserves) are unavailable. The key characteristics of strategic reserves as a service are set out in Figure 2-4 below.

Figure 2-4: Strategic reserves characteristics

Unit of measurement	Megawatts, MW				
Timing of need from real time	Milliseconds	Seconds	Minutes	Hours	Days
Spatial need	Regional, with some locational flexibility Transmission constraints need to be considered				

Source: FTI analysis, based on AEMO, Power System Requirements, March 2018 (link).

2.17 The difference between strategic reserves and operating reserves is whether the service is provided through a market or not, rather than the technical features – which are very similar:

- Strategic reserves (similarly to operating reserves) are needed to cover for situations where there may be insufficient capacity to meet demand during periods of unexpected increases in demand or reductions in supply, and to prevent involuntary load shedding.

21 AEMC, National Electricity Amendment (Wholesale Demand Response Mechanism) Rule 2020 - National Energy Retail Amendment (Wholesale Demand Response Mechanism) Rule 2020, 11 June 2020 (link).

- Strategic reserves can be categorised by their response times, and may also vary by duration over which the response can be sustained (as discussed in ¶2.10).
- Strategic reserves can be provided by the same types of resources as the operating reserves, which becomes relevant when considering future market design options (although typically in the NEM, strategic reserves are predominantly provided by demand response from large industrial loads).

2.18 Currently in the NEM, AEMO conducts reserve assessments up to seven days ahead of time through its short-term Projected Assessment of System Adequacy ("**PASA**").[22] If a shortfall is found, a LOR is declared. There are three categories of LOR, which vary by the severity of shortage. LOR1 is the least severe and allows market participants to respond by voluntarily committing more capacity to the market. LOR3 is the most severe and indicates that capacity reserves are at or below zero, resulting in load shedding.[23] A LOR2 or LOR3 notice provides a benchmark for AEMO to intervene in the market.[24]

2.19 AEMO also conducts a medium and a long-term PASA. The medium-term PASA is conducted monthly and covers the next two years,[25] while the long-term PASA is conducted annually as part of the Electricity Statement of Opportunities ("**ESOO**") and covers the next 10 years.[26] The wider ESOO provides the market with a 10 year projection to assist with long-term planning, and contains a reliability assessment against AEMO's Retailer Reliability Obligations and the reliability standard defined in the National Electricity Rules.[27]

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22 AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 32.

23 AEMO, Reserve level declaration guidelines, 12 December 2018 (link), page 10.

24 AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 32.

25 AEMO, Medium term PASA website (link). Accessed 25/06/2020.

26 AEMO, PASA website (link). Accessed 25/06/2020.

27 AEMO, NEM Electricity Statement of Opportunities website (link). Accessed 25/06/2020.

2.20 AEMO commits additional strategic reserve capacity through a specific mechanism, called the Reliability and Emergency Reserve Trader ("**RERT**"). There are three types of RERT, covering different time-scales:

- The **long-notice RERT**, where the RERT is procured between 12 months and 10 weeks from the projected shortfall period. These contracts are procured through an invitation-to-tender process.
- The **medium-notice RERT**, where the RERT is procured between 10 weeks and seven days from the projected shortfall period. These contracts can be procured from the RERT panel,[28] with prices negotiated separately each time.
- The **short-notice RERT**, where the RERT is procured between seven days and three hours from the projected shortfall period. These contracts can be procured from the RERT panel, using pre-agreed prices.

2.21 Market participants may also make a commercial decision to maintain reserves within their portfolios to ensure they can meet their contractual obligations.

2.22 In terms of near-term developments expected for strategic reserves, ESB is developing a strategic reserve mechanism (the Interim Reliability Measure), which tightens the Unserved Energy threshold to 0.0006% (per calendar year). This will require AEMO to procure additional strategic reserves, with contract terms of up to three years, until 2024/25 summer.

Frequency control

2.23 Frequency control refers to the process of continually balancing electricity supply and demand to ensure system frequency remains within a defined band (close to 50 Hz). Significant deviations from this band can lead to equipment and infrastructure damage, plant trips and load shedding. The key characteristics of frequency control as a service are set out in Figure 2-5 below.

28 The RERT panel is comprised of entities that have pre-qualified to provide strategic reserves.

Figure 2-5: Frequency control characteristics

Unit of measurement	Megawatts, MW
Timing of need from real time	**Milliseconds Seconds Minutes** (highlighted) Hours Days
Spatial need	Generally location-independent, but requirements can become regional in case of separation events

Source: FTI analysis, based on AEMO, Power System Requirements, March 2018 (link).

2.24 A frequency control service is a service that acts to rebalance or stabilise the power system frequency by varying the active power provided into or taken from the power system in response to frequency variations.

2.25 Frequency control can be provided on a switched-on/off basis (when a response is triggered in response to a set variation, i.e. a threshold) or a proportionate basis (i.e. continuously in proportion to any deviation in frequency from 50Hz). Typically, there is a trade-off between response time and duration of response.

2.26 Generally, the service is location independent (i.e. resources located anywhere in the network can contribute to frequency control), as some technological limits, such as transmission constraints, can be temporarily overridden (to a certain extent).[29] However, the requirements for frequency response capability may in some cases become regional – for example in the case where there is a risk of a separation event (i.e. a situation where one part of the NEM system is "islanded" from the rest of the system), as in such cases it is physically not possible to rely on frequency response capabilities from a disconnected region.

[29] For instance, the NEM design allows for frequency response services to be transferred across interconnectors, and this is reflected in the security-constrained dispatch and the locational purchases of frequency control services.

2.27 Frequency response can be provided by both synchronous and non-synchronous generation, demand response, DER, batteries, and other storage assets, although each have their own specific advantages and disadvantages:

- Synchronous, dispatchable generation (assuming part-loaded): Can provide frequency response for long periods of time, but the response time may sometimes be relatively slow.
- Non-synchronous, VRE: If VRE resources maintain a degree of headroom, they can provide very fast, dispatchable frequency control raise services, and there are already examples of this happening in the NEM (e.g. the Hornsdale 2 windfarm). VRE resources can also provide frequency control lower services (even without headroom). The variable nature of these resources may limit their effectiveness as a frequency response mechanism, as capacity is less "firm" and predictable, although accurate forecasting may mitigate this to some extent.
- Demand response: Load typically provides a discrete response to contingency events and can respond very quickly, but has tended to be limited in its ability to provide a regulating (i.e. continuous) response.[30] Additionally, it is generally only suited to provide raise frequency control (i.e. through reducing demand), rather than lower frequency control (i.e. increasing demand). In the US, demand response has been providing frequency response for a number of years, including from aluminium potlines, sewage treatment plants and aggregations of air conditioning. Likewise, in the NEM, demand response has been providing an increasing share of fast raise frequency control in recent years.[31]
- Batteries/storage: These assets often have a fast response time and have been recently shown to perform well, but they also have limited capacity before they become depleted (and need to be charged up). Distribution across the NEM may also be a factor, as substantial battery capacity in one region may result in large and rapid swings in the amount of MW transferred across regions during battery discharge.

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30 *"AEMO is keen to collaborate with [Virtual Power Plant] Demonstrations participants to develop a test to explore whether [Virtual Power Plants] would be capable of delivering a frequency regulation service."* Source: AEMO, Virtual Power Plant Demonstration Knowledge Sharing Report 1, March 2020 (link), page 15.

31 AEMO, Renewable Integration Study Stage 1 Appendix B: Frequency control, March 2020 (link), pages 32 & 33.

2.28 This indicates that, currently, there is no single technology that is best able to meet all the NEM frequency response needs, and the ability to draw upon a mix of technologies is likely to be required.

2.29 Currently in the NEM, frequency control is provided via both mandatory and voluntary market mechanisms. All scheduled and semi-scheduled[32] generators are obligated to provide primary frequency response. Additionally, eight separate FCAS markets exist.[33] There are two markets for regulation reserves (which are centrally controlled and respond to small deviations in frequency within a 5 minute dispatch interval) and six for contingency reserves (which respond to arrest, stabilise and recover frequency following a major change in frequency). Market participants voluntarily submit offers into these eight markets. Most recently, Infigen has proposed the introduction of two additional FCAS markets for fast frequency response, and this is currently being examined by AEMC.[34]

2.30 FCAS offers are co-optimised with energy and assessed by the National Electricity Market Dispatch Engine ("**NEMDE**") every 5 minutes. The NEMDE identifies the required levels of FCAS, which are then procured by AEMO from the spot markets at the prevailing market prices.

2.31 In addition, a Mandatory Primary Frequency Response ("**MPFR**") requirement has recently been introduced by AEMC that requires scheduled and semi-scheduled generators to provide primary frequency response if they have the capability.[35]

32 "*Semi scheduled generators are intermittent renewable energy generators such as grid scale wind and solar farms*". These generators face less stringent dispatch obligations in comparison to traditional scheduled generators. Source: AER, Issues Paper – Semi scheduled generator rule change(s), June 2020 (link).

33 AEMO, Guide to Ancillary Services in the National Electricity Market, April 2015 (link), page 6.

34 Infigen, Letter to AEMC Re: Operating Reserves and Fast Frequency Response Rule Change, 18 March 2020 (link).

35 This change has been made in response to a degradation of frequency control performance. For more details see paragraph 3.24.

2.32 A number of important differences exist between FCAS and MPFR, including that:

- FCAS providers are compensated for the service, while MPFR providers are currently not compensated (although a plan is underway to develop future arrangements to appropriately incentivise and reward frequency control in the NEM);[36]
- FCAS providers must maintain a degree of headroom/footroom to respond should a contingency occur, whereas MPFR providers have no such obligation; and
- FCAS providers are subject to a much higher level of compliance testing than MPFR providers.

2.33 The NEM also has an Emergency Frequency Control Scheme ("**EFCS**") for use during major frequency events (when frequency deviates from the normal operating frequency band).

System inertia

2.34 System inertia (referred to in this report as "inertia") is the store of kinetic energy that is "*provided by the aggregate rotating mass of all synchronous machines and motors that are directly coupled to the grid"*.[37] When there is a change in frequency, energy is transferred between the grid and these machines, helping to arrest fluctuations in frequency and stabilise the system.

2.35 Inertia increases the resilience of the power system to disturbances, as it reduces the rate at which frequency changes following a disturbance (referred to as the Rate of Change of Frequency, "**RoCoF**"). Consequently, a shortfall of inertia makes the power system less stable, i.e. more prone to a rapid change of frequency following a disturbance. The key characteristics of inertia as a service are set out in Figure 2-6 below.

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36 AEMC, Primary Frequency Response Rule Changes Information Sheet, 19 September 2019 (link).

37 AEMO, Renewable Integration Study Stage 1 Appendix B: Frequency control, March 2020 (link), page 13.

Figure 2-6: Inertia characteristics

Unit of measurement	Megawatt-second, MWs
Timing of need from real time	**Milliseconds Seconds** Minutes Hours Days
Spatial need	Generally system-wide, but location-specific elements e.g. min levels for regions at risk of islanding Also has other locational attributes, in respect of transient and oscillatory stability
Structure of service	Inertia is a binary service, in the sense that a synchronous machine is either online and operating in synchronisation with the power system, or it is not

Source: FTI analysis, based on AEMO, Power System Requirements, March 2018 (link). Note: Although described above as required within "milliseconds to seconds", inertia is in practice required to be provided continuously, i.e. at all times.

2.36 Inertia can currently be provided by:

- synchronous generation (while providing energy);
- synchronous generators operating in synchronous condenser mode (without injecting active energy);
- high inertia synchronous condensers (with flywheels); and
- interconnection facilitating the provision of inertial response from other areas.

2.37 In the future, new forms of "synthetic" or "virtual" inertia may emerge. Whilst these are being trialled, their technological capabilities are as yet unproven and may not be fully consistent with the traditional definition of inertia (although that is not to say the system cannot, or should not, accommodate these innovative technologies in the future).

2.38 Generally, inertia is location independent. However, location-specific requirements may be necessary in certain cases, such as for areas that are at risk of islanding. Inertia is also important to consider when determining the transient and oscillatory stability of the power system (see footnote 13).

2.39 Currently in the NEM, inertia is mainly provided as a "by-product" of bulk energy and is only provided by synchronous resources. In terms of its procurement:

- AEMO does not currently procure an explicit inertia "product" but can take specific actions to mitigate anticipated shortfalls in inertia (e.g. through directions).
- Transmission Network System Providers ("**TNSPs**") procure synchronous inertia (as discussed in the paragraph below) in order to support a secure operation of the system.

2.40 In response to falling inertia levels, AEMO is now required to calculate minimum inertia requirements for each inertia sub-network (areas that are at risk of "islanding") and identify and forecast any shortfalls arising in the next 5 years.[38] If a likely or actual shortfall is declared, the relevant TNSP has an obligation to mitigate the shortfall through contracting or investing in network assets. For example:

- ElectraNet, the SA TNSP, is installing four high inertia synchronous condensers (with flywheels) to meet the identified system strength and inertia gaps. This has been approved by AER and the synchronous condensers are expected to provide 4,400 MWs of inertia once installed by the end of 2020.[39]
- TasNetworks, the Tasmanian TNSP, has contracted for the provision of inertia from a provider offering synchronous condenser capabilities.[40] A similar arrangement is pursued in Queensland, under current National Electricity Rules ("**NER**") arrangements.

2.41 A mechanism for maintaining a minimum limit on inertia for mainland NEM under system intact operation has also been explored by AEMO in a recent Renewable Integration Study, but this is yet to be explored further.[41]

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38 AEMO, Inertia Requirement and Shortfalls, 29 June 2018 (link), page 13.

39 ElectraNet, Addressing the System Strength Gap in SA: Economic Evaluation Report, 18 February 2019 (link), page 15.

40 AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 29.

41 AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 48.

System Strength

2.42 System strength is a multifaceted concept that can be defined as "*the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance*".[42] In other words, it reflects the sensitivity and robustness of the local power system, with respect to properties other than inertia.[43]

2.43 In the NEM, it is used as an umbrella term to cover a number of interrelated variables, comprising of both active elements, such as the provision of synchronous generation, and passive elements, such as more effective tuning of individual inverter control room settings and co-ordination of control settings across multiple IBR generators.

2.44 The key characteristics of system strength as a service are set out in Figure 2-7 below.

Figure 2-7: System strength characteristics

Unit of measurement	**No unit available, although fault levels and short circuit ratio can provide an indication – otherwise determined through power system studies**
Timing of need from real time	**Milliseconds Seconds Minutes Hours Days**
Spatial need	**Local (specific need dependant on local network characteristics)**

Source: FTI analysis, based on AEMO, Power System Requirements, March 2018 (link).

[42] AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 50.

[43] AEMO, Transfer Limit Advice – System Strength, February 2020 (link).

2.45 While system strength does not have a single measurable unit, fault current can be used as a proxy to represent the effects of system strength.[44] The system strength at a given location is proportional to the fault level at that location - the higher the fault current, the "stronger" the system is said to be. However, this unit of measurement can only be considered to be one of several potential different ways in which system strength can be approximated.[45] To more accurately determine the level of system strength, a detailed power system study is required, which requires complex models that AEMO and network operators have access to. Typically, these models are used to underpin longer-term planning studies, but currently cannot be used to support scheduling decisions in RT.

2.46 System strength is also a location specific service, meaning that providers of the service must be distributed across the NEM to ensure sufficient coverage (particularly given the relatively long and less "meshed" nature of the NEM in comparison to the networks in Europe or in the US).

2.47 Low system strength can lead to technical problems,[46] which in turn can damage equipment and infrastructure. Low system strength may also inhibit the system from recovering from faults and disturbances quickly.

2.48 A certain level of system strength is required for most currently used "grid following" IBR technologies to connect reliably to the power system (although inverter technology that supports connection at lower levels of system strength is being developed, as discussed below).

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44 Fault current is the electrical current (in Amps) that flows during a fault and is also referred to as the short circuit current. Source: AEMO, System Strength Explained, March 2020 (link), page 4.

45 Another proxy of system strength is the short circuit level, which is a ratio of the inverter size to the fault level at the point of connection. This measure is used as a screen in impact assessments. Source: AEMO, System Strength in the NEM Explained, March 2020 (link), page 5.

46 Technical issues associated with low system strength include: "*wider area undamped voltage and power oscillations, generator fault ride-though degradation, mal-operation or failure of protection equipment to operate, prolonged voltage recovery*" Source: AEMO, System Strength Explained, March 2020 (link), pages 6 and 7.

2.49 Historically, system strength has been provided by synchronous generation and synchronous condensers, and this is expected to continue being the case going forward. However, the benefit of a given amount of synchronous generation (or output from synchronous condensers) for total system strength also depends on:

- The **network protection systems** in place: more effective and correctly set up protection systems help maintain overall system stability and security, and thus increase the benefit that the operation of synchronous machines provides to the network;
- The **network characteristics**: a stronger network (with lower impedance) enables the system to "transport" the provision of a particular synchronous machine to a wider area and thus increase the benefits provided by a particular resource by enlarging its geographical footprint (although this does not displace the need for a synchronous machine itself); and
- The **power electronics (inverters)** characteristics: more advanced inverters (e.g. on some modern solar and wind generators) enable those resources to withstand greater system disturbances, and thus enable a given volume of output from synchronous machines to support a higher volume of IBR. In the future, very advanced inverters (e.g. "virtual synchronous machines") might also contribute to system strength, by actively supporting stable voltage waveforms rather than simply being able to withstand disturbances, but this is as yet unproven.

2.50 To maintain a desired level of system strength, it is therefore important to consider not only the provision of the service by synchronous machines, but also the wider physical network elements described above. AEMC is currently exploring these other elements of maintaining system strength (as well as inertia) through its System Strength Frameworks investigation.[47] We understand that there may be a future desire to be able to draw system strength from more sources than the existing power plants, so as to reduce opportunities for the incumbents to exercise market power.

[47] AEMC, Investigation Into System Strength Frameworks in the NEM Discussion Paper, 26 March 2020 (link).

2.51 Currently in the NEM, there is no defined system strength "product" as, historically, sufficient quantities have been provided as a by-product of synchronous generation. AEMO ensures that at any given time, a sufficient number of synchronous generators remain online to provide the required levels of system strength, but when this is not the case AEMO can take out-of-market actions (e.g. directions) to bring such resources online, and may also curtail inverter-based generation. However, the need for system strength in the NEM is currently expressed in a relatively simplistic way (see Box 2-1 below).

Box 2-1: System strength needs

AEMO has recently summarised the system strength needs for South Australia and Victoria by listing the combinations of synchronous generation units that "*would provide sufficient system strength to withstand a credible fault and loss of a synchronous unit*".[48] These combinations, while not exhaustive, provide a range of options for the system strength to be maintained and are presented in a series of tables, referred to in this report as "TLA tables".

Importantly, these combinations are available for different levels of non-synchronous generation levels (typically with more synchronous units being required to support a higher level of non-synchronous generation), and in some cases for different levels of transfers into a region. An example of these combinations is shown in Figure 2-8 below.

Figure 2-8: Example of a TLA table for system strength in South Australia

Combination	Non-sync generation level	Torrens Island A				Torrens Island B				Pelican Point			Osborne		Quarantine or Dry Creek*
		Ax	Ax	Ax	Ax	Bx	Bx	Bx	Bx	GTx	GTx	ST18	GT	ST	
LOW_2	≤ 1,300 MW					■	■			■		■			
LOW_3	≤ 1,700 MW					■	■						■	■	■
LOW_4	≤ 1,450 MW									■		■	■	■	■
LOW_5A	≤ 1,700 MW	■	■	■		■	■								
LOW_5B	≤ 1,700 MW	■	■			■	■	■							
LOW_6	≤ 1,700 MW					■				■	■	■			
LOW_7	≤ 1,700 MW	■	■							■		■			■
LOW_8	≤ 1,600 MW	■				■				■		■	■	■	
LOW_9	≤ 1,650 MW	■	■	■		■							■	■	
LOW_10	≤ 1,750 MW	■	■			■	■						■	■	
LOW_11	≤ 1,700 MW	■								■	■	■			
LOW_13	≤ 1,700 MW	■				■	■	■					■	■	
LOW_14	≤ 1,300 MW	■	■			■				■		■			

Source: AEMO, Transfer Limit Advice – System Strength, February 2020 (link), page 8.

48 AEMO, Transfer Limit Advice – System Strength, February 2020 (link), ("**TLA Paper**"), page 8.

These combinations of units provide a simplified picture of the need for system strength in the NEM:

- They do not provide a clear trade-off between the different combinations used (e.g. whether option LOW_6 or LOW_7 is cheaper), which reduces the transparency of the selection of unit combinations to provide system strength.
- They focus on the minimum technical requirement to maintain system security (and do not consider that some combinations of units may increase the system's ability to withstand multiple contingencies and/or facilitate higher deployment of IBR[49]);
- They do not cover all combinations of units that may be feasible and provide an adequate (or superior) level of system strength;
- They may not provide sufficient clarity to future prospective investors on where on the network additional investment in system strength may be required (and how it would be remunerated); and

The implications of the current approach to assessing system strength and a potential way forward to improving this design is discussed in Section 7D.2.

2.52 Reductions in synchronous generation over recent years (both through closures and withdrawal from dispatch), and its displacement by IBR technologies, such as wind and solar, have led to shortfalls in certain regions, such as South Australia and North Queensland.

2.53 Similarly to inertia (as discussed in the previous section), in response to falling levels of system strength, AEMO is now required to determine the minimum required level of system strength and fault level at defined "fault level nodes" and identify any shortfalls.[50] If a likely or actual shortfall is declared, the relevant TNSP has an obligation to mitigate the shortfall through:

- contracting the provision of the service from a third party; and/or
- investing in network assets (e.g. synchronous condensers) that can provide the service.

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49 This is only the case for some regions (e.g. South Australia and North Queensland). In other regions, the minimum synchronous generation currently does not place a constraint in VRE output, and this issue therefore has not yet arisen.

50 AEMO, System Strength Requirements Methodology and System Strength Requirements and Fault Level Shortfalls, 1 July 2018 (link).

2.54 The framework, which was established in 2017,[51] also requires that TNSPs ensure the connections of new generators do not compromise the existing system, i.e. that they "do no harm" to system strength, and that any adverse impacts on the stable operation of the power system are remedied.[52]

2.55 Several evolutions of the framework are currently being considered:

- AEMC has initiated a review to investigate the application of the current system strength frameworks and to identify potential improvements (e.g. passive/active obligation models, centralised/decentralised models, "do no harm" frameworks);[53]
- A rule change proposal has been submitted by HydroTas to integrate synchronous services into dispatch, such that synchronous services would be co-optimised with energy and FCAS;[54] and
- A rule change request has been submitted by TransGrid to abolish the "do no harm" mechanism and replace it with a centrally co-ordinated, network led approach to providing system strength.[55]

Voltage control/reactive power

2.56 Voltage control is the process of maintaining system voltage within acceptable limits through the absorption and injection of reactive power, and to enable recovery following a disturbance. Significant deviations from standard voltages can lead to equipment and infrastructure damage, plant trips and may result in load shedding.

2.57 The key characteristics of voltage control as a service are set out in Figure 2-9 below.

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51 AEMC, National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10, 19 September 2017 (link).

52 AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 51.

53 AEMC, Investigation Into System Strength Frameworks in the NEM Discussion Paper, 26 March 2020 (link).

54 Hydro Tasmania, Synchronous Services Markets Rule Change Proposal, 19 November 2019 (link).

55 TransGrid, Rule change proposal on a new system strength framework for the NEM, 27 April 2020 (link).

Figure 2-9: Voltage control characteristics

Unit of measurement	Mega volt amps, MVar
Timing of need from real time	Milliseconds Seconds Minutes Hours Days
Spatial need	Location-specific, which is a key concern, due to potential local market power

Source: FTI analysis, based on AEMO, Power System Requirements, March 2018 (link).

2.58 There are various types of voltage control, ranging from slow response voltage control, which is required continuously through to fast response voltage control, which is more "discrete" and required in response to system disturbances. Voltage control can also be categorised by whether it is static (e.g. injection/withdrawal of reactive power triggered in response to certain conditions) or dynamic (e.g. where a provider is required to have a reserve of reactive power that can be provided on a continuous basis).

2.59 Historically, voltage control has been provided actively by synchronous generation and passively through generator performance standards.

- Active provision of voltage control typically involves the injection or withdrawal of reactive power as a result of deliberate actions by the operators of static VAR compensators, static synchronous compensators and some inverter-based resources, such as solar, which can also provide voltage control services.
- Passive provision of voltage control / reactive power is not a "service" *per se*, but is driven by the technical standards agreed upon within generator performance standards. Examples include mandating the ability to provide reactive power if it is shown to be necessary for system security, and the ability to withstand disturbances to reduce the risk of cascading failures.

2.60 Reactive power is also generated and absorbed by network and demand equipment – when transmission demand is lower, electricity networks tend to generate reactive power, increasing voltage (which in turn must be managed by injecting or withdrawing reactive power), and vice versa.[56]

[56] NGESO (2018) System Operability Report - Frequency and Voltage assessment, June 2018 (link), page 2.

2.61 Like system strength, voltage control is a location-specific service – reactive power does not "travel" far.

2.62 Currently in the NEM, the responsibility for voltage control is split between AEMO, network system providers ("**NSP**") and generators. AEMO maintains voltage levels across the transmission network within appropriate limits by coordinating available reactive power resources in the network and from generators.

2.63 If the coordination of reactive power does not maintain voltages within the technical limits, AEMO can take additional steps including network reconfiguration, contracts with NSPs and generators (e.g. through the Network Support and Control Ancillary Services ("**NSCAS**") framework[57]), and load shedding.

2.64 The responsibility for planning, designing, and operating their networks to manage voltage lies with the NSPs. The associated costs (e.g. for reactive power support) are recovered through network charges. Networks also encourage power factor correction in charges for customers and connection requirements (including the installation of capacity banks).

2.65 Generators may also be responsible for providing voltage support. This is determined during the generator's application process and set out in the generator performance standards.

System recovery

2.66 System recovery is the process of restoring the power system to a safe and stable operating state following a black-out event.[58] At all times, contingency arrangements must be in place to ensure that the system can be restored quickly and efficiently, thus minimising the impact of the black-out.

2.67 The key characteristics of system restoration as a service are set out in Figure 2-10 below.

57 In the NEM, TNSPs have the primary responsibility for procuring NSCAS. Source: AEMO. NSCAS procedures and guidelines website (link). Accessed 26.06.2020.

58 AEMO, Power System Requirements, March 2019 (link), page 19.

Figure 2-10: System recovery characteristics

Timing of need from real time	Milliseconds	Seconds	Minutes	Hours	Days
Spatial need	Partly location-specific, to allow system re-energisation from multiple locations				

Source: FTI analysis, based on AEMO, Power System Requirements, March 2018 (link).

2.68 Recovery services are typically provided by generators that are able to start-up without an external electricity supply. This initial generator can then go on to energise sections of the system until a stable "power island" is created. The island is gradually expanded to further generators, until the eventually it is re-synchronised with the rest of the power system.[59]

2.69 Currently in the NEM, system restart ancillary services ("**SRAS**") are procured by AEMO in each region via a competitive tender process, in which bidders are assessed on factors such as strategic location, transmission reliability and fuel diversity. The procured SRAS must meet certain system restart standards set out by AEMC's Reliability Panel.[60]

2.70 AEMC has recently completed a rule change request relating to the procurement, testing and deployment of SRAS. Specifically, the rule change:[61]

- Expanded definitions relating to SRAS to allow AEMO to procure a wider range of technologies, such as batteries;
- Clarified that long-term costs are to be considered through the procurement process;
- Updated the testing framework for SRAS to incorporate the physical testing of system restart paths; and
- Introduced a system restoration support service which assists to stabilise the power system during re-energisation.

59 AEMO, Power System Requirements, March 2019 (link), page 19.

60 AEMO, Power System Requirements, March 2019 (link), page 19.

61 AEMC, National Electricity Amendment (System Restart Services, Standards and Testing) Rule 2020, 2 April 2020 (link).

B. Interrelationships among ESS

2.71 For ease of exposition, the previous section presented each category of ESS as an independent service. However, in practice, there are multiple interdependencies among ESS, as well as between ESS, bulk energy and wider market design features such as Resource Adequacy Mechanisms.[62]

2.72 The main interrelationships among ESS and other services include:

- **Degree of substitutability.** The provision of one service may simultaneously reduce the need for another service where the services are (at least partially) substitutable. For example, the provision of inertia increases the power system's resilience to any frequency disturbance (and hence lower RoCoF), such that the need for frequency control services may be reduced.
- **Shared cost base.** A given resource may be able to provide multiple services simultaneously, such that there is a shared cost base that may need to be taken into account when considering the provision of different services. For example, synchronous generation, while actively injecting energy, will also simultaneously provide inertia and system strength. However, provision of other services may be associated with specific costs (for example, the provision of additional strategic reserves that require an upfront investment).
- **Resource adequacy.** The provision of certain services (notably reserves) may contribute not only to system security (i.e. ensuring the system remains within technical limits) but also to reliability (the ability of bulk energy supply to meet demand).[63] The first issue, i.e. system security, is the primary focus of this ESS report, while the second issue, i.e. reliability, is explored in depth by ESB separately, as part of the wider post-2025 framework. Going forward, the interaction between the provision of ESS and Resource Adequacy Mechanisms should be considered as part of the post-2025 market design.

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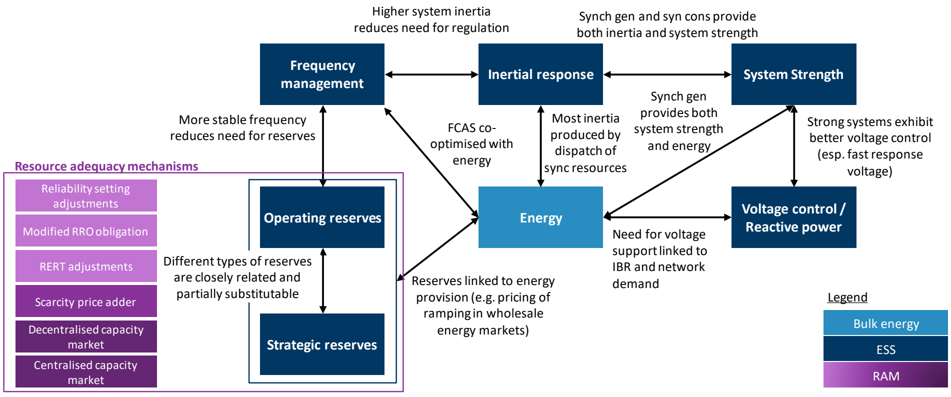
62 Resource adequacy mechanisms ("**RAMs**") are mechanisms to complement energy markets to improve the delivery of resource adequacy. RAMs support resource adequacy by providing resources with additional revenues and/or risk mitigating opportunities to increase the propensity to invest and be available when required.

63 AEMO states that "*'Reliable' means that the capacity to produce and transport electricity will be sufficient to meet the demand for electricity*." This is a separate concept to security, which considers the ability of the system to operate within technical limits, even following a major disturbance. Source: AEMO, System operations website (link). Accessed 26/05/2020.

2.73 The main interrelationships among ESS, energy and resource adequacy mechanisms are summarised in Figure 2-11 below and described in the following paragraphs.

Figure 2-11: Interrelationships between ESS, energy and resource adequacy mechanisms



Source: FTI analysis

Operating and strategic reserves

2.74 As discussed in ¶2.17, operating and strategic reserves are very similar in terms of technical features and providers of service – differing only by whether they provided through a market or not. This results in the two being partially substitutable - the procurement of one form of reserve can reduce the requirement for the other.

2.75 The provision of reserves is also closely linked to reliability and resource adequacy, which we explore in a separate Resource Adequacy Mechanism report.[64]

64 FTI, Resource Adequacy Mechanisms in the National Electricity Market. A Report for the Energy Security Board, 2020.

Reserves and bulk energy

2.76 Operating and strategic reserves are used to ensure that at any given moment, there is sufficient generation capacity to meet the demand for bulk energy. The supply and demand of bulk energy, both in terms of quantum and variability, is therefore closely related to reserve requirements. For example, a power system where the majority of energy is provided via thermal generation, which generally has a highly predictable and controllable generation profile, is likely to have lower reserve requirements than a power system which relies on more variable resources, such as wind and solar generation.

2.77 A further relationship between bulk energy and operating reserves exists in the NEM: as there is no explicit operating reserve market, the provision of operating reserves is remunerated through RT bulk energy prices, closely linking the two services.

Operating reserves and frequency control

2.78 At a conceptual level, operating reserves and frequency response offer closely related services in the sense that both help to ensure that energy supply equals energy demand at all times, thereby keeping the system within technical operating ranges. When a demand/supply imbalance occurs, this manifests itself in frequency deviation, which can be arrested through frequency control (FCAS regulation product), and ultimately stabilised through FCAS contingency and/or operating reserve. In both cases this is achieved through providers varying their levels of generation output (or electricity demand, in the case of demand response providers) to balance the system. The two services vary by the timescales over which they operate, with frequency response operating on a timescale of seconds (for FCAS regulation) or seconds to minutes (for FCAS contingency), while operating reserves tend to operate on a timescale of minutes to hours.

2.79 The interlinkages between the two services and the partial overlap between the timescales on which they operate is particularly relevant for operating reserves and contingency FCAS, which, as we discuss in ¶2.29, operate on longer timeframes and via a less automated system than regulation services. Greater procurement of contingency FCAS can help reduce the magnitude of reserves required to return the system to normal operating conditions following a contingency event, and vice versa.

2.80 Additionally, the providers of frequency control and reserve services are likely to be similar. Historically, synchronous thermal generation has provided the majority of reserves and frequency control, with newer technologies, such batteries and wind and solar generation, also now able to provide both services.

2.81 The interrelation of these services is demonstrated by the decision of some SOs, including the New York Independent System Operator ("**NYISO**") and the Midcontinent Independent System Operator ("**MISO**"), to co-optimise both frequency control and reserve services with bulk energy.

Frequency control and bulk energy

2.82 Frequency control services aim to ensure that frequency remains with a defined range by balancing energy supply and demand and are therefore closely related to the provision and variability of bulk energy. This interrelationship is already recognised in the NEM through the co-optimisation of FCAS with the dispatch of bulk energy.

Frequency control and inertia

2.83 In ¶2.35, we set out how inertia reduces the RoCoF within the power system following a disturbance. Decreasing inertia therefore increases the quantum of fast response frequency control products required to arrest the greater RoCoF and ensure that system frequency remains within technical operating limits. Conversely, faster frequency control enables the power system to operate securely at lower levels of inertia.[65] In GB, National Grid Electricity System Operator ("**NGESO**") has recently announced the introduction of a new rapid response frequency control product, stating that "*rapid management of frequency on a near RT basis is becoming increasingly important as the ESO operates a system with […] less inertia*".[66]

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65 "*Faster frequency response allows the power system to operate at lower levels of synchronous inertia, however no large power system operates today without synchronous inertia. Replacing synchronous inertia with fast acting control action may result in a system with very different system dynamics*". AEMO Renewable Integration Study Stage 1 Appendix B: Frequency control, March 2020 (link), page 31.

66 NGESO, New fast frequency product to boost National Grid ESO's response capability announcement, 2 December (link). Accessed 27/05/2020.

Inertia, system strength and bulk energy

2.84 Historically, provision of bulk energy has been closely related to both system strength and inertia, as both services have been traditionally provided by synchronous generation while simultaneously injecting energy to the grid. Inertia and system strength were therefore historically abundant, as the vast majority of bulk energy generation also produced inertia and system strength as a by-product. It is also common for inertia and system strength to be jointly provided (or to suffer from simultaneous shortfalls).[67]

2.85 However, increasing levels of IBR generation (which currently produce no inertia and do not contribute to system strength) and the retirement (and/or displacement from operational timeframes) of thermal synchronous generation in recent years has led to a weakening of the relationship between bulk energy and both inertia and system strength. There are now also technologies that can provide inertia and/or system strength without injecting energy to the system (such as synchronous condensers, or generators operating in a synchronous condenser mode). Nevertheless, despite the weakening relationship among them, inertia, system strength and bulk energy remain closely interrelated.

System strength and voltage control

2.86 As described in ¶2.42, system strength represents the ability of the system to control the voltage waveform. Voltage control services are therefore linked to system strength, with fast response voltage control in particular contributing to the strength of a power system. System strength and voltage control can also be provided by some of the same resources, such as synchronous generators and synchronous condensers.

2.87 Both services are also typically highly locational in the sense that shortfalls typically arise over geographical footprints that are considerably smaller than the five NEM regions.

Voltage control and bulk energy

2.88 A key driver of the need for voltage control services and the injection and absorption of reactive power is the volume of energy demand on the power system. As explained in ¶2.60, low levels of bulk energy transmission increase the voltage in the power system, and vice versa, thus closely linking the two services. Additionally, providers of bulk energy are also typically able to provide voltage control services, including both thermal synchronous generation and IBR generation.

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67 AEMO, System Strength Explained, March 2020 (link), page 6.

3. Future needs for ESS

3.1 The assessment of the procurement framework for Essential System Services takes place in the context of a long-term transition of the NEM power mix away from conventional synchronous thermal generation, towards a mix dominated by VRE and IBR, both at utility scale (transmission-connected) and behind-the-meter (distribution-connected).

3.2 In this section, we first set out the recent trends and the forecast of future changes to the generation mix (**Section A**).

3.3 The impact of these trends on power system performance is described in **Section B**. We set out how the increase in IBR penetration and the associated fall in synchronous generation have manifested themselves as increasingly uncertain net loads, falling system inertia, deteriorating frequency performance and weakening system strength. We then explain that future trends are expected to exacerbate these system challenges.

3.4 Finally, we consider in **Section C** whether these emerging power system challenges are likely to be adequately mitigated through the existing ESS framework design (described in Section 2 above). Where this is unlikely, we identify the case for considering changes to the current ESS framework, in order to deliver a secure power system.

A. Recent Trends and Expected Future Changes

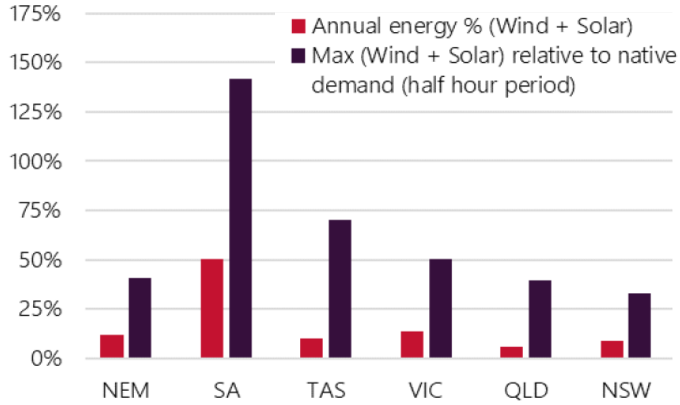
3.5 In common with many other parts of the world, the NEM has entered a period of rapid transition away from traditional sources of generating electricity (such as coal-fired generation) and towards newer technologies such as solar and wind generation.

3.6 The initial stages of this transition have been extensively documented in the NEM and, underpinned by strong technological, market and policy fundamentals, this trend is expected to continue in the long term. The following two subsections summarise some of the key observations regarding the increase in VRE/IBR generation and the reduction in conventional synchronous generation, both in terms of the recent trends and forecasts of the long-term evolution of the NEM power system.

Increase in variable IBR generation

3.7 In recent years, the NEM has experienced significant growth in generation from VRE/IBR, such as wind and solar generation, and now has some of the highest penetration levels of such technologies in the world. In South Australia, where penetration is highest, wind and solar generation can now exceed total demand, as illustrated in Figure 3-1.

Figure 3-1: Proportion of energy demand served by wind and solar in 2018



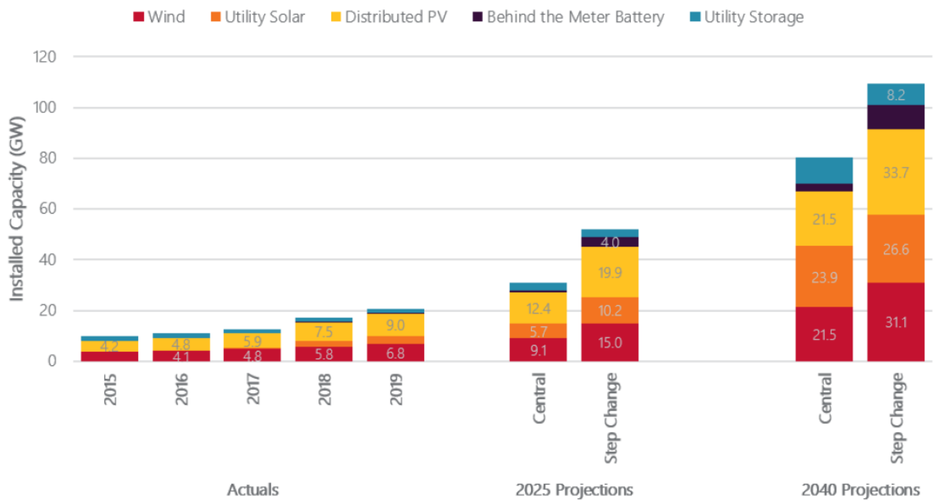
Source: AEMO, Maintaining Power System Security with High Penetrations of Wind and Solar Generation, October 2019 (link), page 9.
Note: The first column shows the proportion of annual energy provided by wind and solar in each region. The second shows the maximum proportion of wind and solar generation relative to system demand (regional or "native" demand). Numbers greater than 100% occur when generation is larger than native demand and the excess is exported.

3.8 In addition to the transmission-connected IBR resources, distributed behind-the-meter solar generation has also increased significantly, with installed capacity rising from 4.2 GW in 2015, to 9.0 GW in 2019.[68]

[68] AEMO, Draft 2020 Integrated System Plan, 12 December 2019 (link), page 18.

3.9 This trend of growing variable IBR, both utility-scale and behind-the-meter, is expected to continue, with all scenarios in AEMO's Integrated System Plan ("**ISP**") forecasting an increase in renewable capacity.[69] As shown in Figure 3-2 below, AEMO forecasts that by 2040, utility wind and solar would reach 45.4 GW in the Central scenario, and up to 57.7 GW in the Step Change[70] scenario. Similarly, the behind-the-meter solar capacity is estimated to reach up to 21.5 GW by 2040 in the Central scenario, or a 140% increase from 2019.

Figure 3-2: Current and forecasted wind and solar capacity



Source: AEMO, Renewable Integration Study: Stage 1 report, 30 April 2020 (link), page 18.

3.10 This level of renewables is very high in comparison to the total forecast demand for electricity. In the ISP Central scenario, the maximum penetration of wind and solar is expected to exceed 75% of underlying demand[71] by 2025, up from under 50% in 2019. In the ISP Step Change scenario, the maximum penetration is expected to be even higher, up to 100%. This is illustrated in Figure 3-3 below.

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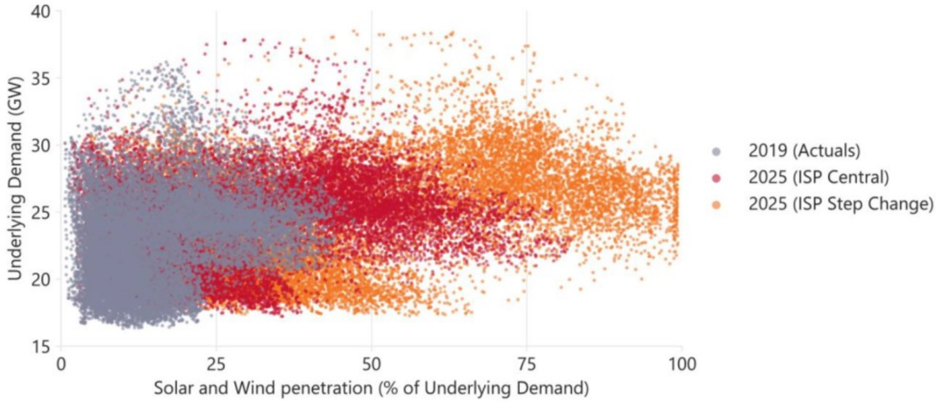
69 AEMO, Draft 2020 Integrated System Plan, 12 December 2019 (link), pages 37 and 41.

70 In the Step Change scenario, consumer-led and technology-led transitions occur "*in the midst of aggressive global decarbonisation and strong infrastructure commitments*". Source: AEMO, Draft 2020 Integrated System Plan, 12 December 2019 (link), page 28.

71 "*Underlying demand […] includes demand response, energy storage, and coupled sectors such as gas and the electrification of transport*". Source: AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 6.

Figure 3-3: Penetration of wind and solar generation



Source: AEMO, Renewable Integration Study: Stage 1 report, 30 April 2020 (link), page 19.

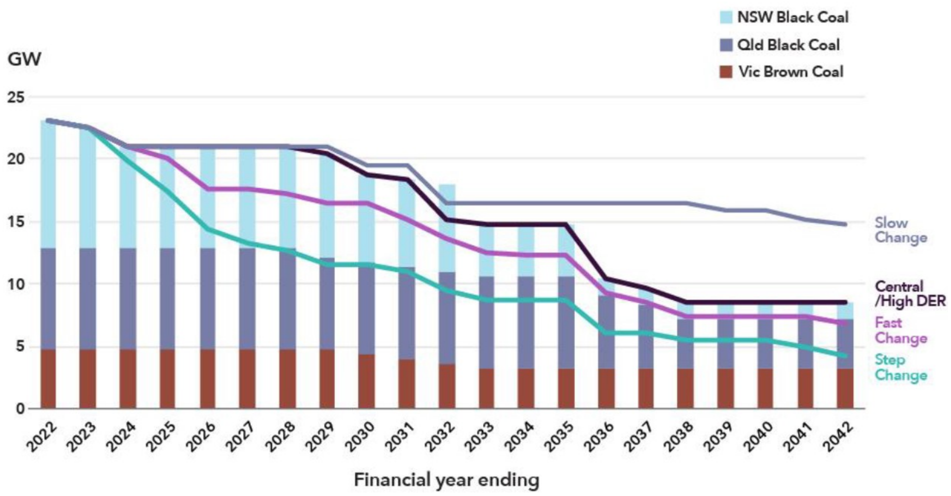
3.11 Such penetration of renewables deployment, relative to demand, is extremely high by global standards.

Reduction in synchronous generation

3.12 The recent increase in IBR generation has been accompanied by a decrease in synchronous thermal generation, most of which has been in black and brown coal power plants. This has been driven by the increasing competitiveness of IBR resources and policy ambition to increase renewables generation.

3.13 This trend is expected to continue, with synchronous generation forecasted to progressively decline as a share of the total generation, with coal-fired generation in particular falling as aging plants are retired. By 2040, the Central ISP scenario forecasts that approximately 13 GW of black coal plants and 2 GW of brown coal plants will retire across the NEM, reducing total coal capacity to 9 GW, down from 23 GW expected in 2022. In the Step Change scenario, this trend is even sharper, with total capacity falling to only 4 GW. This is illustrated in Figure 3-4 below.

Figure 3-4: Forecasted coal generation capacity



Source: AEMO, Draft 2020 Integrated System Plan, 12 December 2019 (link), page 42.

B. Impact of Recent and Expected Future Trends on the NEM

3.14 The two trends of growing IBR and declining synchronous generation described in the previous section manifest themselves in new challenges for the operation of the NEM power system. In this section we explore their impact on:

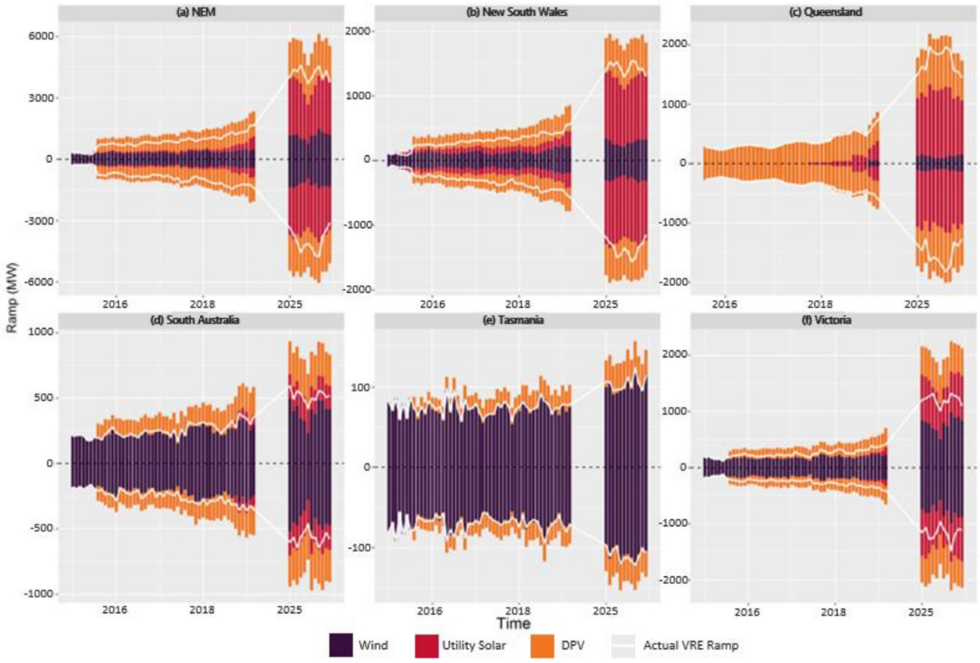
- net load;
- inertia;
- frequency performance;
- system strength; and
- AEMO costs of system operation.

3.15 Each of these impacts is described in turn below.

Increased uncertainty in net load

3.16 The increase in variable IBR generation and of behind-the-meter generation has increased the uncertainty and variability of net load across the NEM, i.e. the potential changes or "swings" in demand, net of behind-the-meter generation. Consequently, AEMO's analysis indicates that the ramps[72] have been increasing and are expected to continue doing so, as shown in Figure 3-5.

Figure 3-5: Actual and forecast largest hourly ramps



Source: AEMO, Renewable Integration Study: Stage 1 report, 30 April 2020 (link), page 57.
Note: Forecasts are for the Central ISP scenario.

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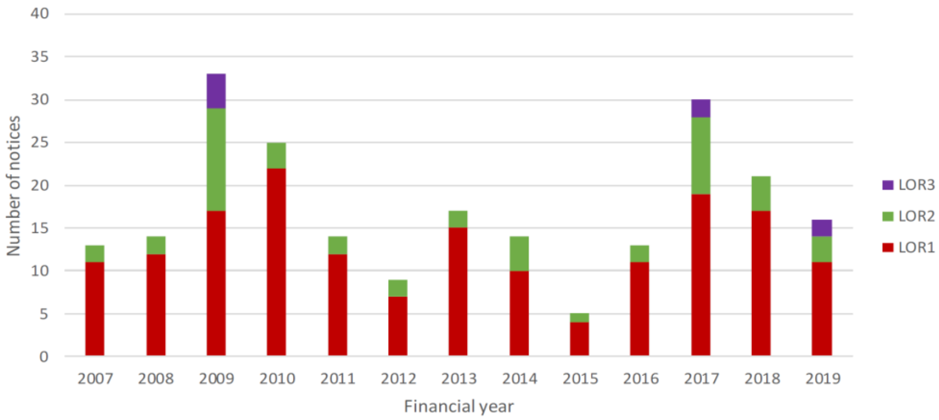
72 A ramp is an upward or downward fluctuation in the supply or demand for electricity and is a measure of variability within the system. Source: AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 56.

3.17 The increased variability in net load leads to a need for additional services to be available to meet the unexpected gaps in supply – this could be in the form of frequency response (to provide immediate stabilisation), or reserves (to address the energy gap). Storage assets, and batteries in particular, could be well suited to providing such services, with the price volatility associated with large ramps incentivising investment in such assets. However, if the investment signal is not sufficiently strong (or perceived as such by market participants), then price signals from volatility may not drive sufficient investment in increased supply or storage, leading to continued gaps in supply.

3.18 One manifestation of the volatility of overall supply and demand has been the number of instances where the system has been at risk of operating much closer to reliability and stability limits. For example, over recent years, AEMO has been frequently required to issue LOR notices to ensure that sufficient reserves are available to balance the fluctuations in demand and supply, as shown in Figure 3-6 below.

Figure 3-6: Lack of Reserve notices issued by AEMO



Source: ESB, The Health of the National Electricity Market 2019, 24 February 2020 (link), page 24.

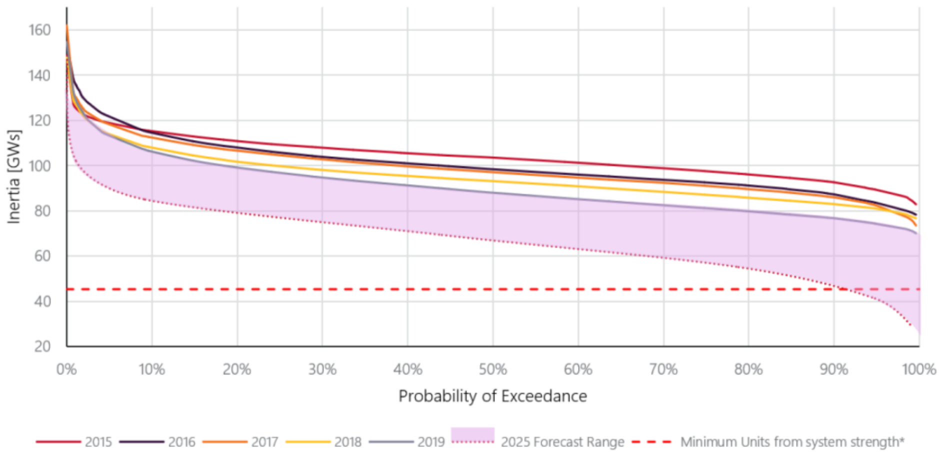
Falling inertia

3.19 As discussed in ¶2.34, inertia is produced by the rotating mass of traditional generation turbines rotating in synchronisation with the power system. Inertia "resists" change within the system and reduces the RoCoF following a disturbance. Falling inertia levels have therefore increased the variability and sensitivity of frequency to disturbances within the NEM.

3.20 Inertia levels within the NEM have been falling as synchronous generation provides an increasingly lower share of the generation mix, and are expected to continue falling in line with further displacement and retirements of synchronous generation (although some of this decline is expected to be offset through other investments, such as synchronous condensers – see ¶3.23 below).

3.21 As shown in Figure 3-7 below, historical levels of inertia have consistently exceeded at least 70GWs (in 2019) and even 80GWs (in 2015). However, AEMO is forecasting a range of inertia that could lie below 70GWs for over 50% of the time by 2025 and could fall, at 95% Probability of Exceedance ("**POE**") level, below 40GWs (half of the minimum level as of 2015).

Figure 3-7: NEM inertia levels – actual and forecast



Source: AEMO, Renewable Integration Study: Stage 1 report, 30 April 2020 (link), page 45.

3.22 Specific instances of inertia shortfalls have already been declared in the NEM. In South Australia, AEMO has used directions to remedy RT shortfalls in inertia for a number of years (resulting from changes in the generation fleet before market rules were changed so that AEMO would be required to undertake ex-ante assessments of future inertia and system strength levels).

3.23 More recently, under the minimum inertia requirements methodology (discussed in ¶2.40) forecasts of shortfalls have been declared for Victoria and Tasmania,[73] which the relevant TNSP must rectify. ElectraNet is installing high inertia synchronous condensers in South Australia, while TasNetworks has contracted inertia services from a provider. The long-term plan to mitigate the shortfall in Victoria is yet to be confirmed.[74]

Deteriorating frequency performance

3.24 The increasing variability and uncertainty of net load, combined with decreasing inertia levels and the associated impact on RoCoF, has made maintaining frequency within the normal operating band of 49.85-50.15 Hz increasingly challenging. This degradation of frequency control performance has been to a large extent driven by changes in the control system settings of conventional generators, where operators decreased or even removed the responsiveness of their plants to frequency deviations due to disincentives.[75,76] The impact of these trends is illustrated in Figure 3-8 below, which shows that the distribution of frequency in the NEM power system has been widening, i.e. the power system has been operating increasingly frequently outside of a narrow +/- 0.05Hz band.

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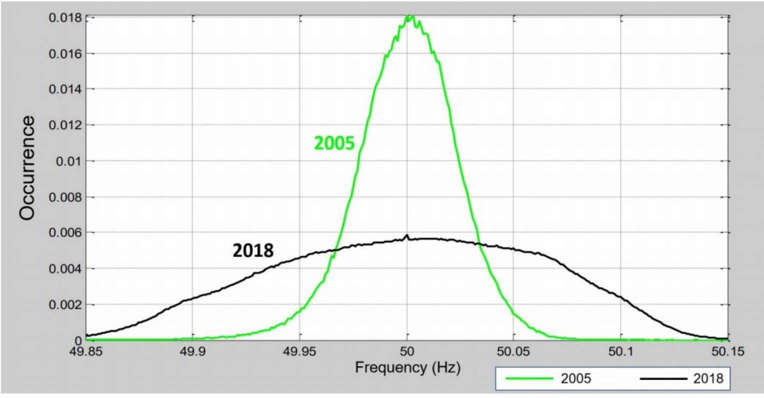
73 AEMO, Draft 2020 Integrated System Plan Appendices, 12 December 2019 (link), pages 206 to 209.

74 AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 29.

75 AEMC, National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, 26 March 2020 (link), page 7.

76 The recent introduction of mandatory primary frequency response in early 2020 may to some extent mitigate some of the frequency performance issues.

Figure 3-8: Degradation of frequency performance in the NEM

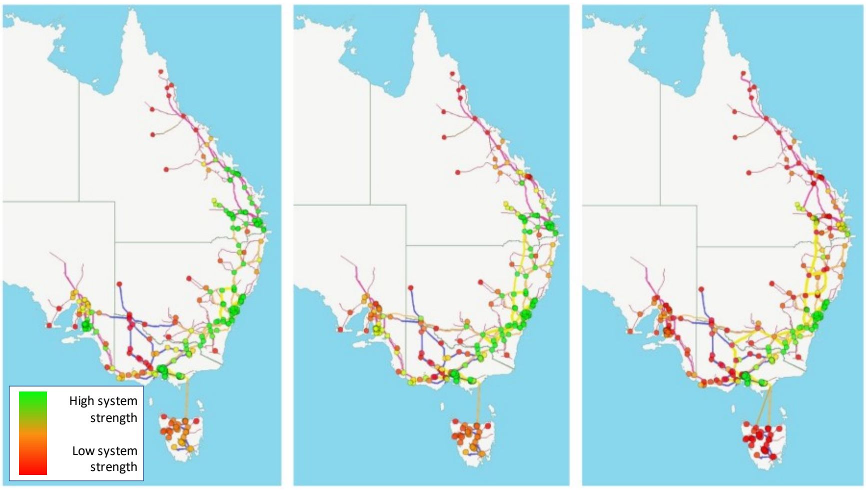


Source: AEMC, National Electricity Amendment (Mandatory Primary Frequency Response) Rule, 26 March 2020 (link), page 3.

Weakening system strength

3.25 Reductions in synchronous generation and its replacement with IBR has led to a progressively decreasing system strength across the NEM. System strength shortfalls have already been declared in South Australia, Victoria, Tasmania and Queensland.[77] In addition, low system strength is forecast to be an increasingly pressing issue, as demonstrated by Figure 3-9 below.

Figure 3-9: Forecasted system Strength in 2020-21, 2029-30, and 2039-40



Source: AEMO, Draft 2020 Integrated System Plan Appendices, 12 December 2019 (link), page 186.

77 AEMO, Renewable Integration Study: Stage 1 Report, 30 April 2020 (link), page 29.

Note: 2020-21 (left), 2029-30 (middle) and 2039-40 (right). ISP system strength modelling uses the Central scenario.

C. Case for Change

3.26 In light of the growing challenges to ensuring a secure operation of the NEM power system, the current NEM arrangements for procuring and scheduling ESS may need to be changed or adapted.

3.27 The urgency (or "criticality") of considering potential changes to the current arrangements would appear to depend on whether the **existing procurement frameworks** are fit for purpose to **meet the current and future system needs**. The current framework would be fit for purpose if, in our view, the following four criteria are met:

- The current framework clearly values and remunerates resources that provide the service, or otherwise mandates its provision. If there are poor operational and/or investment price signals for an adequate level of the service to be provided, then this indicates a potential need for change.
- The framework for such remuneration is structured and transparent. Conversely, if there are more ad-hoc processes, this would indicate a potential need for change.
- The system has been performing well in delivering secure supply of electricity to consumers. Conversely, if frequent security events have been identified, this would indicate a potential need for change.[78]
- The future technology and market changes are relatively limited and do not represent a step change in terms of challenges they pose to the system balancing. Conversely, if significant system changes are expected, driven for example by the continued growth of IBR and reduction in synchronous generation, this could indicate a potential need for change to the ESS provision. In particular, the ESS needs are likely to be different in a situation where the NEM transitions to a system with very high (dominant) penetration of renewables, which exacerbates system security (and potentially reliability) challenges.

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78 It is also possible that the system may appear to be performing well mainly because the SO has been significantly involved (e.g. through out-of-market actions) in maintaining system security. In such a case there may also be a potential need for change.

3.28 The extent to which these criteria are met would tend to correlate with the extent of the case for a change to the current approach. As such, in Table 3-1, we present a summary evaluation of these four factors, based on the analysis in Sections 2 and 3, and draw out the implications for the urgency of considering changes to the procurement of different ESS.

Table 3-1: Case for change: urgency of procuring ESS in the NEM

System service	Service value, compensation and cost recovery	Existing procurement	Current SO involvement to maintain system performance	Future drivers of need
Operating reserves	RT price signals No explicit 'payer' of costs	Structured process (self-scheduling)	Some observed reduction in margins with fewer resources available to be called upon.	Future demand driven by growing IBR and distributed generation, resulting in higher ramping needs, larger net load swings and lower predictability. Particular need during the transitional period away from legacy slow-start generation technologies. ?
Strategic reserves	Poor price signal due to out-of-market actions Costs paid for by AEMO (recovered from consumers)	Structured process (RERT, clear framework, ongoing reviews)	RERT appears to deliver required levels of SR (but ad-hoc).	
Frequency response	Resources paid for FCAS Costs paid for by AEMO (recovered from consumers / generation) No payment (currently) for MPFR (under review)	Structured process (FCAS, ongoing reviews, clear process for change -e.g. Infigen)	Falling frequency performance (recently and expected going forward)	Continued growth in non-dispatchable VRE (including behind-the-meter distributed generation), along with reductions in dispatchable thermal generation, likely to continue increasing variability of supply and demand and the need for frequency response ?
Inertia	No explicit compensation for by-product of energy Costs paid for by AEMO (through directions) or TNSPs (through regulated investments or contracts with gen), and recovered from consumers	- No price signal to invest unless and until expected shortfall declared - Ad-hoc (directions, investments by TNSPs, low transparency)	Falling inertia levels, high number of future shortfalls declared.	Continued reduction in synch gen (closure and/or withdrawal from dispatch), e.g. coal and gas fleets. Risk of future self-reinforcing loop of losing inertia where, for example, distributed generators rely on RoCoF relays and can trip in response to changes in frequency, which can in turn lead to a cascade of plant trips and accelerate the loss of inertia. ?
System strength	No explicit compensation. Lack of incentives to invest in / provide the service Costs paid for by AEMO (e.g. through directions) or implicit payment through system standards	Ad-hoc (directions, investments by TNSPs)	Falling system strength levels (identified through proxy metrics), high number of future shortfalls declared.	Reduction in synch gen (closure and/or withdrawal from dispatch), expected to continue to be displaced by IBR, shortfalls are likely to be an increasing issue in the future. ?
Voltage control	NSP responsibility Costs paid for by AEMO (e.g. through directions) or implicit payment through system standards	Ad-hoc (network configuration, contracts with NSPs and generators, mandatory tech requirements)	No major shortfalls identified.	Need for reactive power and voltage control services to continue to be driven by the decrease in synchronous generation Potential future reductions in minimum demand on bulk power systems (e.g. observed in GB) are likely to cause voltage issues Increasing number of connections of non-synchronous generation in low strength parts of the system make voltage less stable and therefore harder to control and stabilise through injection/absorption of reactive power. Careful tuning/retuning of control response required. ?

Weakest case for change   Medium case for change   Strongest case for change

Source: FTI analysis.

Notes: The evaluation is qualitative, based on the information currently available and may change over time.

3.29 Overall, we find that the case for change to individual ESS is the strongest when:

- The system services are **not explicitly valued in the current framework** on an "ongoing" basis (e.g. strategic reserves, inertia, system strength), but rather they are only valued in situations where an expected shortfall is declared, and, as a consequence, an ad-hoc (and often costly) out-of-market action is taken by AEMO to mitigate such shortfall. Such an approach is non-transparent and does not provide strong investment signals for long-term provision of such services; and
- The expected transition to a VRE-dominated system is likely to exacerbate the recent observed trends and **increase the risk of major shortfalls** of specific services.

3.30 Based on the analysis performed in Table 3-1, the strongest case for change emerges for **inertia** and **system strength** as they both currently have an unstructured procurement approach with no identifiable remuneration. The resulting lack of investment signals leads to a high risk of significant service shortfalls.

3.31 In addition, in light of the deteriorating frequency performance and increasing variability of supply (see Table 3-1) there may be a case for change for **frequency response.** We recognise that there is a structured framework (FCAS) for providing this service, but the potential changes could entail strengthening price signals where needed (e.g. for the MPFR) and/or refine specific FCAS categories to better meet future system needs (e.g. faster response), and/or further co-optimisation of other ESS (not just energy).

3.32 There may also be a case for changing the current reliance on market provision of **operating reserves** – the decision would hinge on the trust that the market will continue to self-procure a sufficient volume of reserves. This decision may also be driven by considerations of system reliability in the NEM's current reserve arrangements (as opposed to system security, which is the focus on this report).This is discussed further in a separate post-2025 ESB workstream on Resource Adequacy Mechanisms.

3.33 There may also be a case for considering potential changes to how **strategic reserves** are procured for security and/or reliability purposes: we recognise that strategic reserves are procured under the NEM reliability standard, and that this service has been extensively refined over the recent years.[79] To date, its provision appears to lead to adequate levels of security and reliability, but the current structured procurement approach could potentially provide a poor long-term investment signal.

3.34 The structured procurement of strategic reserves can also lead to a "**slippery slope**" phenomenon: a situation where, in essence, strategic reserve plants are on standby to provide energy in cases they are called upon to do so, typically at pre-agreed prices. Meanwhile, in-market resources that would normally rely on a small number of very high peak prices to be economically viable may no longer observe such high wholesale market prices[80] (or not as frequently), as the SO would intervene by dispatching strategic reserve plant to mitigate the system stress event (this is the case even if resources that are procured via structured mechanisms are prevented from bidding directly into the wholesale market). This would have an effect of dampening the overall wholesale market price, which in turn, reduces the payments to all generators not receiving the targeted payment. Everything else being equal, this deters investment that is not the recipient of a targeted payment, particularly peak plant investment. In turn, this is likely to lead to a need to widen the scope of the targeted payment to induce the necessary investment – thereby perpetuating a slide towards an increasingly large targeted scheme.

3.35 The case for change for voltage control / reactive power appears to be less acute compared to other services, although this may need to be revisited in the future if any of the four criteria assessed in Table 3-1 evolve.

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79 For example, in 2019 RERT was enhanced, linking the procurement of strategic reserves to the reliability standard and increasing the maximum procurement lead time to 12 months. Source: AEMC, National Electricity Amendment (Enhancement to the RERT) Rule 2019, 2 May 2019 (link), page 28.

80 However, the intervention pricing mechanism included within the RERT, which runs a counterfactual dispatch to calculate the "what-if" prices and quantities, is designed to mitigate this issue.

3.36 In addition, there is a potential **case for change for the ESS as a group of services** given the strong interrelationships among them (see Section 2B above). Even in cases where a particular service appears to be working well in the current NEM design, it may be appropriate to reconsider its procurement holistically – i.e. in the wider context of the suite of ESS as a whole. This relates closely to the potential desire for service co-optimisation which is discussed below in Section 5.

3.37 Finally, it is important to ensure that the ESS arrangements (whether through in-market or structured provision through NSP-led development or through technical standards) continue to support the system needs over all timescales and that they are robust across different potential evolutions of the NEM. While the description above focused on the long-term NEM outcomes, the design should also ensure that system needs are also met in the interim stage, i.e. while the NEM progresses on the transition to the VRE-dominated system.

- In the current and near-term future, the system should make a good use of existing resources, while progressively introducing new resources to contribute commensurately with their technical capabilities (e.g. initially through trials of new technologies).
- In the longer term, the new resources are likely be the main (if not only) ones supporting the system and the procurement and scheduling design should therefore be able to adapt appropriately to the gradual change in the resource mix.

3.38 This is explored further in Section 8 on the flexible regulatory framework.

4. Principles for ESS procurement and scheduling

4.1 Based on the "case for change" set out in the previous section, policy makers may consider making potential changes to the existing ESS procurement and scheduling arrangements in the NEM. In this report, we propose a common set of criteria that seem most likely to represent good policy outcomes, such that the ESS design helps "*promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity*".[81]

4.2 In this section we present a set of key principles that we consider appropriate to apply when considering any potential changes to the current ESS arrangements, in order to deliver a secure NEM system in the long run.[82] These key principles are:

- Operational efficiency;
- Efficient investment signals;
- Risk allocation/cost recovery;
- Proportionate procurement;
- Transparent process;
- Adaptability; and
- No undue discrimination.

4.3 Each of the principles is described in turn below.

A. Operational efficiency

4.4 The procurement design should facilitate an **overall efficient dispatch**, for a given set of resources available.

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81 National Electricity (South Australia) Act 1996, Version 1.7.2019 (link), page 43.

82 These principles have been informed by the international experience with system services (for example, National Grid Electricity System Operator Procurement Guidelines, effective from April 2019 (link), as well as ESB's Post 2025 Market Design Issues Paper (September 2019), ANNEX A: Assessment Framework (link).

4.5 To deliver such dispatch, the market design should provide **efficient price signals in operational timeframes** to ensure availability and utilisation of existing resources. Where services are provided, but not remunerated, this may need to be reviewed to ensure that this does not lead to inefficient outcomes (e.g. where the SO is required to take unnecessarily costly out-of-market actions). In the absence of RT price formation for a particular service, the ESS procurement framework should aim to fairly reward all providers of that service.[83]

4.6 To support operational efficiency, all resources should be considered as potential providers of ESS, and the most economical resources should be selected, subject to appropriate considerations in terms of quantity, quality and nature of service.[84] This is closely related to the principle of "no undue discrimination" (or technology neutrality) that is discussed further below in this section. Together with the principle of investment efficiency (see subsection B) this indicates a need to explicitly value and reward existing synchronous generation for the services provided to the NEM.

4.7 Where possible, the procurement of system services should be based on voluntary bids and offers from market participants, although this may need to be, in some cases, subject to rules that mitigate the exercise of market power.

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83 This reward could be provided through an in-market design (a common clearing price, which may be zero, for all resources providing the service during relevant period) or an out-of-market design (e.g. availability payment for resources pre-contracted with AEMO). In general, it is challenging to design a regime where only the marginal units providing a particular service receive the payment, as this tends to distort economic incentives for the inframarginal resources, and therefore a reward to all resources providing the service tends to be preferable. For location-specific services, this requires an additional consideration of which services are actually providing the service to meet the (locational) need.

84 NGESO, in procuring services, will "*purchase from the most economical sources available to us having regard to the quality, quantity and nature of such services at that time available for purchase*." Source: National Grid Electricity System Operator Procurement Guidelines, effective from April 2019, (link), page 10. See also "no undue discrimination" for ESS procurement in ¶4.36 below.

4.8 In general, the market design should seek to maximise market-based outcomes, such that the required interventions by AEMO are kept to a minimum. This does not mean that the role of AEMO is removed altogether: there are likely to be instances where ad-hoc interventions remain more appropriate than market-based outcomes, for proportionality reasons (see subsection D).[85]

4.9 The rationale for this would be that it is inherently preferable, from a market efficiency perspective, for multiple buyers and multiple sellers of a service that are privately commercially incentivised to interact in a marketplace (assuming a competitive two-sided market), compared to a situation where AEMO, as a not-for-profit and therefore non-commercial[86] entity, acts as the sole purchaser of such services. The extent to which this is feasible is likely to vary across different ESS and may also need to evolve over time.

B. Efficient investment signals

4.10 The ESS procurement design should promote efficient and timely investment in (and provision of) all relevant system services in order to deliver the desired level of reliability and security. In the absence of long-term investment signals, there is a risk that the shortfall of a particular system service only becomes apparent "too late", i.e. too close to RT for investment in relevant assets to be made (particularly if the lead time for making an efficient investment is long, say several years). In turn, this creates the risk that the volume and mix of resources available closer to RT may lead to higher than necessary costs of operating the system and may compromise the overall grid resilience.

4.11 The design should therefore provide appropriate and transparent investment signals for market participants to make long-term decisions to invest in necessary resources. The investment signals should also be consistent with the RT operational signals.

85 For example, when the need for a particular ESS is relatively low, it may be more efficient for the SO to use ad-hoc interventions to provide the service. However, if the volume of the need increases over time, it may become more efficient to develop a more market-based solution to providing the service.

86 If AEMO was a commercial entity, it would be able to achieve similarly efficient outcomes, provided there was sufficiently competitive supply. However, designing incentives for a non-profit SO to mitigate the risk of inefficient procurement (in terms of quantum and/or price) is inherently difficult, as discussed in Section 8.

4.12 Spot markets are one, but not the only, way of providing efficient investment signals. Typically, there needs to a be a supportive environment for spot markets to deliver efficient outcomes, including two-sided markets (i.e. numerous buyers and sellers) and liquid secondary trading markets. When the conditions for efficient spot markets are absent, as might be the case for services that can only be provided by a small number of parties, it may be appropriate to consider alternative mechanisms to provide efficient investment signals, such as regulated approaches.[87]

4.13 The investment signals are driven by the remuneration that resources can reasonably expect to earn for the provision of the service. As with operational efficiency, it may be necessary to review instances where certain services may be provided but not remunerated. To remunerate the provision of a service it is necessary to (i) identify the party who has provided a particular service and (ii) measure its provision. While this may seem obvious, this is not always easily observable. For example, it is not, currently, straightforward to estimate how much additional system strength is provided by a specific additional unit of synchronous generator online (see Box 2-1 in Section 2 above) and therefore the provision of system strength may need to be based on a proxy measure (e.g. another metric associated with the provider of the services).

4.14 The design of appropriate investment signals should also differentiate between short-term and long-term incentives of service providers. For example, allowing ESS providers to recover only the actual costs of providing the service (cost-based) is highly cost-efficient in the short term. However, this approach runs the risk of making the provider indifferent to providing the service in the long run and does not necessarily enable them to recover the costs of maintenance and upgrades required to be able to deliver the service on an enduring basis. The cost recovery approach therefore needs to ensure that appropriate investment signals are maintained for long-term provision of ESS.

C. Risk allocation/cost recovery

4.15 An appropriate allocation of risks and cost recovery in relation to the provision of ESS is critical to ensure that all resources are appropriately compensated for the value they provide to consumers. The two issues are considered in turn below.

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87 Standard monopoly regulation is a typical example of a situation where services cannot be provided through spot markets as there is only one potential provider of such services. Network incentive regulation is a common approach to achieving an approximation of an efficient outcome.

4.16 First, the **risks associated with the provision of ESS should be borne by participants best able to manage them**. This is particularly relevant in allocating the risk of uncertain future revenue from providing an ESS, as discussed in Box 8-2 in Section 8.

4.17 Second, we consider that it would be reasonable for cost recovery to be based on the "**causer-pays**" principle. This involves identifying the party responsible for causing a particular system imbalance (which triggers the need for an ESS) and allocating the costs of that service to them. This principle has a strong appeal, as it can provide strong operational and investment signals as discussed in the previous subsections.[88]

4.18 However, this principle faces some key challenges and may sometimes lead to unintended consequences:

- It may not always be practically feasible to identify the "causer" for every physical disturbance to the system;
- The procurement of system services is driven by the projected need for the service[89] (e.g. based on historical variability in the supply/demand balance), rather than the actual usage;
- The actual cost faced by "causers" may be unknown at the time of the investment decision; and
- The sunk nature of investments may lead to inefficient use of resources in RT.

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88 There might be cases where a particular system service is required by a market participant (other than the SO), in which case the costs of providing such service should be allocated to that party. NGESO states that: "*If a third party requires Balancing Services, and if we secure provision of such services on their behalf, the associated costs of provision will be fully recharged to the party requiring such services.*" Source: National Grid Electricity System Operator Procurement Guidelines, effective from April 2019 (link), page 11.

89 This may be a reflection of the procurement approach rather than the cost allocation approach: for example, SO purchases a specific quantum of FCAS ex-ante (without knowing how resources will perform in RT), some of which may go unused and may appear unnecessary. However, in the long run, the causer-pays cost allocation is likely to incentivise desirable behaviour by resources in RT, such that the quantum of FCAS procured will end up lower than it would have been if the costs had not been recovered through the causer-pays principle.

4.19 As an alternative, a "**beneficiary-pays**" principle could also be considered. Under this principle, the cost of maintaining security of supply (e.g. the cost of a corrective action taken by the SO) would be allocated to those who benefit from a stable system. This could be both consumers, who benefit from a secure energy supply, but also resources (generators, storage and demand response), who benefit from access to a network that enables them to earn revenues (e.g. without being disconnected).

4.20 However, due to the public good nature of security of supply, it is challenging to identify specific beneficiaries (and who benefits more than others). This leads to a risk that additional system services may be procured and paid for by consumers, but where the cost savings (or value) of those services are not passed through to consumers.

4.21 The marginal decision on whether to procure additional system services for the benefit of consumers should therefore be linked to the value of the incremental service that accrues to (and is captured by) consumers[90] relative to the cost borne by consumers.

4.22 As a result, it has not been straightforward to implement the "causer-pays" or the "beneficiary-pays" principle due to challenges associated with measuring and monitoring the causers of the need for the service; or the beneficiaries of the service. In practice, a degree of cost smearing (at least partially) across the network users has often been used instead.

4.23 For example, in the NEM, the causer-pays principle has been applied alongside cost smearing. Regulation FCAS is charged on the basis of causer-pays, while contingency FCAS costs are allocated on the basis of a high-level approximation of who the "causers" are: low frequency (indicatively "caused" by generators reducing supply) is smeared across generators, while high frequency (indicatively "caused" by consumers reducing demand) is smeared across consumers.

[90] This can be proxied for example through consumers' willingness to pay for increased security of supply.

4.24 However, the application of the causer-pays principle for regulation FCAS has been subject of extensive debate. AEMC's frequency control frameworks review identified a number of issues with this approach, including a "*temporal disconnect between a market participant's contribution to the need for regulating FCAS and the costs charged to that market participant*"[91] and a lack of transparency and simplicity in relation to cost calculations. AEMO also conducted a review of the causer-pays arrangements in 2018 and concluded that a number of issues existed with the current arrangements, including those relating to (i) the calculation of contribution factors when regulation FCAS requirements apply within a local region; (ii) the treatment of non-metered generation; and (iii) the profile that is assumed when determining deviations.[92] AEMC intends to revisit the causer-pays arrangements as part of its assessment of AEMO's rule change request on the removal of disincentives to the provision of primary frequency response (see ¶2.32).

D. Proportionate procurement

4.25 The procurement mechanism used should be appropriate to each individual system service – which might mean that the mechanism may vary depending on the service being procured.

4.26 The range of options include provision through the market, through contracts with a central party (typically the system operator), or as a regulated asset (e.g. through the TNSPs). A further dimension is whether provision should be through ad-hoc interventions to ensure market security, through formalised auctions or through other procurement mechanisms. For each option, the costs of undertaking the approach to procurement should be weighed up against the benefits of that approach (this is explored in more detail in Section 6 and Section 7). As a high-level illustration, three examples can be compared:

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91 AEMC, Frequency Control Frameworks Review Final Report, 26 July 2018 (link), page 76.

92 AEMO, Regulation FCAS Contribution Factor (Causer Pays) Procedure Consultation Final Determination, November 2018 (link).

- **Ad-hoc procurement of a system service ("low cost").** Ad-hoc actions, such as directions, may be attractive to the SO in the short term because it is likely to be less costly from an administrative perspective and also quicker to implement from a practical perspective. However, in the longer term, such an approach is likely to lead to relatively weak cost pressures on resources providing the service, compared to a more structured approach (as discussed in the next bullet), and therefore deliver lower benefits to consumers.
- **Structured (market-based) procurement of a system service ("high cost").** This is likely to be more administratively costly, as it may require an auction style process or a market platform to be set up, administered and monitored. However, it may lead to more competition and therefore lower prices for purchasing that service. There may be additional benefits from this approach such as the transparency of an auction and the price signals emerging from an auction process might have dynamic efficiency benefits in that it might send investment signals to market participants (to enter or leave the market).
- **Mandatory technical and performance standards ("unobserved cost").** For some services it might be that ESS can also be provided through an obligation on participants (e.g. MPFR), in that the resource is subject to technical standards or requirements that oblige it to provide the service as a condition for, say, accessing the transmission network. In this context it would also be worth assessing whether the costs and benefits of this approach are proportionate, in that provision by the participant may not be costless and, ultimately, these costs will need to be recovered from customers.

4.27 Based on the examples set out above, the approach to procurement should weigh up the benefits and costs of a particular approach and select a proportionate one. For example, a high-cost approach may be selected when the benefits are also expected to be high, but a low-cost approach is preferable when the benefits are expected to be low. In any event the selection should avoid outcomes with "high cost low benefits", which would not be proportionate.

4.28 The different options are described in more detail in Section 5 below.

E. Transparent process

4.29 The need for ESS should ideally be specified in a transparent manner, in order to provide investment and operational price signals. For example, where the service procurement is carried out centrally (e.g. by a system operator as opposed to the market participants themselves), the central entity should be responsible for articulating how much of the services are being procured. For example, this can specify:

- A minimum level of services required to support the system operation; and
- Additional levels of service that may be procured to deliver additional objectives (e.g. facilitate the deployment of additional IBR while maintaining secure operations; or increase the level of system security and overall grid resilience).

4.30 The procurement of ESS should be transparent to market participants, so as to encourage participation in the short run and market entry/exit in the longer term. In turn, this is likely to promote the efficiency of delivering the services, and thereby reduce costs to consumers. In practice this means that:

- The **requirements** for the provision of a service should be communicated in a timely and clear manner to all relevant parties. In the context of a competitive process, this could include the quantum of service required (based on a projection of future needs), timelines, evaluation metrics, template contract and other information necessary for the process.[93]
- The **outcome** of any procurement process should also be communicated in a timely and clear manner to all relevant parties so that they can make informed decisions (e.g. in terms of investment or closures, innovation or future bidding and wider commercial strategy). Both the successful providers, unsuccessful providers and prospective future providers of the service, in addition to wider stakeholders, need to understand (i) why the services have been procured (i.e. the "need" that the service meets); (ii) price paid to successful providers and associated conditions (e.g. availability requirements); and (iii) the benefits derived from the procured services.

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93 NGESO, in procuring commercial ancillary services, provides "*a statement indicating the processes and terms under which contracts will be awarded*" and publishes the requirements for the service on its website. Source: National Grid Electricity System Operator Procurement Guidelines, effective from April 2019 (link), page 10.

F. Adaptability

4.31 As system needs, markets and the technology evolve, the procurement of ESS should be able to adjust accordingly in order to continue to meet consumer needs in an efficient manner. While a rigid system, in which the nature and volume of ESS products procured is fixed, may have some benefits in terms of providing market participants certainty, it may also run the risk that (i) services that are no longer required continue to be procured; and (ii) new or amended services fail to be introduced in a timely manner. In turn, this might risk the SO (on behalf of consumers) incurring excessive costs in operating the system.

4.32 The need to adapt the range of system services over time is a common experience internationally. For example, in 2017 NGESO initiated a wide review of its ancillary services procurement across GB, the first stage of which was to "rationalise" the products on the grounds that a "*number of products are no longer required in their current form, or have been superseded by later products. We are therefore proposing a review to reduce the suite of products that we procure*".[94]

4.33 The ESS procurement should also support and encourage innovation and "learning by doing". For example, NGESO explicitly plans for procuring "trials" of new system services and to communicate them transparently to the market.[95]

4.34 Finally, the ESS procurement should be able to adapt to the introduction of new technologies such that any cost savings or improvements in the quality of service from new technologies may be tested and implemented in a timely manner, for the benefit of consumers. This is closely linked to the "no undue discrimination" principle discussed below (and the technology neutrality that underpins it). For example, the ESS procurement should be able to adapt to:

- the emergence of new technologies for providing system strength (e.g. through "virtual synchronous machines" – see ¶2.49 above); or
- new methods for measuring the amount of inertia on the system (which may help adjust the volume of inertia procured as a service).[96]

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94 National Grid, System Needs and Product Strategy, June 2017 (link), page 32.

95 When running trials for ancillary service, NGESO publishes on its website "*the timelines, purpose and results of these trials in the Market Information Reports, or through the Network Innovation publications*" Source: National Grid Electricity System Operator Procurement Guidelines, effective from April 2019 (link), page 11.

96 Energy Live News, Reactive Technologies and National Grid ESO partner to fulfil 2025 zero carbon goals, 5 August 2019 (link).

4.35 The application of this principle is explored further in Section 8, where we discuss the form of a future regulatory framework for the provision of ESS.

G. No undue discrimination

4.36 The final principle for the procurement of ESS is that all prospective providers of any service should be treated equally insofar as technical and economic differences permit.[97] This would assist in delivering services required at lowest cost to consumers.

4.37 An important corollary to this principle is that it does not imply that all participants should be treated the same in all circumstances. There may be good justification for why one participant is treated differently to another. For example, a participant's location on the network relative to another or the speed at which it is able to provide a service might mean that a difference in treatment (and price paid for a service) is justified. That is to say that "due" discrimination should be allowed insofar as there are relevant technical or economic differences between the services different participants can provide.

4.38 The relevant technical and economic differences may include factors such as the cost structure or the price bid for the provision of the service (e.g. availability, ramping or utilisation of a resource), the nature of the service (for example, for frequency control, this may be the speed at which the resource is able to respond to a control room instruction), or the historical performance of the provider.

4.39 Potential providers of ESS may include conventional generators (injecting power or operating in synchronous condenser mode), IBR, storage, DER, interconnectors, demand response, synchronous condensers, and any other relevant resource. Going forward, the market design should also appropriately reflect the capacity of new resources to contribute to ESS: this may include new, as yet unknown, technologies, or new ways in which existing resources can contribute to the relevant needs of the power system. For example, the ability of transmission networks to "transport" system strength to geographically wider areas, or the operation of "virtual synchronous machines" could be included, commensurately with their economic and technical characteristics, among potential contributors to system strength.

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[97] NGESO states that "*after having taken relevant price and technical differences into account, we shall contract for Balancing Services in a non-discriminatory manner*". Source: National Grid Electricity System Operator Procurement Guidelines, effective from April 2019 (link), page 19.

4.40 Inclusion of a wide range of participants to provide ESS (without undue discrimination) would help support the earlier principles of efficient investment and operational prices signals by increasing the competitive pressure and incentivise innovation.

4.41 While the ESS procurement design should allow market participants to respond to incentives without risk of undue discrimination, it is also worth noting that, in some circumstances market power mitigation tools may be required. For example, a market participant located strategically on the network might be the sole provider of a particular service and could potentially exploit their market power inappropriately. This is particularly relevant for services that can only be met with a narrow set of resources.[98]

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98 For such services it is necessary to apply the “proportionality” principle discussed above to assess whether or not the expected benefits of increased competition (likely to be low) outweigh the expected costs of developing a competitive procurement and scheduling regimes.

5. Key design parameters

5.1 The procurement and scheduling process of current and future ESS can be characterised at a high level by a number of features, referred to in this report as “design parameters”. To understand how the existing ESS can be adapted and evolved in the future, we first describe the key dimensions that are most relevant in defining potential future models for procuring and scheduling ESS and consider how they can be adjusted.

5.2 In this section we describe the key design parameters of ESS and introduce the main variants and levers that may be considered for the future ESS arrangements. We focus on the following design parameters:

- Co-optimisation (**Section A**);
- Centralised vs decentralised procurement (**Section B**);
- Target setting (**Section C**);
- Geographical granularity (**Section D**); and
- Procurement timeframe/resource commitment (**Section E**).

A. Parameter 1: Co-optimisation

5.3 As we noted in Section 2B, to varying degrees, ESS are interdependent in that the provision of one service might, on some occasions, reduce the requirements for another service. At the same time, a single resource may be able to offer multiple services[99] which can be traded-off for an optimal combination.

[99] For example, a generator may provide active energy, or remain offline and thus provide operating reserve. Similarly, a generator can trade-off the provision of energy and FCAS by providing more of service and less of the other.

5.4 This partial substitutability and multi-service delivery from a single resource offers the scope to co-optimise ESS by trading-off the procurement and dispatch of different system services in order to achieve the lowest overall cost and to optimise the selection of resources which provide those services. For example, depending on system conditions at a particular time, it may be preferable for a system operator to procure a large volume of a relatively cheap service compared to a small volume of a different, more costly, service if each achieves the same overall objective. Alternatively, the system operator may identify trade-offs between the provision of different services by a particular resource. These two aspects of co-optimisation can refer for example to groups of system services (e.g. fast and slow frequency response services), or to combinations of bulk energy and a system service (e.g. existing co-optimisation of energy and FCAS in the NEM).

5.5 The degree of co-optimisation among ESS and energy can vary from a fully siloed approach to a fully co-optimised approach, with a range of variants in-between.

Fully siloed approach

5.6 In this approach, each service (and bulk energy) is procured in "silos", i.e. without any trade-offs between services being considered.

5.7 The main disadvantage of a fully siloed approach is that each service is procured in isolation from other services and therefore any cross-dependencies (or substitutability) among those services is not taken into account. For example, when procuring a particular level of frequency response, it is important to understand what the underlying levels of system inertia are expected to be: for higher levels of inertia the volume of frequency response service may need to be lower as the system is more resilient to any RoCoF.

5.8 Conversely, a potential advantage of a siloed model is that it enables services to be procured on a standalone basis without necessarily implementing complex changes to the existing services. This could be valuable if the need for a service is uncertain (e.g. the SO is looking to "trial" a service, not being certain whether it is likely to be successful) and/or temporary (e.g. there may not be an ongoing long-term need for the service), and therefore it would be disproportionate to implement a co-optimised model.

5.9 An additional advantage of a siloed model may be that it enables very specific and (narrow) or very high-value services to be defined and procured in a highly targeted manner, and thus allows well defined product markets to develop. This could therefore be a simple and transparent approach that could provide operational and/or investment signals to the market.

Mixed approach

5.10 In this approach, some groups of services are co-optimised, while others are not. This is a common approach in many international jurisdictions and already exists in the NEM, although there are significant differences among countries in the exact application. The critical design parameter is where the line is drawn between services that are co-optimised and those that are not.

5.11 Currently in the NEM, energy and FCAS are co-optimised in dispatch. The general consensus is that this has worked relatively well, and the main design question is whether any other services should also be co-optimised.[100] However, the current system is imperfect as the eight FCAS markets are not fully co-optimised with each other (although the impact is not thought to be a material issue).

5.12 The experience in other international power systems provides several key insights:

- In GB, NGESO typically procures new services in “silos”, without co-optimisation with energy (or other services). The SO has been reforming the ESS, with considerable discussion as to whether the products should be more standardised or more diversified, as illustrated in Figure 5-1 below. Standardisation would involve precisely defining a relatively high number of specific individual products that each fit a specific operational need, whereas diversity would result in fewer “silos”, where a smaller number of products would be defined, each potentially serving multiple needs.

Figure 5-1: Trade-offs between standardisation and diversity of ESS

Source: National Grid, System Needs and Product Strategy, June 2017 (link).

100 In this report we do not examine the potential for de-co-optimisation of energy and FCAS.

- As part of the wider reforms, NGESO has indicated a preference to move towards a more standardised approach and has embarked a on process to simplify the ESS through standardisation and greater transparency of the procurement process.[101]
- To date, services typically remain procured through individual targets and tender processes, which does not allow for an explicit trade-off the forward provision of different services. However, there may be a potential for deploying the resources in RT in a way that co-optimises services with energy, although this approach has its own challenges (see Box 6-1 in Section 6). Importantly, the learnings from GB are incomplete as not all ESS covered in this report (and under consideration in the NEM) are procured by the NGESO (see Appendix 1).[102]
- In the US, some markets have system services (notably frequency response and reserves) that have been increasingly co-optimised with energy, in pursuit of efficiency gains and cost savings. For example, NYISO co-optimises four distinct ancillary service products in the day-ahead market and RT dispatch: regulation, 10 minute spinning reserves, total 10 minute reserves and 30 minute reserves. MISO and Ontario IESO also co-optimise the procurement and pricing of energy and several ancillary services in the RT dispatch, while PJM and Independent System Operator ("**ISO**") New England do this to a limited extent. The Electric Reliability Council of Texas ("**ERCOT**") co-optimises energy and ancillary services in the day-ahead market and is moving towards implementing similar co-optimisation in the RT dispatch. In general, co-optimisation of nested ancillary services is a tried-and-tested concept in many North American ISOs (see Appendix 1 for more detail). The arrangements regarding pricing, penalties for non-delivery, as well as the technical ability to co-optimise have been successfully developed, implemented in practice and refined over time, and could be drawn on as part of a more detailed market design in the NEM.

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101 In 2017, NGESO initiated a process of rationalisation, simplification (standardisation) and improvement of the ancillary services. This process has been broadly supported by market participants and resulted in standardisation of some of the existing frequency response and reserve products. Source: National Grid, Product Roadmap For Frequency Response and Reserve, December 2017 (link) pages 1 and 3.

102 System strength is not explicitly considered. Inertia is also not a standard product procured by NGESO, although pathfinder, a new inertia product was procured in 2020. Source: NGESO, National Grid outline new approach to stability services announcement, 29 January 2020 (link).

5.13 Based on the above, a spectrum of different options for future NEM market design can be envisaged which ranges from a fully siloed approach (as with GB), to a fully nested, co-optimised approach (the direction of travel for many North American ISOs):

- At one end of the spectrum, a **siloed approach** involves procurement and pricing of new service(s) (such as reserves[103]) that is separate from the co-optimised FCAS and energy. In this variant, the new service(s) are procured through individual silos, with co-optimisation within each silo, but not between the separate silos.

- At the other end of the spectrum, in a **nested, co-optimised approach,** the capacity procured to meet one target would, where appropriate, count towards specified other targets.[104] This could be implemented either for energy, frequency and reserve products (where precedent is available from other international jurisdictions), or for new services (e.g. inertia). In this variant, there may also be a potential separate silo for offline quick-start reserves that would generally be self-committed but would be available for commitment by AEMO in specified circumstances.

5.14 In parallel, the co-optimisation process also involves the choice of services provided by specific resources (even if the quantum procured of each service remains the same), as some resources can provide multiple services. This aspect of co-optimisation therefore seeks to deploy each resource most efficiently among the potential options in which it can operate.

Fully co-optimised approach

5.15 This approach seeks to identify a global minimum of all costs of meeting demand, by considering all trade-offs across all system services and energy. This includes NEM-wide services, as well as primarily local services such as voltage support and system strength.

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103 This could also be a new service such as inertia, or system strength or others. The main design feature here is that the new service is not co-optimised with energy/FCAS.

104 For example, the procurement of operating reserves would count, perhaps partially, towards strategic reserves.

5.16 In general terms, the cost-reducing feature of co-optimisation is desirable. However, there may be downsides to focusing exclusively on a fully co-optimised approach for all services and at all times. The expected benefits of co-optimisation therefore need to be weighed up against:

- **Risks of mandatory bundling**: If a poorly designed co-optimisation process leads to services being provided jointly, there may be a risk of paying extra for a superfluous service. It is essential that any trade-offs embodied in the dispatch and pricing software be consistent with operating practice.
- **Risks of excessive complexity**: Co-optimisation may introduce a layer of additional complexity to the system and entail significant costs (e.g. software and the development efforts), particularly for new services for which the appropriate trade-offs and operating practice may not be well defined based on past experience and therefore may be evolving over time. A staged approach, where ESS are initially procured in a silo, and later (if successful) incorporated in a co-optimised model, may reduce the risk of introducing unnecessary complexity to the system.
- **Risks of delays**: Introducing ESS solely on a co-optimised basis may also lead to delays in procuring such services (for similar reasons to those in the previous bullet). The urgency of procuring a particular service therefore needs to be balanced against the preference for co-optimised procurement.

5.17 There are additional challenges associated with co-optimisation of the full suite of services, set out below. While these do not prevent co-optimisation from being implemented, they can reduce its attractiveness.

- **Definition and measurability.** Some services, such as system strength, are currently difficult to define and to measure, and hence cannot, for the time being, be priced through a spot market in a straightforward manner. However, there may be approaches to at least commit and reward resources that provide these types of services through a structured mechanism. One of these mechanisms (Power System Security Ancillary Services Market) is explored in Section 7E.[105]

- **Locational granularity.** Complete co-optimisation of services that involves consistent pricing in a RT market is highly challenging when the geographical granularity for energy and the service that is being co-optimised with it is different. A core challenge for the procurement of ESS arises in cases where the provision of particular services has different value at different locations, but the RT pricing of the service cannot be made consistent with the (non-locational) energy prices. It is as yet unclear whether the intended goals of ESS designed in this way can be achieved in combination with the current non-locational energy pricing design in the NEM.

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105 It may also be possible to procure synchronous services "by proxy". For example, in GB, NGESO is leading on the development a commercial product where resources are required to provide inertia, fast active dynamic voltage support, and short circuit level (the last component being a proxy for "system strength" as defined in the NEM). This approach is broadly similar to how system strength has recently been tendered for in North Queensland. In its tender document, Powerlinks, the TNSP of Queensland, specified certain technical characteristics that prospective providers would need to meet to address an identified fault level shortfall, but "*new services proposed to provide system strength must be validated through detailed Electromagnetic Transient (EMT) studies*". Source: Powerlink, Request for System Strength Services in Queensland to Address Fault Level Shortfall at Ross, April 2020 (link), page 4.

- **Rare usage.** Co-optimisation with system restoration services seems to be impractical due to the very rare need for using those services and is not explored further in this report. However, we recognise that the system restart services framework in the NEM allows AEMO to define and procure "system restoration support services", such as the provision of voltage control, frequency control and fault current, to support the system restoration / restart pathway.[106] Although these physical services are procured only to be used rarely for system restoration, they could also be used more regularly for other services. The enduring framework for ESS should not preclude such use of services (subject to relevant cost, benefit and risk analyses).

Implications for NEM design

5.18 Lack of co-optimisation among ESS or between ESS and energy may be sub-optimal because it may lead to higher overall costs than are strictly necessary. Some jurisdictions, in particular the US (e.g. NYISO and MISO), have progressively expanded the scope of services that are co-optimised to include frequency (similar to the NEM) and reserves (in contrast to the NEM), following the success of the initial implementation.

5.19 However, the preferred degree of co-optimisation also depends on practical issues such as data availability, software capability and whether the expected value of co-optimisation is likely to exceed the implementation and running costs of the new approach (which is higher for more frequently used services). Overall, the preferred degree of co-optimisation is likely to be driven by:

- Expected costs of implementing the co-optimisation, including developing and maintaining relevant market structures, and software capabilities; and
- Expected benefits of implementing the co-optimisation, and in particular the likely quantum of "inefficiency" from services not being co-optimised (i.e. how far above the global minimum the costs are likely to be in a non-co-optimised market design).

[106] AEMC, National Electricity Amendment (System Restart Services, Standards and Testing) Rule 2020, 2 April 2020 (link), pages 6 and 19.

5.20 Given the prevailing data processing capability, and the local nature of some of the services, it does not seem that a fully co-optimised spot market design, encompassing all system services in the NEM, is likely to emerge in the medium term (e.g. before 2030). As discussed in detail later in Section 7, a number of the system services are not easily amenable to spot market procurement and pricing, which means that they may need to be supplemented by non-spot-market mechanisms (such as regulated provision).

B. Parameter 2: Centralised vs Decentralised Procurement

5.21 The procurement of ESS can take a number of different forms, characterised by different degrees of centralisation, competition among participants and the reliance on “passive” technical requirements. The key options that may be considered include:

- **Market provision**, whereby the service is procured in a decentralised manner, i.e. directly by market participants. In this arrangement, the wholesale market is designed such that there are incentives to encourage buyers and sellers of the service to interact directly (without directions of a central entity) and in a way that incentivises overall system security at lowest cost. An example of this approach is the current provision of FCAS or bulk energy in the NEM.
- **Competitive process**, whereby a central party (usually the system operator) conducts a market-based procurement of a service, typically through a tender process. An example of this approach is the provision of Firm Frequency Response by National Grid ESO in GB, where competitive tenders are run to deliver specific MW targets for different frequency response products.
- **Direct bilateral procurement** of a service, ahead of time, between a central entity and the providers of the service. For example, the central entity (the SO), or TNSPs, can choose whether to enter into a procurement process for a service, and, if so, whether to enter into agreements with specific resources to provide system services, where the price for providing such service is negotiated bilaterally.

- **Regulated procurement** of a service, where the responsibility for maintaining a particular level of service lies with a market participant and the investment required to deliver the service is recovered through a regulated revenue stream. An example of this approach is the provision of inertia and system strength by TNSPs, where the necessary investments are approved by the regulator (AER) and the costs are recovered through network charges on customers.
- **Active mandatory service**, whereby the provision of a service is part of the resource's licence conditions, generator agreement, and/or other relevant regulatory arrangements. The resources are required to actively respond to the central entity's instructions and may be subject to a penalty regime in the event of non-delivery. An example of this approach is the Mandatory Primary Frequency Response, recently introduced in the NEM.
- **Passive mandatory provision**, whereby the service is not directly procured from participants, but where rules are imposed on market participants to operate within certain technical parameters. An example of this approach is the settings of the protection mechanisms on generation assets, which support the system strength.
- **Reliance on ad-hoc interventions**, where a particular service is not procured ex-ante, but instead only delivered by resources when called upon (directed on) by the system operator.

5.22 The provision of a service can also be achieved through a hybrid combination of the different options. For example, in the NEM currently some frequency response services are mandatory, whereas others are procured via markets.

5.23 Among the options described above, one key market design choice is whether any of the services should be provided through regulated solutions. As discussed in Box 5-1 below, there may be circumstances in which a regulated investment (e.g. by a TNSP) or a mandatory requirement approach (e.g. for generators) may be appropriate.

Box 5-1: Non-market provision of ESS

Procurement of ESS from the market (e.g. through spot market, tenders and/or bilateral contracts) may be an attractive approach if the competitive pressure has the potential to reduce the costs of the service. However, there may be circumstances in which alternative approaches are preferred.

Regulated investments (e.g. by TNSPs) may be a more appropriate choice in the following circumstances:

1) **Restricted competition.** Limited competition to provide a particular service (e.g. because the potential pool of providers is limited due to the local nature of the service). However, this could be potentially addressed through competitive forward procurement.
2) **Near-zero energy prices**. Falling energy prices (e.g. due to low marginal cost generation on the system) may make it uneconomic to provide solutions to some requirements in the energy market because of high minimum load costs when energy prices are near zero. This is because the low energy prices are not sufficient to compensate for the minimum load costs involved in bringing online additional resources to provide services (such as inertia or system strength). These requirements may be met by a transmission investment-based solution that must be provided by the transmission provider. This outcome could evolve over time and would be reflected in rising energy market costs to obtain the service in the spot market. These rising spot market prices would provide a cost basis that could be used to evaluate the economics of regulated alternatives.
3) **Technical limitations**. Some technical limitations may mean that the TNSP can help facilitate the provision of a system service.[107] Investments by TNSPs, as opposed to generators, may also allow for some cost savings, if the investment to meet the need for a system service (e.g. system strength and inertia) can simultaneously address other requirements that the TNSP has (e.g. voltage control or reactive power). However, the downside of this approach is that, if faced with a choice between a generation and a network solution, TNSPs are unlikely to make the choice in an unbiased manner.

A minimum technical requirements approach may be a more appropriate choice if the following factors make a market-based approach less attractive:

1) **Cost efficiency.** Some security issues may emerge over time that are addressed at least cost by imposing minimum requirements on all generators, or on new generators. As some US ISOs have already found, it can be cheaper to simply require that every new resource meet specified technical parameters than to do extensive studies to determine which resources do <u>not</u> need to have this capability, especially on a forward-looking basis. This approach is particularly likely to be efficient if the cost of incorporating the required capability in new generation is materially lower than retrofitting generation once it is operation. However, this approach does not come “for free” because it may impose costs on generators that are ultimately recovered from consumers.
2) **Technology risks.** As AEMO accumulates operational experience and the resource mix evolves it may become apparent that some resources are using technologies or features that pose substantial security risks. For example, the use of momentary cessation software in the US was determined to be contributing to large outages of solar generation following even small transmission faults. This same operating experience helped identify a particular solar inverter manufacturer whose software did not correctly measure frequency, similarly resulting in trips following transmission faults.

Implications for NEM design

5.24 Each of the options discussed above involves a trade-off between:

- Costs, which include the setup and operation of the procurement mechanism (both for the SO and the market), as well as the potential delay to the provision of the service (e.g. in terms of the incremental costs of managing the power system in the interim period while the regime is being designed); and
- Benefits in terms of increased security and lower aggregate costs of balancing supply and demand.

5.25 The balance of costs and benefits determines the appropriate approach to be deployed for different ESS. As set out in Section 4, the main principle for procurement of ESS is that excessive complexity should be avoided unless justified by the expected benefits to consumers.

5.26 However, not all services need to be procured through a structured approach. For example, the reliance on ad-hoc AEMO interventions be appropriate in instances where the need for a particular service is (i) highly uncertain and (ii) expected to be infrequent, such that the provision through any of the other approaches above is seen as excessively complex and costly relative to the benefits that consumers would receive from a more structured process. This is discussed in more detail for individual system services in Section 6 and Section 7.

C. Parameter 3: Target setting

5.27 To procure a desired level of a particular system service, it may be necessary to define *ex-ante* an appropriate level (or "target" quantum) of that service. The need to define a specific target depends on other aspects of the market design – for example, there is no need to specify a "central" view of the target for the operating reserves, as this remains a choice for the market participants.

5.28 In cases where a central entity, such as an SO, seeks to procure a specific amount of a service, the targets can be set either as a fixed volume or can vary dynamically.

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[107] One example of this could be the improvement in the provision of system strength. As discussed in ¶2.49 above, a stronger network (with lower impedance) enables the system to "transport" the provision of system strength to a wider area. While transmission investment cannot displace the need for a synchronous machine to act as the source of system strength, it can widen the benefit that the machine conveys to a larger geographical area.

5.29 **A fixed procurement target** specifies a unit (e.g. MW for reserves or GWs for inertia) and a quantum of target that needs to be provided in particular periods. This could be a single annual target applicable for the whole year, or it could be more granular (e.g. different levels depending on time of day, season, etc), but in all cases the target is fixed well in advance of RT. The target could also be based on forward-looking analysis based on the historical projection of variability of RT output.

5.30 This type of target has been the traditional approach. For example, it has been applied to reserves to cover largest contingency, MISO's procurement of ramp capability in RT dispatch, and NGESO's procurement of Short-Term Operating Reserve ("**STOR**").[108]

5.31 Conversely, a more **dynamic target** can be specified, where the quantum is not specified in advance, but rather dynamically adjusts to system conditions. For example, the California Independent System Operator ("**CAISO**") design for setting flexi-ramp procurement targets is continually updated based on recent outcomes (although it is generally considered that the updating process could be improved). The dynamic adjustment can be based on projected future system conditions and may also incorporate a forecast uncertainty measure ("**FUM**") which reflects a probabilistic assessment of future needs. For example, within its review of the SA black system event, AEMC proposed such a mechanism, termed the N-1 (plus) approach. This would "*allow the technical envelope to be dynamically adjusted to account for indistinct events*" based on a probabilistic assessment of risks, which would develop as forecasts evolve.[109]

5.32 A dynamic target is considerably more complex to design and has not yet been widely deployed internationally. For example, CAISO is moving towards a design that ties the target to the projected level of variable resource output and net load. If projected variable resource output is low, less reserves are needed. If projected variable resource output is high, more reserves are needed to mitigate against the larger magnitude of any forecast error. However, this option has not yet been fully implemented by CAISO, so the complexity remains uncertain (and a potential barrier to implementation).

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108 The GB system operator procures min 1,800MW of STOR, with a target of 2,300MW where economic. The optimal level is managed daily through a week-ahead Flexible STOR assessment in response to the forecast conditions for the week-ahead. Source: NGESO, STOR Market Information Report, 22 March 2019 (link), page 2.

109 AEMC, Mechanisms to Enhance Resilience in the Power System – Review of the South Australian Black System Event, 12 December 2019 (link), page 126.

5.33 In addition to the quantum of the target, the scope of the target may also vary, depending on the objectives that the SO is seeking to achieve:

- A **minimum target** (which may or may not be fixed) can be specified to reflect the need for services to maintain a baseline level of system stability. In specifying this target, the SO implicitly considers that system services provide value by enabling the system to remain stable, but there is no additional benefit from additional services.
- An **above-minimum target** can be specified that reflects the benefits of incremental service provision above the minimum levels required to maintain system stability. This can be expressed as a willingness to pay for higher levels of service (potentially through declining prices), i.e. a "demand curve" (see Section 6 for more detail on this concept). For example, there might be benefits of procuring higher-than-minimum levels of system strength or inertia in delivering greater resilience of the system (e.g. ability to respond to multiple and/or less credible contingencies), or in delivering higher volumes of VRE output.

5.34 Both approaches allow a more explicit valuation of services that are currently provided but not remunerated, and also allow a more explicit valuation of services that could be provided (either in operational or investment timeframes) if there was an economic incentive to do so.

D. Parameter 4: Geographical Granularity

5.35 System services can be procured over different geographic footprints, ranging from NEM-wide procurement, to state-wide procurement and more locational procurement (sub-state level, or potentially even node-level).

5.36 The appropriate choice of geographical granularity will be driven by operational considerations of the nature of the service and the transmission constraints that may limit access to resources that provide a particular service:

- **Locational procurement.** Services that deliver primarily local benefits (e.g. system strength or voltage support) may need to be procured on a relatively more locational basis. In addition, when there is congestion on the transmission network, it will be essential to ensure that ESS can be dispatched in RT (i.e. resources are not located behind transmission constraints). NEM-wide procurement would tend to naturally result in some reserves being scheduled behind transmission constraints so some kind of locational requirements would be necessary.

- **NEM-wide or regional procurement.** Not all ESS need to be procured on a locational basis. Services that deliver NEM-wide benefits (i.e. are location-independent, such as, to a large extent, inertia or frequency response) can be procured NEM-wide. However, it may also be appropriate to consider partial approaches, where a portion of the service is procured NEM-wide, but another portion is procured locally on a more regional basis. An example of this arrangement could be inertia, where, for most part, the service can be procured NEM-wide, but a contingency for the risk of islanding of some states (e.g. SA) may require some local procurement as well.

5.37 The appropriate choice of geographical granularity will also be driven by the wider market design in the NEM. In particular, if it is considered preferable to co-optimise services, it is likely to be necessary to align the geographical granularity between those services to ensure that the price signals are consistent. This would imply that:

- Those ESS that can be procured on a regional basis could also in principle be co-optimised with energy and FCAS (as these are also regional); and
- For those ESS that require more locational procurement, it would be more challenging to achieve co-optimisation of the locational service prices with non-locational energy prices (i.e. set at the Regional Reference Node).

E. Parameter 5: Procurement timeframe/resource commitment

5.38 System services can be procured and scheduled over different timeframes. Existing resources can be scheduled in RT, on an intraday basis or may require an ahead time commitment. New resources may need to be procured ahead of time, potentially by several years, depending on the investment lead time required.

- **RT or intraday** procurement would likely attract long-starting resources based on expected prices (ahead of time). Intra-day supply, in response to changing system conditions, would be elicited from resources that do not require significant advance notice to start-up and synchronise with the network.
- **Day-ahead** procurement may attract resources that require a longer notice and must make a commitment in advance to be able to respond in RT. For example, demand response may require such notice in order to reduce load safely upon instruction, or generators may require such notice to start within particular timeframes.

5.39 A key consideration is how ESS can be procured efficiently not just for a single service, but across all services and across time periods. Some services may benefit more from ahead-commitment than others, and this may impact whether and how co-optimisation among ESS may be achieved.[110]

5.40 In latter sections of this report we consider in more detail options for the procurement of ESS, and we find that a design based on the concept of "demand curves" (presented in Section 6) could be implemented both:

- within the framework of the current NEM self-commitment approach, based RT market; or
- within the framework of a centrally coordinated LMP-based ahead-market for energy, FCAS and other system services.[111]

5.41 In terms of an ahead market for ESS, it appears that:

- An ahead market for ESS, based on the concept of demand curves, could readily be combined with a subsequent reliability evaluation by AEMO that uses a form of ahead time design that supports additional commitments of resources by AEMO (this is discussed in Section 7E on PSSAS); and
- An ahead market-based on commitments made by AEMO (see Section 7E on PSSAS design) might also be implemented, although this is less certain and would need to be informed by discussions with vendors. We expect the PSSAS design could be applied within an ahead market in which almost all of the resources needed to meet synchronous services needs were self-committed in the ahead market. However, the quality of market solutions is less certain if the ahead market needed to optimise the commitment of a number of resources by optimising over perhaps dozens of different solutions based on different combinations of resources (like those expressed in the TLA tables, as displayed in Box 2-1 in Section 2).

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110 The resource commitment is closely related to wider aspects of NEM market design, and in particular the potential changes, currently under discussion, of ahead-market designs. Source: ESB, System Services and Ahead Markets, April 2020 (link).

111 The procurement of energy, reserves and FCAS in forward LMP-based markets utilising demand curves for reserves and FCAS was successfully implemented 15 years ago in North America (NYISO). Since that time the basic ahead market framework has been implemented in many additional ISO markets and the role of reserve demand curves has been refined and extended.

6. Framework for procuring and scheduling ESS

6.1 Potential models for procuring and scheduling ESS are defined through a series of high-level dimensions (e.g. degree of co-optimisation, geographical granularity) and specific parameters (e.g. quantitative targets for procurement, eligibility criteria for providers). Both the dimensions and the specific parameters are defined on a spectrum of options, from which policy makers may choose the preferred design.

6.2 From a policy maker perspective, it may be not be appropriate to apply the same dimensions and parameters to all system services, nor to select a single approach on this spectrum as the “target model” for all system services. This is because there are trade-offs between different ways of procuring and scheduling system services: for example, increasing the efficiency of procurement may require the development of new markets, but this would also increase the complexity of the design (which may or may not be proportionate relative to the expected increase in efficiency). For other services, simplicity and transparency may be more important than a very accurate cost recovery “causer-pays” mechanism in order to obtain stakeholder buy-in to the process.

6.3 Policy makers may therefore prefer to procure and schedule different ESS in ways that are most suitable to the relevant circumstances, the physical characteristics of each service and the quantum required. Additionally, the optimal choices for individual system services are likely to change over time, as the NEM system evolves. For example, an ad-hoc approach to procurement and scheduling based on AEMO directions may be a reasonable approach in some regions and for some ESS. However, as the system progresses towards a VRE/IBR-dominated world, the need for synchronous system services (such as inertia and system strength) may increase, such that a more structured approach may provide better outcomes for consumers. In general, such changes in the design choices are likely to be driven by the supply mix (e.g. VRE/IBR penetration), technological progress (e.g. development of technologies that can provide synchronous services without injecting energy), or regulatory conditions (e.g. the wider regulatory framework and obligations).

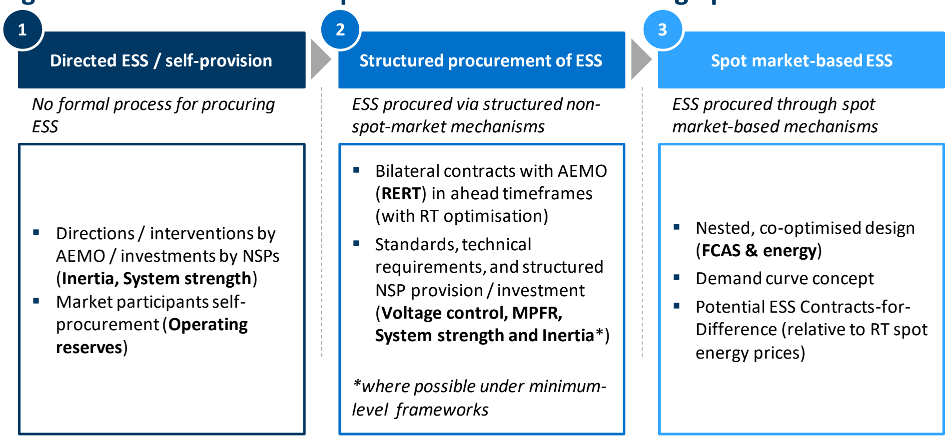
6.4 This section therefore combines the specific model variants from the previous section into a "**Framework for procuring and scheduling ESS**". The objective of this framework is to provide a **menu of options (rather than a single option)** for procuring and scheduling ESS. This approach enables policy makers to select design choices that are specific to each service, recognising that current procurement and scheduling approach for services differ and therefore will evolve from different starting points. Choices can also be adjusted over time as and when appropriate given the wider market, technological and regulatory conditions.

6.5 In this section, we provide an overview of the **options** for procuring and scheduling ESS, which range from adjustments to the current NEM design through to the concept of "demand curves" (Section A). We then elaborate in more detail on the concept of demand curves (Section B) and also provide an example of how demand curves are developed in practice (Section C). We apply this framework later in the report (Section 7) to consider potential pathways for evolving the procurement and scheduling of individual essential system services in detail.

A. Options for procuring and scheduling ESS

6.6 As set out in Section 3, the current NEM approach to the procurement and scheduling of ESS may not be suitable to meet the future needs of the system. To improve the approach, policy makers may consider various degrees of change, ranging from less complex adjustments to the current design (labelled "NEM Evolve"), through to more complex changes that may involve an explicit procurement of services through spot market or non-spot-market routes. An overview of these high-level options is provided below in Figure 6-1.

Figure 6-1: Overview of ESS procurement and scheduling options



The spectrum of procurement options for ESS, with identification of current provision mechanisms in bold. Source: FTI analysis

6.7 The “menu” of ESS procurement and scheduling approaches set out in Figure 6-1 above encompasses a wide range of specific design options, and is summarised in the following paragraphs.

6.8 In **Option 1 (Directed ESS / Self-provision)**, there is no formal or structured process for procuring or scheduling system services. This option reflects the current NEM arrangements for a number of services (namely inertia, system strength, operating reserves and voltage control). The need for these services is met primarily through ad-hoc (and often reactive) intervention by AEMO or NSPs when the energy market fails to provide one or more of the services in sufficient quantities as a consequence of the prevailing energy market incentives. As set out in Section 2, the provision of operating reserves is decentralised and a side consequence of the energy market decisions of individual wholesale market participants.

6.9 Moving from Option 1 to **Option 2 (structured procurement of ESS)** would (for some services) represent a **NEM Evolution** that would formalise the procurement and scheduling of ESS through structured (non-spot-market) mechanisms. The three main examples of such mechanisms are (i) bilateral contracts between resources and AEMO; (ii) requirements imposed on TNSPs to maintain certain network standards (and address shortfalls through investments and/or contracting); or (iii) the implicit outcomes of technical and performance standards imposed on resources. The bilateral contracts and the TNSP investments would typically be contracted for and undertaken ahead time. In addition, there may be spot markets for the individual services. Importantly, as we explore in Box 6-1 below, forward contracting will be highly challenging (and may even be unworkable) for resources providing synchronous services (e.g. inertia, system strength), particularly if there is no spot market to settle deviations between their forward contract obligations and their RT performance.[112]

6.10 Elements of this option are already in use in the current NEM design: for example, TNSPs may invest in synchronous condensers in order to mitigate shortfalls in inertia and/or system strength when a shortfall is identified by AEMO (and subject to a regulatory approval through a RIT-T process). In Option 2, however, these procurement and scheduling mechanisms would be formalised into more structured commercial processes that would deliver greater system security, but would fall short of spot market style procurement.

[112] In addition, we discuss in Section 7 that a forward contracting process for system strength requires that AEMO be able to define and measure what different resources are providing; otherwise it is not clear how AEMO or NSPs would decide on the appropriate remuneration for the service, via a forward contract.

6.11 There is a key trade-off between procuring of services through regulated investments by NSPs and through a market mechanism, as summarised in Table 6-1 below.

Table 6-1: Regulated vs market-based procurement of system services

NSP regulated investment	Market-based investment
✓ Facilitates investment in assets that are perceived to be too risky in terms of future revenues (i.e. where market-based investment would price-in an excessive risk premium to the detriment of consumers). × The risk of excessive investment is placed with network users (and only mitigated through RIT-T type test). × Risks crowding out market-based investment if resources perceive a risk that a regulated investment can underbid market-based resources because of a cost advantage due to the regulated nature of the asset. × Risks increasing consumer costs if AEMO identification of a service shortfall is "too late" (e.g. if service already needed, or if construction lead times are long).	✓ Allocates the risk of excessive and inefficient investment to the owner of the asset (rather than consumers) ✓ Encourages competition and innovation in delivery of system services (e.g. reduction in minimum load blocks or innovation to provide inertia without injecting energy), which would drive a long-term reduction of costs. ✓ Allows TNSP investments to be evaluated against the market prices. × May not attract investors if market-based prices are perceived to be too volatile and unpredictable (e.g. reliant on infrequent spikes) to support long-term investments (or may lead to investors pricing in the risk premium).

Source: FTI analysis

6.12 Table 6-1 above indicates that market-based investments have several advantages over regulated investments, but they might not always be preferable to a regulated investment. There may be circumstances where investment signals for resources to provide specific services may not be sufficiently strong to trigger adequate investment (e.g. if the prices are volatile and unpredictable, or if the prices are too sensitive to small surpluses in the supply of a particular service). We explore in Section 7 whether this might be the case for synchronous services such as inertia and system strength. If and when this challenge arises, this may need to be taken into account in the overall design of ESS (as well as the regulatory regime, as discussed in Section 8).

6.13 In addition to the regulated investments and forward contracting, AEMC may set and adjust technical standards applicable to new or existing resources to mandate the provision of some services (or at least the ability to provide them). For example, in 2018 AEMC introduced significant changes to the technical performance standards for generators, in order to improve the security of the power system in response to challenges associated with the energy transition.[113]

6.14 Option 2 could also involve AEMO and/or TNSPs considering more explicitly (and perhaps more formally) the contribution of particular resources towards multiple system services simultaneously. For example, in deciding whether to invest in new synchronous condensers or continue to dispatch a particular synchronous generator in order to increase system inertia, the relevant decision maker could also consider the contribution of each resource to other services (e.g. system strength). Such considerations would aim to better approximate a "co-optimisation" of ESS and, in so doing, aim to reduce the overall costs to consumers.

6.15 A key feature of this option is that it does not require the development of any new multilateral spot markets for delivering ESS. Instead, it relies on rules being in place that drive relevant parties (AEMO, NSPs or resources) to take investment or operational actions that either improve the delivery of specific ESS or strengthen the system's resilience to ESS shortfalls.

6.16 There is also a sub-variant of Option 2, where system services are procured through forward contracting (e.g. bilaterally with AEMO or NSPs), but co-optimised in RT. This is discussed in Box 6-1 below.

Box 6-1: Forward contracting without a spot market-based ESS

There is a potential "mixed" variant in which system services are procured on a forward basis (e.g. months, years) through structured arrangements[114] (e.g. bilateral contracts with AEMO or TNPSs), and the supply of these services is subsequently co-optimised with the supply of energy in RT operations. This variant could either be implemented in combination with a RT spot market (and price) for the services or without a RT spot market (or price). Both of these options are explored below in turn.

113 AEMC, National Electricity Amendment (Generator Technical Performance Standards) Rule 2018, 27 September 2018 (link).

114 There is a difference between out-of-market mechanisms such as RERT and system service contracts such as bilateral contracts with AEMO or NSPs, which may be framed as market mechanisms.

If the variant is implemented in combination with a RT spot market (separately for each ESS), then there would be a potential for market participants to settle deviations between their forward contract obligations and their RT performance at this spot price, but this would require developing a RT spot market (see Option 3, discussed below).

If this variant were implemented without a RT spot market, this would avoid the challenges associated with developing a spot-market-based procurement of services (Option 3, discussed further below), but the lack of a market for financially settling deviations would require a design based on physical performance. Such a design would have the potential to deter all but a few firms from participation[115] in the forward market because only resources who expected their operation to be economic in the energy market almost all the time, and hence be online and able to provide the services, could be confident of covering the physical performance requirement without the risk of incurring large energy market losses.[116]

An additional complication is that running separate procurements for individual system services, each of which would be provided by online resources might further magnify the risk of bidding for such contracts, with the potential for winning contracts for some system services and not for others. This could be addressed by developing a joint procurement design across a range of system services, but this would be complex.

In our view, such an approach relies on very strong assumptions regarding the nature of the non-spot-market contractual arrangements: it assumes that resources will be willing to commit well ahead of RT to being available for dispatch continuously (or at very specific times, or at very short notice – e.g. at 8.55am on 15 January 2025).[117] While this may be true for some resources (e.g. those who have a high degree of confidence that they will be economic given the prevailing energy market conditions at that time), other resources are unlikely to be able to enter into such forward commitments, or may only be able to bid very high prices for the system service to reflect the risk that they may not be online (injecting energy) at the time they might be called upon to deliver the service. This is particularly the case for system services that are typically provided jointly with energy (i.e. resources must be online in order to provide the system services).

115 Conversely, the contracts could have a “make-whole” clause such that resources would be compensated for providing the services if the energy price is low (or even negative). In this case, such clauses may deter AEMO / NSPs from entering into such contracts.

116 Even with a spot market, it is uncertain how willing resource operators will be to enter into long-term contracts that would require that they participate in the energy market in order to provide the specified services, given the potential for continuing declines in spot energy prices.

117 An alternative possibility would be for AEMO to centrally commit to these types of contracts ahead of time, if sufficiently confident that the system services might be needed. This is explored in Section 7E on the PSSAS.

This sub-variant could lead to a very illiquid forward market with competition limited to a subset of potential resources that can pre-commit on a long-term basis, or it would lead to very high market clearing prices in the forward procurement (or both). As a result, only that subset of resources would in fact face a clear price signal.

This design would have elements that are similar to designs which have previously been used in the CAISO day-ahead markets (1998-2000) and in the ISO NE forward reserve market, where similar market design attempts have failed.

The separate forward procurement of energy and ancillary services in the original CAISO market design led to extremely bad market outcomes during uncertain market conditions, because of the risks of offering to provide ancillary services from thermal resources, without knowing if the resources would be economic in the energy markets. This market had other elements that contributed to the adverse outcomes, such as the independent procurement of ancillary services for each hour, but we do not think the performance of this design is encouraging for a design based on long-term forward procurement of system services by AEMO.

The ISO NE forward reserve market found that the only suppliers willing to participate in the market were those that could provide the services from offline resources. ISO NE has made multiple rounds of changes to try to fix these problems while the independent market monitor has for years recommended eliminating it.

For these reasons, we consider that this subvariant of Option 2 is unattractive and we do not examine it further in this section.

Source: FTI analysis

6.17 Finally, moving to **Option 3 (Spot-market-based ESS)** would, for most services, require a more fundamental market design change that would explicitly articulate the quantum and type of need for relevant services (as is already the case for FCAS). This could be in the form of minimum technical requirements (i.e. a single figure, such as a set MW target) to maintain baseline levels of system security[118] or a more complex trade-off between price and quantity of a specific service. In some cases, the **design change** could be informed by precedent from international jurisdictions, but in other cases the system service design change would be genuinely **innovative**.

[118] Another option could be to set the short-circuit current ratios at relevant nodes for system strength.

6.18 This option uses the concept of spot market “demand curves” to express the demand for specific ESS, which can then be met through supply from (potentially) a wide range of resources. However, the complexity of such demand curves can vary significantly: at the simplest level, the demand curve can express the willingness to pay a positive amount for a certain minimum level of service (for example, X MW of reserve in region Y, or Z GWs inertia across the NEM) but zero above that. At the other end of the spectrum, more complex demand curves could reflect the willingness to pay for services above the minimum level (at a progressively lower price as the quantum of the service increases), vary by region, and could also be interrelated (or “nested”) across different ESS.[119] We return to the concept of demand curves in more detail in Section B.

6.19 This option can also be combined with forward contracting of services using a contract for difference (“**CFD**”) mechanism, in which resources that are committed for a system service receive an additional payment equal to the difference between a (pre-agreed) strike price and the energy price. This CFD mechanism would thus provide a make-whole payment if the energy spot price was lower than the price at which the resource was willing to provide the system service.

6.20 Crucially, this option requires the decision maker to be able to observe and measure the provision of the service, as well as define a willingness to pay for different quantities of the service. While this may seem obvious, this is not currently feasible for all the ESS considered in this report. For some services, including operating reserves, there is extensive international precedent for developing demand curves, and learnings that can be applied to inertia, but this is not the case for, say, system strength or voltage support.

6.21 Overall, the proposed range of options can serve as a guide for mapping out and implementing potential changes to the procurement and scheduling of individual ESS. It encompasses a wide range of specific design choices, and embeds a degree of flexibility for policy makers, which means it can be compatible with evolving policy design preferences as well as market and technological conditions.

[119] The specific parameters that might be set for the demand curves encompass a full spectrum of design options. They can also be adjusted over time such that the overall framework remains stable, but the specificities of the NEM market design could evolve to proportionately and efficiently meet the needs of consumers on a long-term basis.

6.22 It is worth emphasising that there may not be a single procurement and scheduling option that suits all ESS at all times. Rather, the ESS arrangements may need to be tailored to individual services, and potentially evolve over time as circumstances change. For example, not all system needs can currently be met through a market-based solution, such as a demand curve-based tender. Rather, as shown in the range of options above, the procurement of ESS needs to be proportionate to the relevant needs and appropriate for the characteristics of the service. In some cases, it may be more efficient to procure a regulated solution (such as TNSPs' investment in synchronous condensers) or mandate a more stringent technical standard.[120]

6.23 In the following subsection, we explore the concept of demand curves for ESS in more detail.

B. Concept of demand curves

6.24 The main concept behind the spot-market-based ESS option (Option 3 in the Figure 6-1) is that the need for different ESS is expressed through "demand curves". These curves display the willingness of the market operator to pay (on behalf of consumers) for services that are required to deliver system security. By defining the demand for each service, the concept aims to ensure that the system operator does not pay for more of a service than is needed (i.e. in excess of the pre-defined demand).

6.25 In the following subsections, we first introduce the basic concept of demand curves and how prices are formed through the interaction of supply and demand. We then set out how demand curves can provide investment and operational price signals. Another two subsections explore in detail the different types of demand curves and how their shape can be determined. We also explain that the concept of demand curves is compatible both with a range of wider market design options (e.g. centralised and decentralised approaches, and ahead-markets). Finally, we set out some of the challenges associated with operationalising the concept of demand curves.

120 The cost visibility provided by the demand curve for each product in each location would aid evaluating the cost effectiveness of potential regulated solutions relative to the market-based solution identified under this process.

Basic demand curves

6.26 At its heart, the concept of a “demand curve” expresses the relationship between the RT price and the quantity of a service from the perspective of the buyer of the service. It defines a range of prices from high prices (i.e. a high willingness to pay for the service if only a small supply is available) to low prices as the supply rises above the minimum needs (and the corresponding willingness to pay is reduced). The key element of demand curves is that they do not simply set an arbitrarily high price for acquiring a minimum quantity of the service but set a price that would set market prices as the supply of the services falls below the target level. By defining a demand curve with appropriate convexity, traditional optimisation methods can be employed to determine the least cost dispatch. Demand curves can also be utilised in centrally-optimised unit commitment decisions, using modern solution methods including mixed integer programming.

6.27 Some elements of this concept are already implicitly used in the NEM:[121] for example, the procurement target is implicitly set by AEMO (e.g. in identifying shortfalls of a service), but the current approach does not seek to articulate a price for mitigating that shortfall. Rather, when AEMO intervenes to bring resources online to mitigate shortfalls of a particular service (say, inertia), it is expressing a willingness to impose costs on the system to deliver a particular quantum the service (i.e. the volume that is directed to come online). The current approach does not represent a “demand curve” because it does not define any explicit prices.

6.28 In contrast to the current NEM arrangements, a demand curve explicitly conceptualises the relationship between quantity and prices. The simplest demand curve for a service can be expressed as a willingness to pay a fixed maximum amount (“cap”) to obtain the service, but no more. This is illustrated in Figure 6-2 below.[122]

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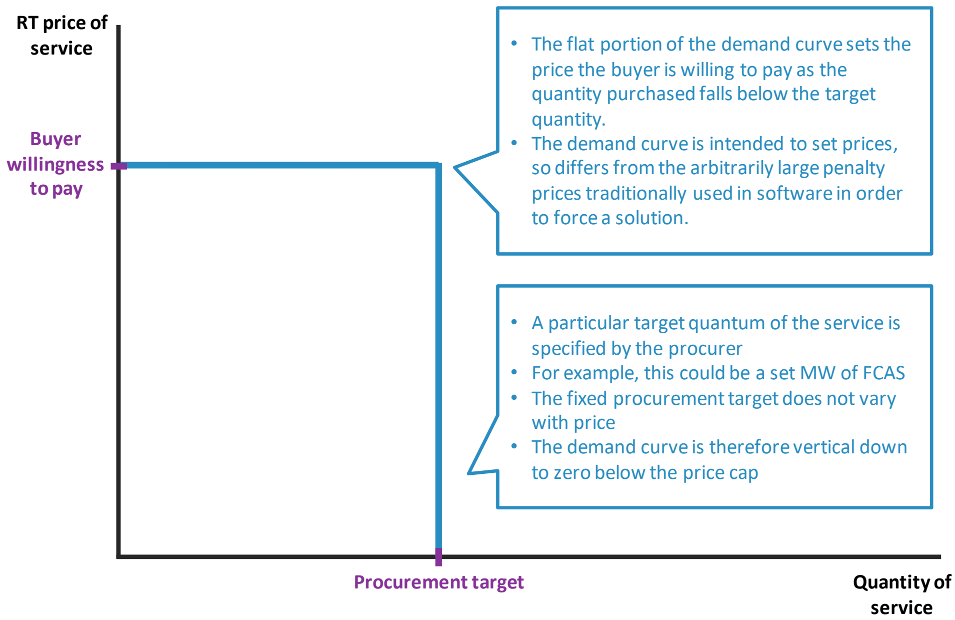
121 Some elements of these concepts are also being implemented in the WEM for the procurement of Minimum RoCoF Control Service and Additional RoCoF Control Service. Energy Transformation Implementation Unit, Transformation Design and Operation Working Group Meeting 11, 29 April 2020 (link).

122 The demand curve has some parallels to the current procurement of FCAS in the NEM: the vertical portion of the curve represents the minimum levels of FCAS that are procured by AEMO.

Figure 6-2 : Illustration of a simple demand curve



Source: FTI analysis

6.29 This type of demand curve is not very effective in sending price signals because while it sets a high price when the supply falls below the target, the price would fall to the incremental supply offer if the supply offered exceeds the target by even a small amount of service provided, as illustrated in Figure 6-3A below.[123]

6.30 These large price discontinuities in the very simple ("vertical") demand curve risk not sending an effective price signal for self-commitment decision, as market participants might find it highly risky to rely on price outcomes that would be unstable (and likely to collapse in response to very marginal changes in supply). Alternatively, if markets utilised some type of centralised commitment process to bring resources online, this could result in potentially large uplift costs paid to providers of services, as resource commitments would be economic based on the penalty price for avoiding shortfalls, but would be uneconomic when the commitment of the resource eliminated the shortage.

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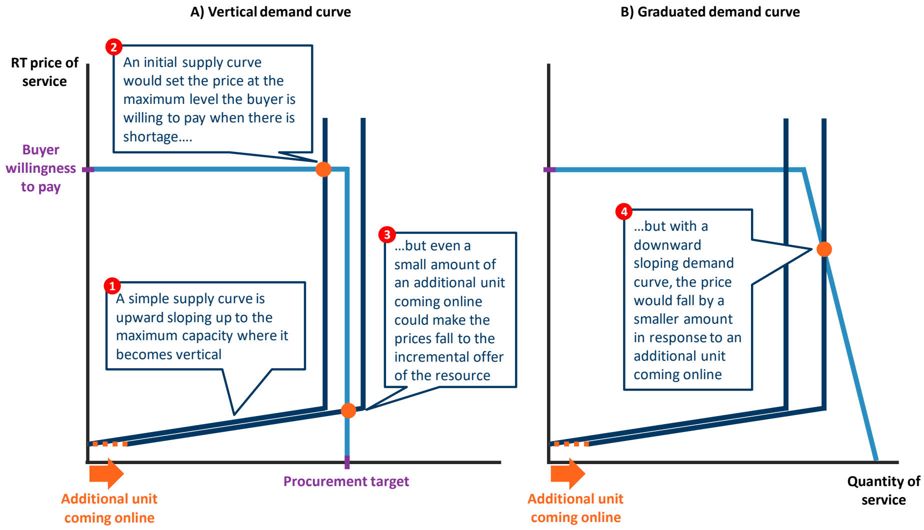
123 This could be MW, or MWs or other relevant units specific to the system service.

6.31 Demand curves that are workable within the current NEM self-commitment design (i.e. resources self-commit rather than wait to be ordered-on by AEMO) would require that all resources providing the service are paid the clearing price as set by the intersection of the demand and supply curves. In order to send an effective price signal for self-commitment decisions, a demand curve would need to set different penalty prices for different levels of supply shortfall.[124]

6.32 A comparison between a “vertical” demand curve and a more graduated one is shown in Figure 6-3A and Figure 6-3B below. In the left panel, a vertical demand curve creates a risk that an additional unit coming online leads to a large price fall (from the maximum willingness to pay, i.e. the horizontal portion of the curve, to the marginal resource’s incremental offer). In the right panel, a graduated demand curve reduces the magnitude of the price impact that a given unit coming online might have.

Figure 6-3: Impact of simple and graduated demand curves on clearing prices



Source: FTI analysis

124 The ORDC used in the energy market by ERCOT provides the polar case of a sloped demand curve that can set a different price for each level of shortage in the market.

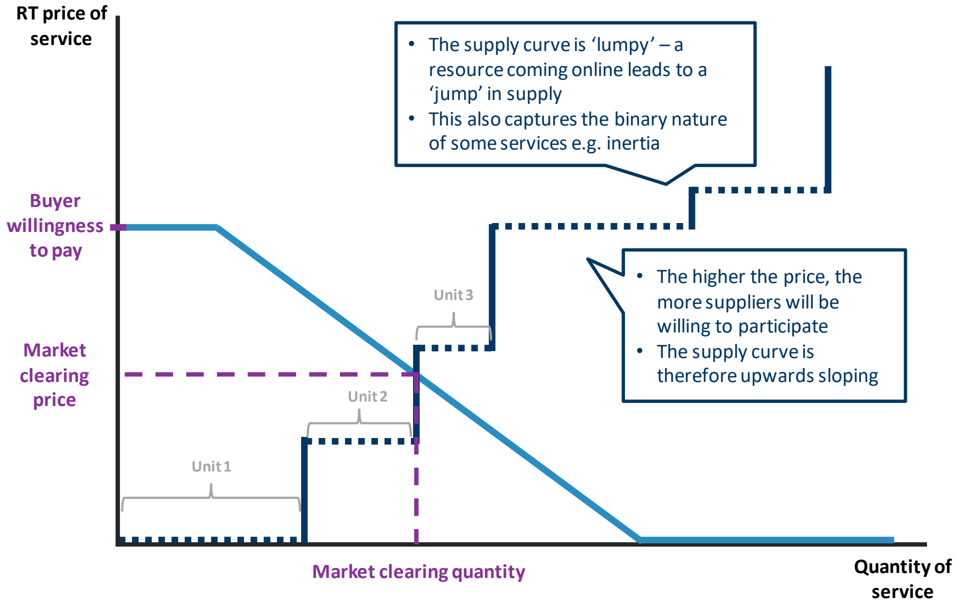
Price formation in RT

6.33 The RT price (compensation) for a service is identified in every settlement period as the intersection of the demand curve with the supply curve (i.e. the market equilibrium point), as illustrated in Figure 6-4 below. Resources that provide the service are compensated through the market clearing price identified by that intersection.

6.34 As demand curves can be defined for multiple services, resources may receive multiple streams of revenues: bulk energy revenues, revenues for a spot-market-based ESS based on demand curves, as well as revenues for non-market services.

6.35 The examples above (¶6.28 to ¶6.32) portrayed services with offer prices for incremental supply, so that the demand curve only set prices when there was a shortage, with prices otherwise being set by offer prices. The demand curve concept can also be used to set prices for services that are either not offered or are offered at zero cost (for example, inertia can be offered by online resources at zero marginal cost, as the resource is already operating). This supply relationship would be applicable to the supply of inertia, which either would not be provided if the resource was offline or would be provided at zero incremental cost if the resource was already online. This is illustrated in Figure 6-4 below. For Unit 1 and Unit 2, the buyer of the service is willing to pay prices that exceed the levels at which the seller is willing to provide the service. Unit 3 is, however, non-economic: the buyer would only be willing to pay a price that lies below the market clearing price (shown in purple), at which Unit 3 is unwilling to provide the service.

Figure 6-4: Illustration of RT price formation with supply and demand curves



Source: FTI analysis

6.36 The application of the demand curve concept to inertia is explored further below in Section 7C.2 below. At this stage, it is important to highlight that there is precedent for applying the concept of demand curves to services that have a zero incremental cost (such as services that are provided by synchronous units simply by those units being online), which can be drawn upon in the NEM. We will discuss this further in relation to inertia and system strength in the later sections.

Investment and operational signals

6.37 The RT price for the provision of services varies depending on the relevant system conditions: the price increases as the available supply of the service falls towards the minimum considered necessary, and conversely the price falls to zero when there is a large surplus of a particular service.[125]

6.38 The RT prices (i.e. the cost of meeting demand) would be observed by all market participants and relevant authorities, and would provide a transparent signal for the retention of resources that are able to provide these services at lowest cost to consumers, meeting the resource adequacy and/or security objectives. As such, the prices would provide both a RT operational price signal and a longer-term investment signal.

125 Arguably, this was historically the case for inertia, as the vast majority of generation was from synchronous generation, so the value of any additional inertia was nil.

6.39 In operational terms, the demand curves for each service would enable AEMO to send a strong RT price signal for resources to be online when the supply of a system service is close to the minimum required for secure system operation, while setting a low price when supply is abundant (meaning there is little value provided by additional supply of that service).

6.40 In investment terms, the observability of the different RT prices could provide signals for investment (or retirement) decisions: when the prices are sufficiently high, this indicates that there may be a need for additional provision of the service. However, the prices could also provide signals for other decisions, such as whether a generator invests to be able to operate in synchronous condenser mode or for the development of new technologies able to synchronise to the system without injecting energy.

Types of demand curves

6.41 The demand for a particular system service could be articulated through **one or more demand curves**, at an appropriate geographical or technical granularity. For example, demand for some services may vary by NEM region, or even more locally in cases where a minimum level of service needs to be procured for a specific area. For some services an aggregate NEM-wide demand curve could be met through supply from multiple regions (some or all).

6.42 From a technical perspective, there may be multiple demand curves for different sub-types of a particular service (e.g. for 10-minute reserves and 30-minute reserves). This would be driven by the SO's requirement to express the need for a service at the appropriate level of detail.

6.43 There may also be different minimum technical requirement targets for different times of day. In this case the slope of the demand curve would remain the same and the level of the horizontal line would also remain the same, but the entire curve could shift left-or-right along the x-axis, based on time of day or in response to changes in market conditions. In this sense the basic shape of the curve would be "fixed" ex-ante and only changed infrequently, subject to an appropriate governance process (see ¶6.45), and market participants would understand ex-ante how the demand curve shifts over the course of the day and/or in response to system conditions. For example, CAISO seeks to adjust the demand curve for its ramp capability target from day to day and hour to hour depending on the expected need for ramp capability.

6.44 The demand curves for some services could be the same in the ahead and RT markets, while others might be adjusted between the ahead market and RT based on changes in system conditions. For example, many US ISOs use the same demand curve for operating reserves between the day-ahead and RT markets. Similarly, the MISO uses the same demand curve for ramp capability in its day-ahead and RT markets. The CAISO on the other hand is evolving towards a design in which the demand curve for ramp capability has the same shape in its day-ahead and RT markets but the demand curve would be shifted in or out to reflect changes in expected conditions.

6.45 The demand curves do not need to be fixed. Rather, they may shift over time in response to market evolution and system conditions. For example, if the SO becomes comfortable operating at lower levels of inertia (e.g. levels that are currently technically uncharted), the SO may be willing to pay less for inertia services *at any level of service provided* than was initially the case. The entire demand curve would therefore shift to the left. However, the approach to setting the demand curves would require a robust governance, as would the process for changes to the specific parameters of the framework, particularly if the system is operating in uncharted technical territory. The trade-off between the flexibility and stability of the regulatory regime is discussed in Section 8.

6.46 As an initial step, the demand curves could be defined relatively conservatively, with appropriate safety margins to account for uncertainty (i.e. procuring or scheduling more than what may be considered to be optimal in the longer run), and limited to a subset of the full list of ESS. Going forward, the demand curves could be gradually modified to procure less of a service as the SO gains operating experience; or to procure more of a service as, say, the penetration of VRE grows. The demand curves could also be re-specified to include new services, if the need for new services becomes apparent.[126]

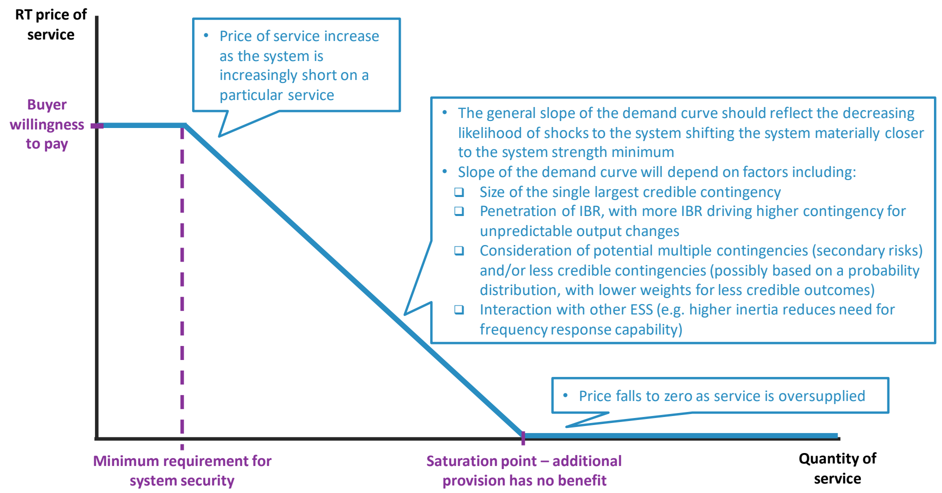
[126] For example, the demand curves could be refined when there are technological improvements that enable previously unmeasurable services to be measured (e.g. system strength). In theory, it may also be possible to extend this framework to encompass distribution-level system services. However, the extent to which this is practically feasible would depend on the services and distribution system involved. This is likely to be challenging, due to important differences in which the true distribution system is operated relative to the looped transmission system, for example. Because of such complications, efforts to extend the methods used to coordinate use of the transmission system to the distribution system are moving slowly.

Shape of demand curves

6.47 A demand curve expresses the price that the SO is willing to pay, on behalf of market participants, for the provision of a particular service. The units of each demand curve (x-axis) would be specific to the service and would be the units in which the SO is able to express the need.

6.48 For a given service, the demand curve can be defined through several key parameters: the minimum requirements, the maximum willingness to pay for the service, the slope of the curve and the saturation point.[127] This is illustrated in Figure 6-5 and detailed further below.

Figure 6-5: Illustration of a more complex demand curve for ESS



Source: FTI analysis

6.49 **Minimum requirements for system security.** As the level of the service approaches the minimum requirements, the demand curve reaches its highest point (likely capped), reflecting the system approaching a near-collapse situation. The cap of the demand curve is likely to be driven by the willingness to pay to avoid the outcome that below-minimum provision of a particular service could lead to, and it is likely to vary by ESS. For example, a shortfall of inertia or system strength is more likely to result in a significant cascading failure than a shortfall in reserves that could be met through localised load shedding.

[127] Policy makers may also consider that there is no need for any saturation point. This could be the case if any volume of the service is seen as – at least somewhat – beneficial for the overall system resilience.

6.50 **The saturation point of the system service.** Beyond this level of provision, there is no incremental value of additional service being provided to improve system security, so the price of the service would collapse to a low or zero level.[128] The saturation point may be close to the left (i.e. close to the minimum requirements) or, conversely, further out to the right. The latter would imply that the system operator values the benefit that a higher volume of system services would bring in terms of the increased number of non-credible contingencies that the system operator can recover from.

6.51 **The slope of the demand curve.** The shape of the demand curve between the minimum requirement and the saturation point is likely to be the most complex parameter of the demand curve to determine. At a high level, it could be (i) a straight line with a constant slope; (ii) piece-wise linear function with different slopes in different ranges; or (iii) a step function with procurement targets at specified price levels. This would be guided by:

- The **cost of the out-of-market actions** that system operators would take to maintain that level of the system service (i.e. the next-best alternative action that would be taken by AEMO). For example, the demand curve could reflect the willingness to pay for the benefit of being able to relax the minimum constraints (e.g. the need to maintain at least two synchronous units online at any given point in time) that might otherwise apply to synchronous generation.
- The benefits in terms of the value of **increased IBR output**. This could be relevant where higher levels of IBR create a greater potential for instabilities from inverter interactions and therefore require greater levels of system strength. Additionally, higher levels of IBR require a higher contingency to cover for unexpected net load changes. In this sense, the slope of the demand curve would reflect the additional quantum of service required to enable more IBR generation, i.e. the willingness to pay for the benefit that the system would be able to support higher levels of IBR penetration.

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128 The price would fall to zero if the provision of the system service beyond a certain level was not remunerated. Alternatively, the lowest price may remain above zero if all resources that are providing a service are remunerated at that price level.

- The **resilience benefits** of having more than the minimum quantity of reserves required to serve load without load shedding, as well as to meet reliability targets. This could include several different factors, including the willingness to pay for services to cover multiple credible contingencies – for example, contingencies that occur in quick succession without allowing sufficient time for the system to recover, or contingencies combined with significant net load forecast errors.[129] There is precedent for including resilience benefits in the design of an operating reserve demand curve ("**ORDC**") (e.g. the PJM ORDC attributes value to having additional reserves that avoid the need for voluntary load shedding in the event of one or more contingencies, or contingencies combined with net load uncertainty[130]).
- The willingness to pay for services to cover **less credible or non-credible contingencies**, i.e. a high price for the minimum system requirements, and a lower price for services that go beyond that minimum (reflecting the value of these services to the SO in maintaining reliability over a probability distribution of potential system outcomes). In this sense, the demand curve would reflect a probabilistic view of potential disturbances and would take into account the cost, or even feasibility, of restoring the system to a secure state.
- The **interactions among ESS**. For example, the demand curve for inertia may express the trade-offs between purchasing additional inertia vs additional fast frequency response capability (such that the system can respond effectively to a higher RoCoF in a lower-inertia environment). For example, the minimum requirements for inertia might be reduced if the system can rely on more FCAS, so the capped portion of the demand curve could be shifted to the left.

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129 An additional consideration is that grid resilience falls as operating reserves fall, which increases the potential for uncontrolled load shedding following a contingency. This consideration can also further increase the value attributed to having higher operating reserves (and hence for the ORDC to have a less steep slope).

130 FERC, Docket No. EL19-58-000, PJM proposed revisions to the Amended and Restated Operating Agreement of PJM Interconnection, 29 March 2019 (link), pages 54 and 55.

Compatibility with wider market design options

6.52 **Centralised/decentralised procurement.** The concept of demand curves can work with both a self-scheduling approach to procurement as well as with a centralised procurement regime:

- In the self-scheduling approach, resources would commit themselves based on their own expectations of the market outcomes, and the knowledge of the demand curves for system services. They would be paid based on an ex-post assessment of the clearing price.[131]
- In the centralised approach, resources would make bids to provide one or more services, which the central authority would assess and select the optimal combination of resources, and compensate them according to the demand curve.

6.53 The information requirements on the market participants and the SO would differ, but the framework does not preclude either of these two approaches, as preferred by the policy makers, from being implemented.

6.54 **Ahead markets.** The demand curve concept is also compatible with a day-ahead market for energy. The options that are available are to implement (i) a demand curve for ESS in RT, or (ii) a demand curve for ESS both in RT and ahead-market, but not (iii) an ahead-market demand curve on its own. In practice, the same demand curve is typically used by system operators with both ahead and intraday/RT markets. Adding an ahead-market demand curve for ESS provided by resources that would need to operate at least at minimum load in the energy market would also be contingent on having an ahead-market in energy, so the economics of committing a resource to provide ESS could be jointly evaluated with the economics of the resources' minimum load energy output.[132]

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131 An ex-ante pricing would require AEMO to forecast which resources would come online and could result in low prices being forecast when the need is actually high.

132 It would be feasible to clear ahead markets for reserves independently of the energy market, but this would tend to result in extremely inelastic supply of ESS when energy market prices are volatile. This was the design of the California ISO in the 1998-2000 period which contributed substantially to extremely inefficient day-ahead unit commitment decisions. This would also likely lead to an increasing reliance on out-of-market actions by the system operator to balance load and generation.

6.55 While this is not currently part of the NEM design, we understand that the introduction of ahead markets is considered as a potential post-2025 change. We consider that there is potential for introducing ahead markets for the majority of ESS, including reserves, frequency response, as well as inertia and system strength. Indeed, ERCOT, NYISO, CAISO and MISO coordinate day-ahead markets for reserves and regulation, PJM and Ontario are implementing such a design and ISO NE coordinates most of these products in a day-ahead market.

Challenges with demand curves

6.56 The concept of demand curves works best for services that can be objectively defined, measured and monitored. For services that do not meet these requirements (e.g. system strength), it is likely to be more complex, but not necessarily unworkable, to define suitable demand curves.

6.57 Demand curves also require a central authority (this could be the system operator, the local regulatory authority, or a reliability oversight authority) to define specific targets (national, regional or local) for the relevant ESS and identify the resources which can count towards meeting a particular level of ESS demand. This may be more complex for services where the physical location is significant (e.g. where resources in a particular location may be more valuable for a particular system service).

6.58 As discussed in ¶6.12, the RT price signals for providing ESS may not always translate into efficient long-term investment signals. In some cases, market participants may perceive the RT price signals as being too volatile and unpredictable, or the supply too “lumpy”, and therefore be deterred from investing in the resources necessary to support long-term security and reliability. This is not necessarily a “bad” outcome per se, because it may reflect the correct marginal value of incremental investment given the uncertain need for it. One implication of this is that certain system services may not lend themselves well to the development of long-term price signals for investments, and an alternative approach may be more appropriate (for example, this uncertainty could be addressed by defining demand curves for particular ESS that will provide returns over a range of future outcomes). We examine in the following section which of the NEM ESS are likely to fall into this category.

6.59 As noted in Section 4, a procurement of system services based on voluntary bids and offers from market participants (as is the case in the demand curve approach), may be, in some cases, exposed to the risk that parties may seek to exercise market power, for example by withholding supply (i.e. not committing units able to provide specific services) with the objective of increasing the price received for other units, or in anticipation of higher compensation being received if the SO directs the resource on through a separate mechanism. Appropriate market power mitigation measures would need to be developed in the more detailed design stage. Market power mitigation options in the context of demand curve design might include those listed below (although other options may be envisaged depending on the specific circumstances):

- Capping the demand curve price paid to the seller with market power but not capping the price paid to fringe (non-pivotal) suppliers;
- Requiring that particular resources be committed when the projected price exceeded a specified level; and/or
- Allowing AEMO to commit resources possessing market power with a specified capped payment.

6.60 The concept of demand curves has been tried and tested in other jurisdictions, notably some of the US ISOs, but only for a subset of ESS, such as reserves and frequency response. For other ESS, the development of demand curves would represent an innovative design.

6.61 Wider changes to the NEM market design may also interact with the feasibility of the demand curve concept. For example, a potential introduction of more granular locational pricing would likely affect the definition of demand curves for ESS, which might need to be re-specified at the same granularity.

C. Demand Curves in Practice

6.62 In this section, we outline the process of creating a demand curve for operating reserves in practice, by providing a case study on the construction of NYISO’s ORDCs (although we also refer to other ISOs, where relevant). We then provide a stylised example of how the demand curve would work to set market clearing prices and quantities.

NYISO ancillary service market design

6.63 Since 2005, NYISO has operated a “nested” market design for ancillary services, in which bulk energy, frequency response and operating reserve products are co-optimised in both the day-ahead market and in RT, with the potential for distinct settlement prices for each product. The market is underpinned by NYISO setting procurement targets and constructing demand curves for each service at both regional and sub-regional levels.

NYISO operating reserves

6.64 In relation to operating reserves specifically, NYISO procures 3 types of products: (i) 10 minute spinning reserves; (ii) 10 minute reserves; and (iii) 30 minute reserves. Prices for each reserve are determined through NYISO’s construction of ORDCs, along with resource bids from market participants (which is analogous to a supply curve).

6.65 NYISO’s market software evaluates RT dispatch every 5 minutes and RT commitment decisions every 15 minutes.[133] Day-ahead market prices are set for hourly schedules and determined in the day-ahead market. RT prices are calculated every 5 minutes and settled based on the quantum of service provided in each 5 minute dispatch interval.[134]

6.66 Prices for each 5 minute dispatch interval are determined simultaneously with energy and other ancillary service prices in RT dispatch. Shortage prices for ancillary services are taken into account in the RT dispatch engine and will set both the shadow price, and price, for a given service when the demand curve is binding.

6.67 In the NYISO market design, there are no offer prices for reserves in the RT market. RT reserve prices are determined either by the out-of-market dispatch required, given ramp constraints, to meet the reserve target or by reserve shortage prices if the reserves are insufficient to meet the target.

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[133] NYISO, Operating Reserve Background Presentation, 24 January 2019 (link), page 22.

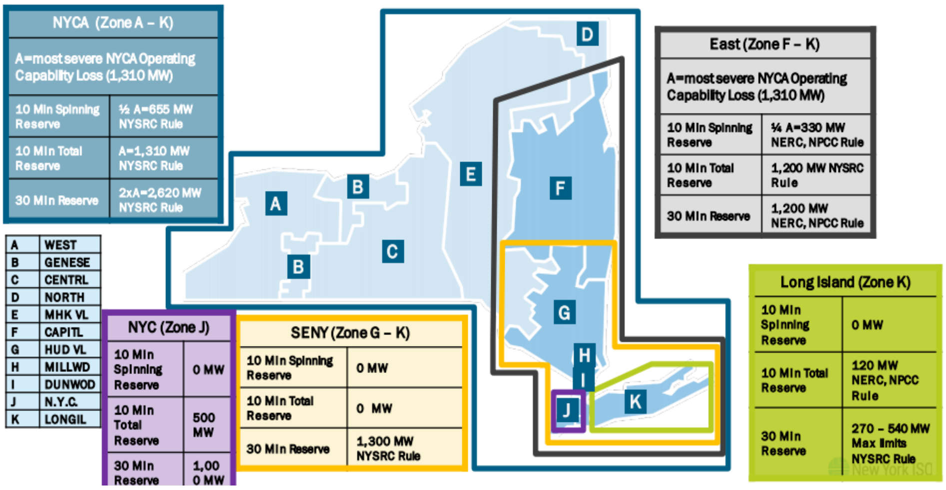
[134] The actual settlement invoices have an hourly granularity but they effectively settle suppliers based on the amount provided in each 5 minute interval by basing the settlements on the quantum of service provided in each 5 minute interval times the 5 minute interval settlement price.

6.68 When NYISO is short of reserves, the reserve shortage price will typically flow through directly into the energy price, as the dispatch of an additional MW of energy will create an additional MW of reserve shortage. This is because additional MW of energy are typically provided by generators that were providing the reserves.[135]

Construction of NYISO's ORDCs

6.69 In total, NYISO constructs 15 ORDCs, one for each reserve requirement, which can be broadly categorised as curves that (i) consider total requirements for a particular reserve product; or (ii) consider the location-specific requirements for a particular reserve product. For example, there are four ORDCs relating to 10 minute total reserves – three are location specific and the other one is system-wide.[136] The current operating reserve regions are displayed below in Figure 6-6.

Figure 6-6: Proportion NYISO operating reserve regions



Source: NYISO, Ancillary Services Shortage Pricing presentation, 7 April 2020 ([link](#)), page 15.
*Note: NYISO regions: New York Control Area ("**NYCA**"); East of Central-East ("**East**"), Southeastern New York ("**SENY**"), Long Island ("**LI**"), New York City ("**NYC**").*

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135 There are some circumstances in which this trade-off between energy supply and reserves shortages will not exist, meaning reserve prices will not be reflected in energy prices.

136 The 3 location specific spinning reserve products are for: (i) Eastern, Southeastern or Long Island; (ii) Southeastern or Long Island (iii) Long Island. Source: NYISO, Ancillary Services Manual, May 2020 ([link](#)), page 67.

6.70 In order to construct the ORDCs, NYISO establishes two key factors for each product:[137]

- **An hourly target** – the target is set to equal the quantum of the product (in MW) that NYISO would procure if the cost was less than the first shortage price;[138] and
- **A shortage price per MW –** this is the price that market participants would receive for providing the service when supply is less than or equal to the relevant target, thereby providing an incentive to offer reserves. NYISO is able to set different prices for different levels of shortage. For example, there are currently four different shortage prices for total 30 minute reserves, with higher prices for greater shortfalls.

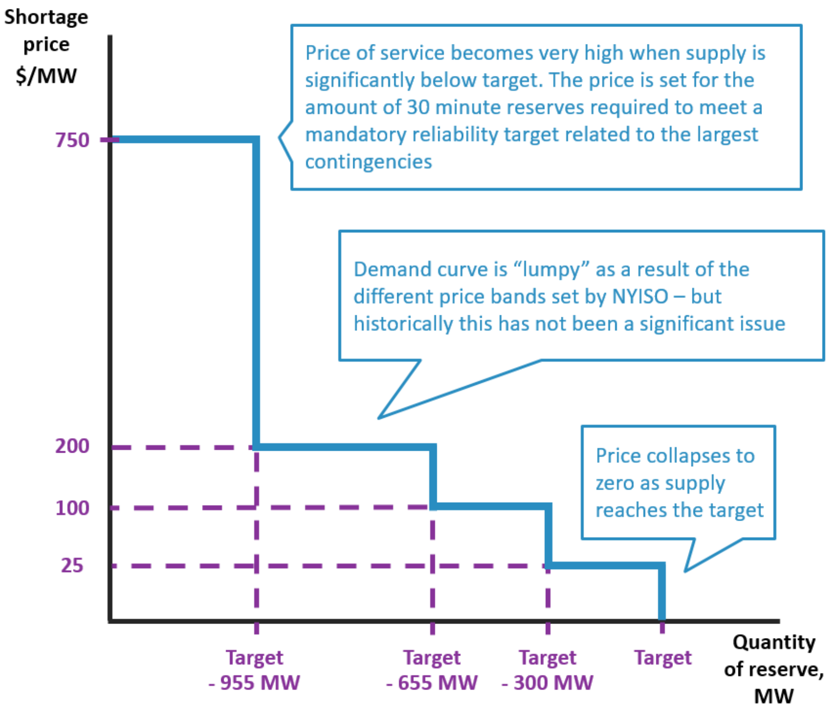
6.71 In other words, the ORDC is constructed by defining shortage prices associated with shortfalls relative to reliability and operational reserve targets.

6.72 An example curve, which uses the current target and shortage prices for 30 minute reserves in the New York Control Area region, is illustrated below in Figure 6-7 below.

137 NYISO, Ancillary Services Manual, May 2020 (link), page 67.

138 The actual wording the NYISO tariff is very general, stating that the target will be the quantum of reserve that "*NYISO would seek to maintain in that hour if cost were not a consideration.*" This affords significant flexibility to NYISO. Source: NYISO, Ancillary Services Manual, May 2020 (link), page 67.

Figure 6-7: Illustrative ORDC for NYISO 30 minute reserves



Source: FTI analysis of NYISO Ancillary Services Manual, May 2020 (link), page 71.

NYISO's process for establishing reserve targets and shortage prices

6.73 At a high level, the quantities of reserves at which steps in the demand curve occur relate to various different reliability targets.

- For example, NYISO is required to meet certain mandatory federal reliability targets, calculated as multiples of the largest single contingencies. These mandatory targets are responsible for the highest priced / lowest quantity steps in the curve.
- The steps at lower prices / higher quantities relate to reserve targets that are not required to meet federal obligations, but are for amounts of additional reserves that NYISO has decided to carry to better enable it to restore mandatory reserves following generation contingencies or other events that deplete its mandatory reserves, as well as to balance unexpected variations in net load without depleting its mandatory reserves.

6.74 However, this is not the only approach possible – targets could be defined and calculated based on other metrics (an example of an alternative approach proposed by PJM is discussed in Box 6-2 below).

6.75 As with the reserve targets, there is no single "right" way to set shortage prices. However, the prices should be defined to be consistent with the cost of the actions operators would take to maintain the specified level of reserves. This consistency helps to ensure that the software makes commitment and scheduling decisions that are consistent with those that would be taken by the operators, and also ensures that all low cost actions are taken before operators take higher cost options not evaluated in the software, such as activating demand response, starting behind-the-meter generation (highly polluting diesel engines), reducing voltage, *etc*.

6.76 Small reserve shortages will generally have much lower shortage prices, because the reserves that are depleted are those maintained to help rebalance the system at lower cost (without the need for extreme operator actions after sudden changes in load or supply), and are not required by mandatory reliability standards.

6.77 NYISO and its Independent Market Monitor ("**IMM**")[139] periodically conduct reviews of the ORDCs to assess whether the targets and prices, as well as any other aspects of the wider ORDC design, may need to be adjusted to optimise the markets.[140] IMM often makes recommendations in its annual State of the Market Report.

6.78 As an example of the process that can be used to revise demand curves, in its 2018 Report, MMU recommended that NYISO take the value of lost load ("**VOLL**") into account when establishing the upper bounds on its shortage pricing design, which would support NYISO's shift towards more reliance on energy prices to support resource adequacy (i.e. reducing the role of the current capacity market). The IMM argued that currently "*the demand curves for reserves in New York reflect an implied VOLL that is much lower than most reasonable estimates*".[141] In response, NYISO has investigated the potential application of VOLL to its ORDC construction, and has recommended that further collaboration with stakeholders is undertaken to assess the potential of such a change.[142]

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139 "*The Market Monitoring Unit is responsible for ensuring that the markets administered by [NYISO] function efficient and appropriately, and to protect both consumers and participants in the markets administered by [NYISO] by identifying and reporting market violations, market design flaws and market power abuses".* Source: NYISO Market Monitoring Website (link). Accessed 25/06/2020.

140 NYISO, Ancillary Services Manual, May 2020 (link), pages 69 & 70.

141 Potomac Economics, 2018 State of the Market Report for the New York ISO Markets, May 2019 (link), page 80.

142 NYISO, Ancillary Services Shortage Pricing Report, December 2019 (link).

6.79 Additionally, if NYISO identifies a short term need for ORDC modification to avoid operational or reliability problems, it may temporarily modify the curves for up to 90 days (consulting MMU and various other bodies, including the regulator, if circumstances reasonably allow).

6.80 The current shortage prices set by NYISO are displayed in Figure 6-8 below.

Figure 6-8: NYISO operating reserve shortage prices

New York Region	Type	Demand Curve Amount (MW)	Demand Curve Price ($)
NYCA	Spinning Reserve	All	$775.00
NYCA	10 Minute Reserve	All	$750.00
NYCA	30 Minute Reserve	300.0 655.0 955.0 remainder	$25.00 $100.00 $200.00 $750.00
Eastern New York (EAST)	Spinning Reserve	All	$25.00
	10 Minute Reserve	All	$775.00
	30 Minute Reserve	All	$25.00
Southeastern New York (SENY)	Spinning Reserve	All	$25.00
	10 Minute Reserve	All	$25.00
	30 Minute Reserve	All	$500.00
New York City (NYC)	Spinning Reserve	All	$25.00
	10 Minute Reserve	All	$25.00
	30 Minute Reserve	All	$25.00
Long Island (LI)	Spinning Reserve	All	$25.00
	10 Minute Reserve	All	$25.00
	30 Minute Reserve	All	$25.00

Source: NYISO, Ancillary Services Shortage Pricing presentation, 7 April 2020 (link), page 17.

Box 6-2: PJM operating reserves

Like NYISO, PJM procures operating reserves using ORDCs. Historically, PJM's approach to constructing demand curves has been similar to NYISO's – using a demand curve that increases in vertical "steps" as the supply of reserves falls further and further below the mandatory reserve requirements, until a maximum shortage price (or penalty price, in PJM terminology) is reached.

However, PJM is currently in the process of moving to a system in which the demand curves are based on a "*systematic, probabilistic quantification*" of load and supply uncertainties and the need for operators to take actions to ensure that these uncertainties do not cause PJM to violate the mandatory reliability requirements.[143] This will enable PJM to value and procure reserves that are provided in excess of the mandatory minimum requirements, based on the likelihood that RT conditions will differ from forecasts, avoiding the need for operator out-of-market actions to procure these additional reserves. This is an example of the resilience benefits that are discussed in ¶6.51.

Specifically, PJM is proposing to use the previous three years of historical data to estimate the degree of uncertainty and net forecast error, which will then be used to calculate the incremental value of reserves provided in excess of minimum requirements.[144] This will then be used to construct an ORDC that falls smoothly, rather than being stepped, downwards once the minimum reserve requirement has been reached.

6.81 The same demand curves are used to price reserve shortages in the day-ahead and RT markets, but most ORDCs rarely bind in the day-ahead market because the commitments needed to meet the reserve requirements can be made within the timeframe of the day-ahead market. The set of resources available to respond to unexpected changes in RT conditions is more limited and is more likely to result in reserve shortages of periods of time in RT operations.

6.82 Within dispatch, the market software considers a number of constraints. This includes transmission constraints, which may result in the software going "short" on reserves within a constrained area by dispatching reserves to meet load to avoid exceeding the transmission constraints.[145]

143 FERC, Docket No. EL19-58-000, PJM proposed revisions to the Amended and Restated Operating Agreement of PJM Interconnection, 29 March 2019 (link), Filing Letter, page 12.

144 FERC, Docket No. EL19-58-000, PJM proposed revisions to the Amended and Restated Operating Agreement of PJM Interconnection Filing Letter, 29 March 2019 (link), pages 60 to 62.

145 NYISO, Operating Reserve Background Presentation, 24 January 2019 (link), page 22.

6.83 An additional layer of complexity is added to the process as a result of the "nested" nature of a number of the reserve targets in the NYISO market, meaning that reserves provided at some locations would meet multiple requirements, which are then reflected in the market price at that location. For example, the supply of spinning reserves also counts towards the 10 and 30 minute reserves targets, meaning that the actual price received by the provider of spinning reserves is equal to the sum of: (i) the spinning reserve shadow price; (ii) the 10 minute reserve shadow price; and (iii) the 30 minute reserve shadow price. Similarly, 30 minute reserves located in New York City meet the New York City 30 minute reserve target, the Southeast New York 30 minute reserve target, the east 30 minute reserve target and the New York Control Area 30 minute reserve target, and would therefore be paid the sum of the shadow prices. This means that if NYISO were short of 30 minute reserves within all these regions, resources providing 30 minute reserves located inside New York City would be paid the sum of the reserve shortage prices for all four of these regions.

Evolution of NYISO ORDCs

6.84 The market design has evolved since its introduction in 2005. Originally, it contained reserve targets and prices for only the New York Control Area as a whole, the East region (defined by the region east of a major voltage and stability transmission constraint) and Long Island. However, NYISO found the design to be effective in sending a price signal to guide market participant actions and subsequently expanded the design to cover reserve scheduling and pricing in two additional subregions of New York, both within the east region. These changes both set explicit prices on reserves and allowed ad-hoc operator actions to be replaced with software optimisation decisions, resulting in more cost effective actions as the software is able to evaluate all options (which is not possible for operators in the context of RT operations).

6.85 More recently, the large discontinuity between the $750 shortage price for violating the mandatory reserves target and the $200 price set for small shortages (see Figure 6-7 above) has the potential to result in price discontinuities from the commitment of an additional unit or reduction in load during shortage conditions. This potential price discontinuity has not been much of an issue historically in the NYISO market, but evolving market conditions and the goal of strengthening energy market pricing incentives has driven NYISO to propose adding a number of additional pricing steps, so that the largest price step in the ORDC would be $125. This has the explicit goal of avoiding large price discontinuities.[146]

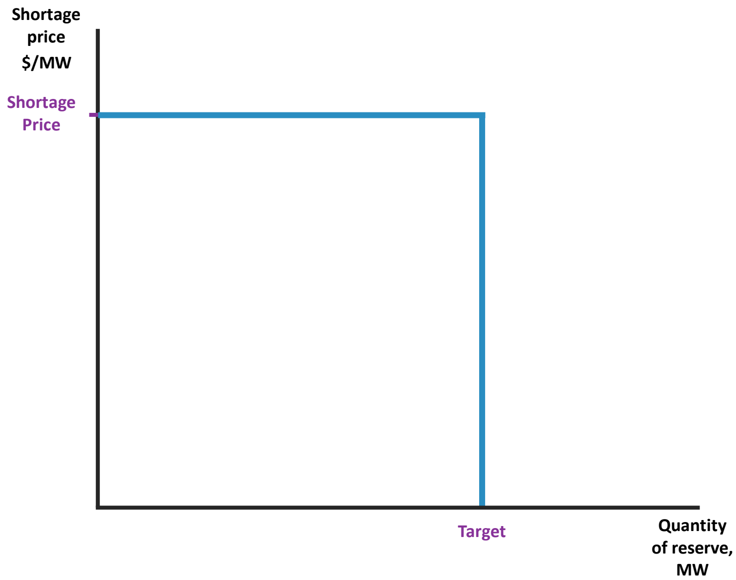
[146] NYISO, Ancillary Services Shortage Pricing Presentation, 27 April 2020 (link), page 16.

6.86 NYISO plans to continue adjusting, extending and refining this design to meet reliability needs as the level of VRE on the system continues to rise. For example, NYISO has recently proposed to its stakeholders an increase from four to nine different shortage prices for 30 minute reserves.[147]

Market operations with an ORDC

6.87 Figure 6-9 below illustrates a very simple ORDC, which is constructed by defining a single target MW and a single shortage price.

Figure 6-9: ORDC in Practice – a simple ORDC

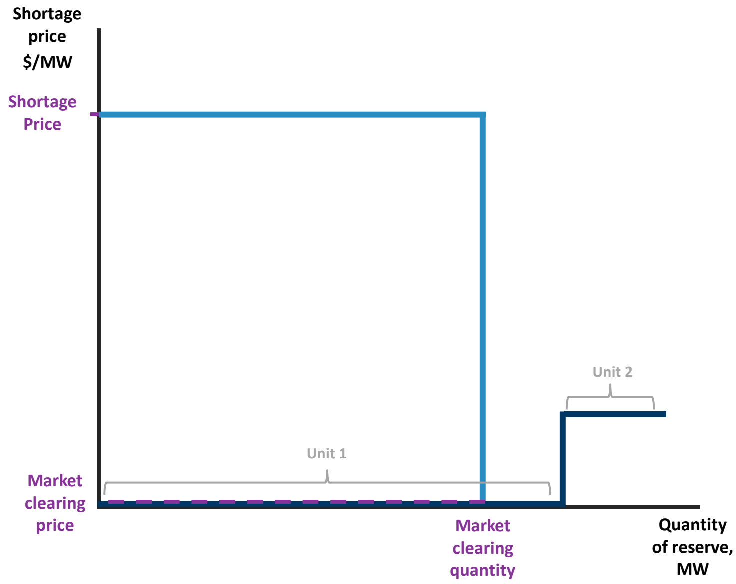


Source: FTI analysis

6.88 When the ORDC is used to set market clearing prices and quantities, there are three broad possible outcomes that can occur. First, there is the possibility that sufficient reserves will be provided as a by-product of bulk energy (and at zero marginal cost to producers). This outcome is illustrated in below, and results in a market clearing price of zero for reserves and a market clearing quantity equal to (or even greater than) the target.

147 NYISO, Ancillary Services Shortage Pricing Presentation, 27 April 2020 (link), page 11.

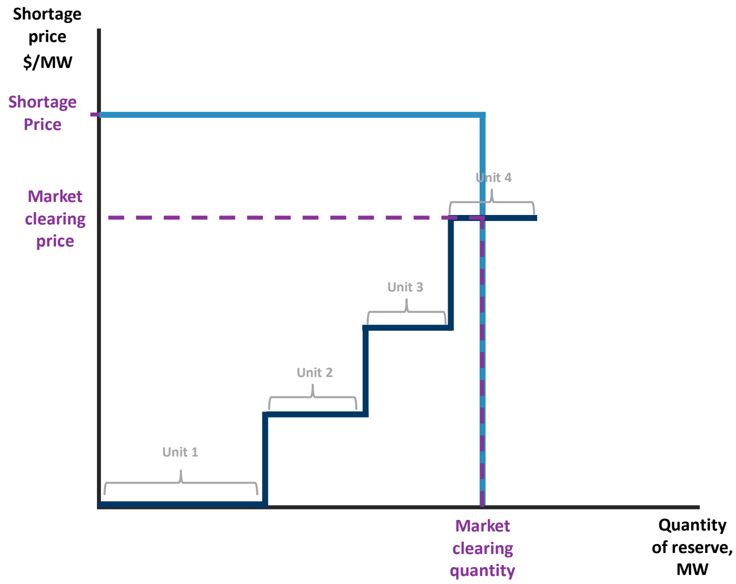
Figure 6-10: ORDC in Practice – Sufficient Reserves Provided as a By-product



Source: FTI analysis

6.89 The second possible outcome is that insufficient reserves are provided as a by-product of bulk energy, but there are sufficient bids in to the reserve market to meet the target at a clearing price that is less than or equal to the shortage price. This is illustrated in Figure 6-11 below, and results in a non-zero market clearing reserve price and a market clearing quantity equal to the target.

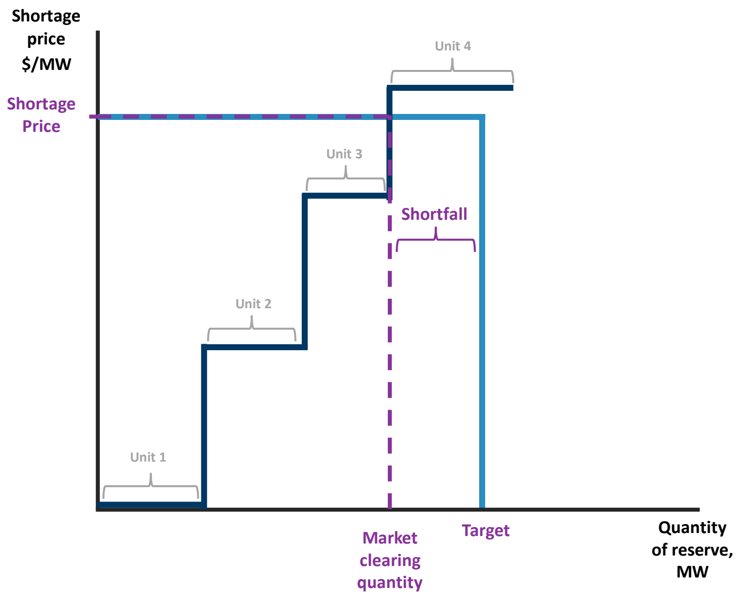
Figure 6-11: ORDC in Practice – Market Clearing Price Below Shortage Price



Source: FTI analysis

6.90 The third possible outcome is that insufficient reserves are provided as a by-product of bulk energy and a shortage occurs, and there are insufficient bids to meet the reserve target at a clearing price that is less than or equal to the shortage price. This is illustrated in Figure 6-12 below, and results in the reserve price that equals the shortage price, and a market clearing quantity below the target.

Figure 6-12: ORDC in Practice – Market Clearing Price Equals Shortage Price



Source: FTI analysis

6.91 It should be noted that in this scenario, NYISO would attempt to procure the quantity of reserves required to meet any mandatory requirements. However, this would occur through out-of-market mechanisms and the cost could exceed the maximum shortage price, which would not provide an accurate price signal to the market.

Interaction between NYISO reserve and energy market

6.92 These reserve shortage prices flow directly into NYISO energy prices through the joint optimisation of reserves and energy in the NYISO's RT dispatch. When capacity providing reserves is dispatched for energy to meet load, the change in the cost of meeting load in the objective function of the NYISO's dispatch is the sum of the (i) incremental cost of the energy dispatched; and (ii) the shortage price of the reduction in reserves when the reserves are converted to energy.

6.93 Thus, if a resource providing 30 minute reserves were dispatched for energy with an incremental energy offer of $125/MWh, and the shortage price of 30 minute reserves was $100/MWh, then the price of energy would be $225/MWh, reflecting the sum of the incremental energy offer and the increased reserve shortage costs.

6.94 Because all 10 minute spinning reserves and 10 minute total reserves count against the 30 minute reserve target, their price would rise to at least $100/MWh.

6.95 If NYISO’s reserve shortage deepened and the shortage price for 30 minute reserves rose to $750/MWh, the price of energy would be set by the sum of the incremental energy offer of the resource dispatched for energy and the $750 shortage price (i.e. $875/MWh with the $125 incremental energy offer assumed above). As above, the price of 10 minute spinning reserves and 10 minute total reserves would also be set by the price of 30 minute reserves, so would rise to $750.

6.96 If NYISO’s reserve shortage deepened and all 30 minute reserves were activated in order to maintain 10 minute reserves and NYISO became short of 10 minute reserves, the NYCA energy price would rise to $1625, the sum of the $750/MWh shortage price for the final step of 30 minute reserves, the $750 penalty price for NYCA 10 minute reserves and the assumed $125 incremental energy offer.

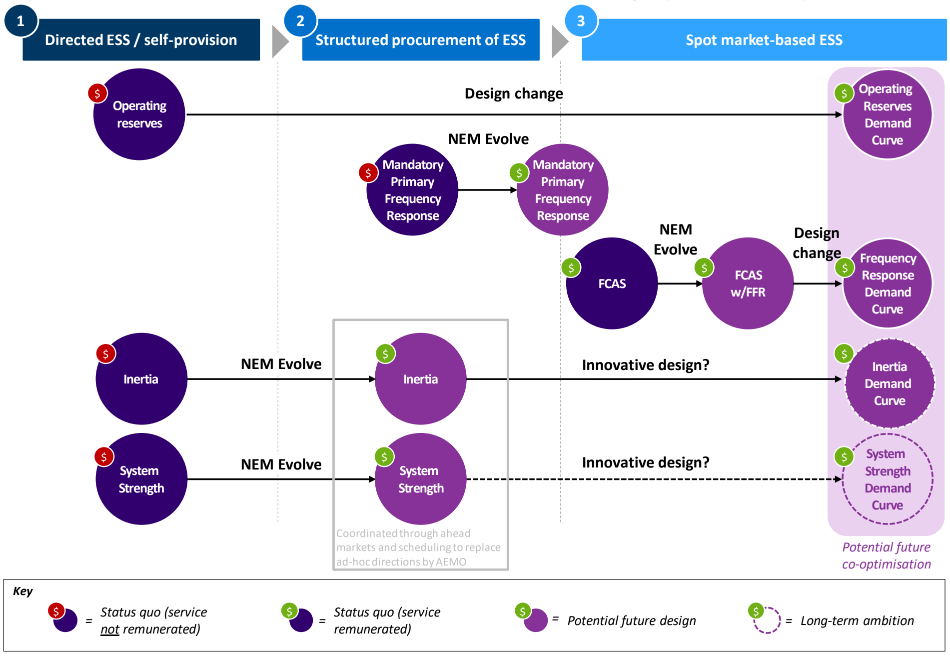
6.97 A NYCA wide shortage of 30 minute reserves and 10 minute reserves would also result in a shortage of 30 minute reserves in the east and SENY regions and 10 minute reserves in the east region, resulting in much higher energy and reserve prices in these regions.

7. Pathways for ESS

7.1 As set out in the previous section, there is a wide range of different options and approaches to procuring and scheduling ESS. In this section, we consider how these options could be applied to different system services. Specifically, we focus on services where a case for change has been identified in Section 3. This includes **operating reserve**, **frequency response**, **inertia** and **system strength** (Sections A to D). **Strategic reserves**, alongside directions by AEMO (e.g. for system strength adequacy) are assumed to remain a last-resort tool in the NEM and would therefore remain out-of-market.[148] In Section E, we explore how **synchronous services** (inertia, voltage support and system strength) could be jointly procured and scheduled.

7.2 An overview of the pathways described in this section is in Figure 7-1 below.

Figure 7-1: Overview of procurement and scheduling options for specific ESS



Source: FTI analysis

148 Voltage control has not been identified as having a strong case for change.

7.3 In making the decision to move from one option to the next, it is important to consider the following factors (while also taking into account the principles for procurement and scheduling of ESS set out in Section 4).

- The likely **costs** of making the change, e.g. in terms of the implementation costs and the ongoing costs of the new regime for market participants, AEMO (e.g. software costs) and for regulatory authorities (e.g. in terms of monitoring and enforcement);
- The likely **costs** of <u>not</u> making the change, e.g. the foregone opportunity to improve efficiency of procurement, or the cost of the next-best alternative (which might be the cost of continued ad-hoc directions by AEMO);
- The likely **benefits** of making the change, e.g. the expected reduction in costs of ensuring system security (both from a static point of view, and from a dynamic point of view, i.e. whether the changes are likely to incentivise further innovation or cost reductions in the long term). The benefits, along with the costs of <u>not</u> making the change, are likely to be driven by the speed at which NEM transitions to a VRE/IBR-dominated world; and
- The **risks** associated with the change, for example any unintended consequences that the changes may cause, and/or unintended costs that may potentially be imposed on consumers.

7.4 The remainder of this section presents the different options available for different system services. At the end of this report, in Section 9, we discuss how these pathways may be considered jointly as part of a potential roadmap for the NEM.

A. Pathway for reserves

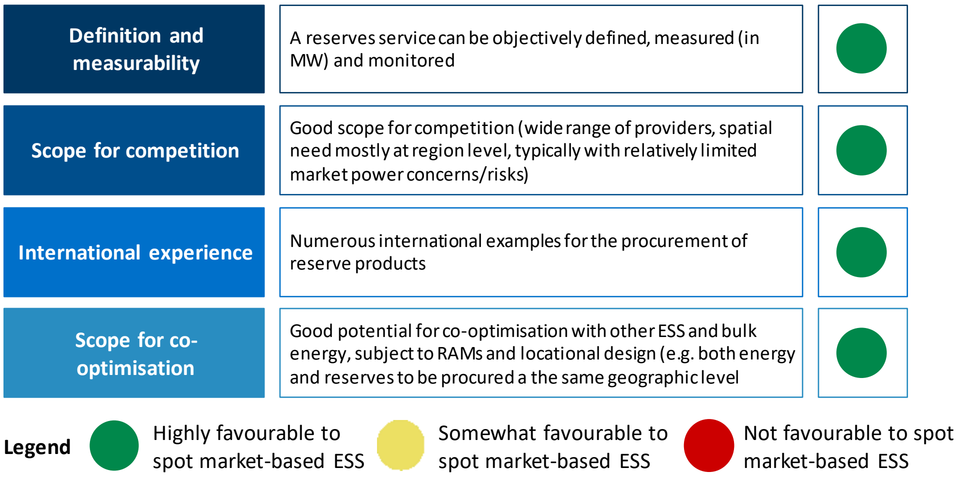
7.5 Strategic reserves and operating reserves are currently treated as two separate services in the NEM (defined as out-of-market and in-market reserves respectively).

- Operating reserves are provided by wholesale market participants, but they do not currently constitute a separate formal service procured and scheduled in the NEM.

- Strategic reserves are procured by AEMO through the RERT mechanism. The RERT, and its relative merits as a mechanism to ensure resource adequacy, is examined as part of a separate strand of ESB's post-2025 market design work.[149]

7.6 The main characteristics of reserves as a system service are summarised in Figure 7-2 below. Reserves are a well-understood concept in the NEM and internationally, with a range of precedents that can be leveraged when considering modifications to the NEM design, including the use of demand curves for this service.

Figure 7-2: Characteristics of reserve services



Source: FTI Analysis

7.7 In the following subsections we consider the merits of potential adjustments to the current NEM design ("**NEM Evolve**") and the merits of more fundamental design changes to operating reserves.

A.1 NEM Evolve

7.8 As discussed in Section 2, the NEM already has processes to procure and schedule **strategic reserves**, and the RERT has undergone progressive reforms in recent years in order to facilitate the procurement of strategic reserves. The NEM Evolve option would therefore involve a continuation of the existing arrangements, such that strategic reserves could continue being adapted through the AEMC rule change processes.

149 RERT is also examined in a separate FTI report - Resource Adequacy Mechanisms in the National Electricity Market. A Report for the Energy Security Board, 2020.

7.9 There is, however, no formal process for procuring and scheduling **operating reserves**, which are provided by market participants without explicit renumeration (other than through RT energy prices).

7.10 Overall, the NEM Evolve option would not represent a significant departure from the status quo. As shown in Table 7-1 below, there are a number of disadvantages associated with the NEM Evolve option as the potential for reform would be foregone. This opportunity for reform would also depend on whether any wider NEM market design changes were to happen at the same time[150] since such reforms could influence the preferred approach to reserves.

Table 7-1: NEM Evolve for operating reserves

Advantages	Disadvantages
✓ Simplicity and minimum departure from the status quo.	× Risk of insufficient operational and/or investment price signal to deliver an adequate volume of reserves (e.g. if the exposure to Regional Reference Price ("**RRP**") in RT does not impose a sufficient penalty and participants choose to maintain lower-than-optimal levels of operating reserves from the system operation perspective. × The operational and investment efficiency may be compromised if reserves continue to be procured without explicit co-optimisation with bulk energy (as the total cost of operating the system may be higher than necessary). × Consumers may be exposed to excessive risk of high total system costs if market participants fail to maintain adequate operating reserves (thus triggering last-minute actions by AEMO).

Source: FTI analysis

A.2 Design change

7.11 There are two possible design changes for the procurement and scheduling of reserves.

- First, operating reserves could be designed as a specific system service, but procured through non-spot-market (similar to how strategic reserves are currently procured).

150 For example, the implementation of ahead markets or more granular locational pricing may have a significant impact on market participants' decisions to hold operating reserves.

- Second, operating reserves[151] could be procured through market-based approaches, loosely modelled on the ORDC precedents in the US.

7.12 In relation to the non-spot-market provision of operating reserves, we set out the advantages and disadvantages of this option in Table 7-2 below.

Table 7-2: Structured procurement of operating reserves

Advantages	Disadvantages
✓ Direct control by AEMO in terms of procuring a specific volume of reserves. ✓ Ability to retain separate "silo" for operating reserves. Keeping a separate "silo" for the strategic reserves means that the NEM does not fundamentally move away towards a formal capacity market design (which we recognise is explored through a separate strand of work on RAMs). ✓ Non-spot-market-based procurement can provide an explicit price signal for ESS and encourage additional providers to enter the market, possibly using different technologies (although less so than in a spot-market-based provision, discussed below).	× Lack of a forward price signal for investment × Continued reliance on out-of-market actions by AEMO, which may unnecessarily increase costs to consumers, or limit the variety of resources and technologies that can compete to provide ESS. × Departure from the status quo where market participants make their own decisions regarding the amount of spare capacity they hold within their portfolio (or contract for with third parties) to protect against unexpected net load changes. × Lack of competition may lead to unnecessarily high costs incurred by AEMO in procuring the service. This could be partly mitigated through price caps on the contracts that AEMO may enter into with third parties, although these are likely to be less efficient than competitive pressure.

Source: FTI analysis

7.13 The main characteristics of operating reserves, summarised in Figure 7-2 above, allow for spot-market-based procurement and scheduling (Option 3 in Figure 7-1). In this approach, the price for operating reserves would be determined by the intersection of the formulated demand curves and the provider supply curves.

7.14 We set out the advantages and disadvantages of spot-market-based provision of operating reserves in Table 7-3 below.

151 We do not discuss strategic reserves (RERT) in this section. We discuss this mechanism in more detail in a separate FTI report - Resource Adequacy Mechanisms in the National Electricity Market. A Report for the Energy Security Board, 2020.

Table 7-3: Spot-market-based provision of operating reserves

Advantages	Disadvantages
✓ Demand curves for reserves enable the SO to define exactly what it is willing to pay (on behalf of consumers) for any given quantum of reserves, and only pay for the required amount. ✓ Competitive provision of reserves is likely to reduce costs relative to non-market approaches. ✓ The provision of reserves could be co-optimised with energy and FCAS, which is likely to lead to lower overall system costs to consumers. More generally, optimisation decisions coordinated in the market are likely to allow more efficient choices by the SO than if the resolution of these issues is left to ad-hoc operator actions. ✓ An explicit price signal for ESS is likely to send appropriate investment signals and encourage additional providers to enter the market, possibly using different technologies. This should result in a lower cost solution in the long run. ✓ The cost vs quantity trade-offs embodied in the demand curves allow regulators and other stakeholders to observe the cost of procurement targets and perhaps modify them to reflect their social value and cost. ✓ There is potential for combining the provision of strategic and operating reserves in case policy makers choose to move towards a more explicit RAM for both services. Moving to a design in which they are more linked as an overall reserve requirement could help reduce overall costs of operating the system. ✓ The basic design can be applied in combination with a wide range of approaches described in Section 5. Rather than committing to a single option, the policy makers continue facing a menu of sub-options within the "demand curve framework", which can be refined over time. ✓ Readiness for implementation: by selecting conservative parameters and by focusing on services where international experience can be leveraged, the overall framework can be implemented, as a starting point, by 2025.	× Greater complexity arising from the need to centrally procure all three services – energy, frequency response and reserves (particularly if demand curves are defined in a nested manner, as part of a fully co-optimised design). × Additional requirements for designing the regime, including the need to define the initial demand curves, a cost recovery methodology, and an approach to resource commitment and dispatch, as well as wider practical implementation challenges.

Source: FTI analysis

7.15 There is extensive international experience with ORDCs, particularly in some US ISOs, which means that the NEM can draw on those experiences to develop a tried-and-tested approach. Section 6C presents a case study on the ORDC in NYISO.

7.16 However, as set out in Table 7-3 above, there are complexities involved in designing the spot-market-based regime. In the following subsections we explore, in turn, the need to define the initial demand curves, a cost recovery methodology, and an approach to resource commitment and dispatch, as well as wider practical implementation challenges.

Demand curves for reserves

7.17 To implement the spot-market-based approach for the procurement and scheduling of reserves, demand curves for reserves would need to be defined. However, it is not necessary to define the "perfect" demand curves in the initial implementation. The initial demand curves will reflect a starting point that can be adjusted and refined to reflect operating experience and the continuing evolution of the NEM resource mix and technology. AEMO could have a degree of flexibility in adjusting the parameters that define these demand curves and the software used would be designed to enable this flexibility (which has become the existing practice with software vendors internationally), although the degree of flexibility needs to be considered against the potential risk that frequent changes might deter investment.[152]

7.18 The two main dimensions required to define the demand curves for reserves are the geographical granularity and the quantum of the target, as set out in turn below.

7.19 First, regarding the **geographical granularity**, the demand curves could initially be defined at the NEM level. However, if there was the potential for congestion on the transmission network, it will be essential that requirements are (at least partly) locational to ensure that that the necessary resources are not behind transmission constraints. A core challenge for the system design is whether the intended optimal outcomes can be fully achieved with the current non-locational energy pricing design in the NEM.

[152] The appropriate flexibility in setting various parameters of the ESS design is discussed in Section 8.

7.20 NEM-wide procurement would tend to naturally result in reserves being scheduled behind transmission constraints (where reserves would appear to be low-cost in the AEMO dispatch precisely because the energy could not be dispatched), so some locational requirements will be necessary. Ongoing experience in MISO and CAISO of using reserves to balance variations in intermittent resource output has shown that it is critical to model locational requirements.

7.21 The regional demand for reserves would be nested within the NEM-wide requirements, meaning the contribution of a resource to meeting the regional target would also count towards the NEM-wide target.

7.22 Second, regarding the **quantum of target**, the demand curves would need to express a target MW that would meet the requirement for reserves. There are three high-level options:

- The target could be fixed and specified in advance. This is the traditional approach, typically based on the size of the single largest contingency on the system, but is unlikely to be the most appropriate way of expressing the target in a future with high VRE deployment.
- The target could be based on historical projections for the variability of RT output during particular times of day and year. This is the current CAISO design for setting flexi-ramp procurement targets, which balance intermittent resource output. While such a design could be implemented relatively straightforwardly, it has been found to have significant shortcomings due to its lack of direct relationship to the projected level of intermittent resource output for the target period.
- The target could be based on projected future system conditions and, in particular, on the projected level of intermittent resource output during the target period. This is the design CAISO is moving to and it ties the target to the projected level of intermittent resource output and net load. If projected variable resource output is low, less reserves are needed. If projected variable resource output is high, more reserves are needed as any forecast error will have a greater absolute magnitude. However, this option has not been fully developed or implemented by CAISO, so the complexity remains uncertain (and a potential barrier). Nonetheless, analysis to date shows the potential for significant improvements in defining targets relative to the existing approach. Moreover, this approach appears consistent with AEMO's methodology for defining FUM.

7.23 Given the experiences from other jurisdictions, we consider that the implementation of the second or third approaches above could be examined as a potential path forward for the NEM. In any event, the most appropriate approach for each NEM region would be determined through ongoing analysis and likely evolve over time.

Cost recovery methodology

7.24 A suitable cost recovery methodology for the cost of an operating reserve product, incurred by AEMO on behalf of consumers, would need to be developed. As set out in Section 4, this could be based on the "causer-pays" or the "beneficiary-pays" principle. However, there are other alternatives that may be considered, based on policy maker preferences (and largely independently of other design choices), including (i) costs being averaged and allocated to all load; (ii) partly allocated based on a variety of "causer-pays" or "beneficiary-pays" rules and partly smeared across load,[153] or (iii) a mix of the previous options.

7.25 The proposed pricing designs would also generate revenues to cover the uplift costs in some circumstances, such as if VRE were dispatched down economically when low system strength limited VRE output.

Resource commitment

7.26 The demand curve design would also need to ensure that resources are committed over an appropriate timeframe. In general, the simplest design is to procure resources in RT, as this design can be used while fully co-optimising with energy prices and schedules. However, this would not result in efficient outcomes for:

- Resources that require advance notice to pre-commit (e.g. slow-starting units); and/or
- New resources that need to commit to an investment potentially many years ahead of time.

153 For example, more reserve costs might be allocated to retailers and suppliers whose net load variations create more need for AEMO to schedule reserves for balancing.

7.27 The appropriate design for resource commitment (i.e. the ability to procure ESS ahead of time) will also be influenced by the developments of potential ahead-markets in the NEM and the relationship between the system services and ahead markets would need to explored further as part of the post-2025 market design.[154]

7.28 For example, one could envisage an ahead-market that allows a centralised scheduling (commitment) of resources for energy, which could subsequently be expanded into an ahead-market for reserves (or other ESS). This would differ from the status quo, as currently the NEM has no formal ahead or intraday energy market.[155] While some parties may consider that the financial contracts and pre-dispatch that do exist in the NEM amount to a quasi-ahead-market, we consider that they do not constitute an effective ahead market, for the following reasons:

- While financial contracts enable parties to financially hedge their RT positions, they do not directly translate into physical commitments and hence do not act as an ahead-market.
- Similarly, pre-dispatch does not constitute an ahead-market either since it does not translate into physical commitments (parties can adjust their positions up to RT, subject to good faith commitments), nor is there a financially binding obligation arising from pre-dispatch.

Dispatch and commitment rules

7.29 Related to the commitment issues above, the design will need to define dispatch and commitment rules.

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154 Ahead-markets are considered separately by ESB as part of the Post-2025 Market Design Programme.

155 A forward market for FCAS in the NEM has been discussed in the past but does not currently exist either.

7.30 The procurement of operating reserves could be restricted to online resources, spinning reserves, or to a combination of spinning reserves and quick starting offline reserves that can be dispatched for energy based on the energy prices and the reserve demand curve. AEMO could adjust the mix of online and offline reserves over time as the resource mix evolves and as AEMO gains operating experience with the new resource mix.[156]

Wider practical implementation considerations

7.31 Finally, there is a range of practical implementation considerations involved in operationalising the concept of locational ORDCs. For example:

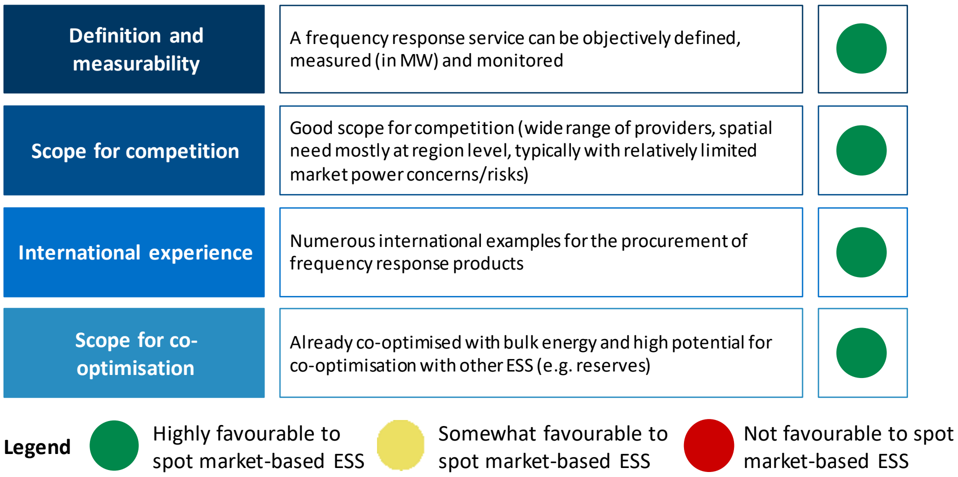
- Software would need to be developed, tested and implemented;
- The impact on the settlement system would need to be evaluated (e.g. learning from the NEM's move to 5-minute settlement);
- The design would need to be "future-proofed" to ensure that further changes can be incorporated smoothly; and
- Monitoring, evaluation and change processes would also need to be developed, to enable a regular review and refinement of the design.

B. Pathway for frequency response

7.32 Frequency response services (FCAS) are currently co-optimised with bulk energy in the NEM. Their main characteristics are summarised in Figure 7-3 below.

[156] We note that this only applies to operating reserves. By contrast, for strategic reserves, the dispatch approach above is unlikely to work because the relevant resources would be offline, with varying amounts of time required to bring them online, and varying costs of bringing them online. To bring strategic reserves online, there has to be a commitment decision made by an entity (e.g. the SO).
This raises the question of who should be able to make the commitment decision for offline reserves. In most markets, offline reserves are typically committed by the SO (but sometimes this is restricted to contingency responses), which could also be the approach considered in the NEM. However, this may not be the only available option; for example, the SO may only be allowed to commit offline resources based on price projections, in pre-defined circumstances, or based on other rules.

Figure 7-3: Characteristics of a frequency response service



Source: FTI Analysis

7.33 In the following subsections, we consider the merits of the NEM Evolve option and the merits of more fundamental design changes to the provision of frequency response.

B.1 NEM Evolve

7.34 The NEM Evolve approach to frequency response would focus on refinements of the current FCAS and MPFR mechanisms.

- For FCAS, these adjustments could involve the introduction of a new FCAS product (e.g. a new contingency FCAS product with a response time of less than 6 seconds, or a refinement to the regulation FCAS product), meaning the system is able to better respond to frequency deviations driven by lower system inertia.[157]
- For MPFR, this could involve the introduction of a formal compensation process, replacing the mandatory nature of this service. This potential evolution of the NEM arrangements is already under consideration.[158]

157 This is currently under consideration through the AEMC's Rule Change Request process. Source: AEMC, Fast frequency response market ancillary service website (link). Accessed 08/07/2020.

158 AEMC are currently considering a rule change request aiming to remove perceived disincentives to generators for providing primary frequency response. Source: AEMC, Primary frequency response inventive arrangements (link). Accessed 08.07.2020.

7.35 AEMC has also recently explored a number of options for evolving the current NEM framework for frequency control, ranging from regulated approaches to market-based approaches. [159]

7.36 The approaches that provide a more direct control over frequency response included:

- A mandatory requirement for generators to maintain headroom to provide frequency response, which could be used through central dispatch instructions or local responses; and
- A process of contracting or tendering for the provision of frequency response, where the volume of required frequency response was determined ahead time and contracted with market participants.

7.37 Conversely, the approaches that provide a less direct (and more “distributed”) control over frequency response included:

- The introduction of self-forecasting by market participants to incentivise them to reduce their impact on system frequency; and
- A performance-based pricing approach, such as a deviation pricing mechanism, where participants’ decisions to respond to frequency changes are based on the incentives provided through a transparent pricing mechanism (i.e. without any central intervention).

7.38 The options set out in AEMC’s draft report are all intended to be able to integrate with the existing NEM design without considering more substantial changes to the design of the wholesale energy market (i.e. “NEM Evolve”).

7.39 Overall, the NEM Evolve option would aim to represent a relatively modest augmentation of the status quo. While we do not consider each of the potential options for frequency control in detail in this report (this has been considered by AEMC, see footnote 159), Table 7-4 below sets out the main disadvantages associated with this option. We find that the main disadvantage of the NEM Evolve option, relative to a more fundamental change in market design, would be the potential for inefficiency arising from the lack of consideration of wider system needs, and the foregone potential for reform.

159 AEMC, Frequency Control Frameworks Review, 20 March 2018 (link).

Table 7-4: NEM Evolve for frequency response

Advantages	Disadvantages
✓ Simplicity and minimum departures from the status quo. ✓ Continued co-optimisation with bulk energy.	× The operational and investment efficiency may be compromised if the provision of frequency response services does not take into account the wider system needs, such as the interaction between frequency response and inertia (this is explored below in Section B.2), or between frequency response and reserves… × …which means that the NEM Evolve would likely continue a relatively siloed approach, potentially to the detriment of long-term interest of consumers.

Source : FTI analysis

B.2 Design change

7.40 The main characteristics of frequency response, summarised in Figure 7-3 above, allow for spot-market-based procurement and scheduling (Option 3), as well as for explicit demand curves to be expressed for the service. In this approach, the price for frequency response would be determined by the intersection of the demand and supply curves.

7.41 The advantages and disadvantages of procuring and scheduling frequency response through spot market demand curves are similar to those described for reserves in the previous section and are summarised in Table 7-5 below.

Table 7-5: Demand curve-based provision of frequency response

Advantages	Disadvantages
✓ Demand curves for reserves enable the SO to define exactly what it is willing to pay (on behalf of consumers) for any given quantum of frequency response, and only pay for the required amount ✓ Competitive provision of frequency response is likely to reduce costs relative to non-market approaches. ✓ The provision of frequency response could be co-optimised with energy and other relevant services (e.g. reserves), which is likely to lead to lower overall system costs to consumers. More generally, optimisation decisions coordinated in the market are likely to allow more efficient choices by the SO than if the resolution of these issues is left to ad-hoc operator actions.	× Greater complexity arising from the need to centrally procure all three services – energy, frequency response and reserves. × Departure from the existing design of FCAS. × Additional requirements for designing the regime, including the need to define the initial demand curves, a cost recovery methodology, and an

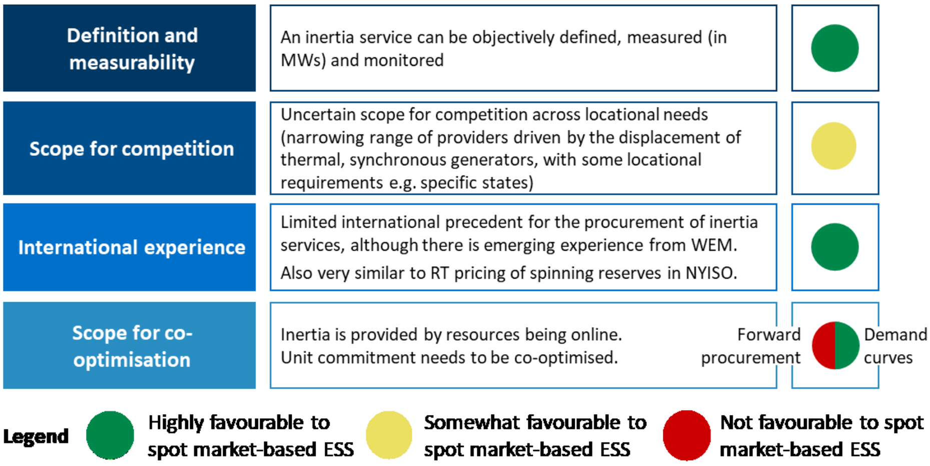
Advantages	Disadvantages
✓ An explicit price signal for frequency response is likely to send appropriate investment signals and encourage additional providers to enter the market, possibly using different technologies. This should result in a lower-cost solution in the long run. ✓ The cost vs quantity trade-offs embodied in the definition of the demand curves will allow regulators and other stakeholders to observe the cost of procurement targets and perhaps modify them to reflect their social value and cost. ✓ The basic design can be applied in combination with a wide range of approaches described in Section 5. Rather than committing to a single option, the policy makers continue facing a menu of sub-options within the "demand curve framework", which can be refined over time. ✓ Readiness for implementation: by selecting conservative parameters and focusing on services where international experience can be leveraged, the overall framework can be implemented, as a starting point, by 2025.	approach to resource commitment and dispatch, as well as wider practical implementation challenges, which are similar to those described above for reserves (and not repeated here).

Source: FTI analysis

C. Pathway for inertia

7.42 Inertia is not an explicitly procured system service in the NEM. Rather, it is currently provided as a by-product of synchronous generation. If there is a shortfall (short-term, or forecast in the long term), further provision is driven by AEMO interventions (in the operational timeframes) and/or actions taken by NSPs (in the investment timeframes). Its main characteristics are summarised in Figure 7-4 below.

Figure 7-4: Characteristics of an inertia service



Source: FTI Analysis

7.43 In the following subsections we consider the merits of NEM Evolve and the merits of more fundamental design changes to inertia.

C.1 NEM Evolve

7.44 The NEM Evolve approach to inertia would aim to formalise procurement through a non-spot-market mechanism. While recognising that inertia is often (but not always) provided as a by-product of bulk energy, a non-spot-market mechanism would aim to separate out inertia from bulk energy.

7.45 The first step in creating a structured procurement process for inertia is to develop robust and transparent **measurement processes** to enable the SO and market participants to observe inertia levels in RT and to estimate the need for the service ahead of RT. System inertia can already be calculated as the sum of the MWs of inertia from each plant synchronised with the system. Inertia provided by new resources (such as potential future innovative providers of inertia) would also need to be measurable in order to be compensated for providing inertia.[160] While this may seem obvious, being able to define and measure inertia is a pre-requisite to being able to monitor which resources provide the service (and how much they provide), allowing the resources to be appropriately compensated. This ability to measure the amount of inertia provided by each resource would also enable new resources to supply inertia, and underpins the remuneration and penalty regime for the service.

7.46 In addition, **technology eligibility** and technical requirements would need to be defined through the Market Ancillary Service Specification ("**MASS**"), with sufficient clarity for prospective providers to understand how they can contribute to meeting the demand for inertia. In addition to general information regarding the requirements for inertia, the ability of a specific new resource to provide inertia could be assessed as part of the resource connection application process. This approach should be sufficiently flexible to allow for future new entrants with new technologies to be able to contribute to inertia, and thus facilitate innovation. For example, the specification of the service should be able to adapt to incorporate new forms of inertia provision when supported by robust evidence (e.g. simulations, trials, etc).

160 Measurement of inertia is not as straightforward as it may seem. In GB, NGESO has recently entered into a 6-year contract with Reactive Technologies to measure inertia more accurately than has historically been the case. Source: The Energyst, Reactive Technologies signs commercial deal with National Grid to measure inertia (link). Accessed 02/07/2020.

7.47 There are different ways in which inertia could be procured through non-spot-market mechanisms, including:

- **Bilateral forward contracting between AEMO and providers.** This could take the form of procurement through multi-year contracts to give AEMO the confidence that investment in a sufficient volume of resources is undertaken. Conversely, such contracts would give investors the confidence that they will be able to recoup the costs of the investment. These contracts could also include provisions that allow AEMO to schedule the operation of the resources closer to RT to provide inertia. As an initial view, if AEMO was paying for the resources providing inertia, it would be reasonable for it to have the right to commit them[161] (perhaps taking into account the resources' ability to also provide energy and/or other services), although this may not be universally accepted.
- **A structured NSP provision of inertia.** This approach builds on the existing obligation on NSPs to mitigate shortfalls in inertia identified by AEMO by making the process less ad-hoc and more structured. The NSPs could continue having the option of entering into contracts with existing resources to provide inertia, or making necessary investments (such as synchronous condensers) under relevant investment tests. While procurement would be driven by the NSPs (initiated by AEMO's identification of a shortfall), the scheduling of the service and commitment of resources[162] to provide it would likely remain AEMO's responsibility.

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[161] The circumstances in which AEMO might commit a resource might be conditional on defined circumstances (e.g. projected levels of inertia). A self-commitment approach by resources is unlikely to be workable in the context of bilateral forward contracting.

[162] Since there would be forward procurement and no spot market price, this design would be based on centralised commitment by AEMO, rather than the current self-commitment design which is supported by spot prices for energy and FCAS. Different sub-variants of the centralised commitment might be considered, ranging from ones where resources are expected to always respond to AEMO's request to commit; or ones where the circumstances are more limited (e.g. in response to pre-defined triggers). An unlimited obligation for contracted resources to be online at any time AEMO needs inertia is likely to be very expensive.

- **Mandatory technical limits.** This approach would place technical requirements on parties to mitigate shortfalls of inertia. For example, NSPs could be required to maintain a minimum level of inertia on the network;[163] resources could be required to make investments to be able to provide inertia without injecting active power (e.g. generators to operate in synchronous condenser mode); or generating resources could be required to have capabilities that reduced system needs for inertia. This option does not involve any formal procurement or scheduling processes, but it could reduce the need to procure inertia services through the other two options described above.

7.48 A key challenge of providing inertia through any form of forward contracting is that the service is currently provided by committing resources to jointly provide inertia and energy at the same time. If resources "knew" that they are going to be online in a particular dispatch interval in the future, they could offer to provide inertia at a zero marginal cost. Conversely, if resources knew that they were going to be offline, they could offer to provide inertia at a cost that reflects the full start-up, ramp and operating costs (perhaps at a minimum load). However, in practice, resources do not know their future online/offline status. To commit in advance to such forward contracts is a significant risk which would need to be allocated to the resource or to AEMO (on behalf of consumers). In the first case, the resource would risk under-pricing the contract and therefore face losses (which is not sustainable in the long run); while in the second case, the resource would require such high compensation for the risk in bears that consumers would (via AEMO) end up paying too much for the service.

[163] This option differs from the network obligation above in that it places a continuous requirement on NSPs to maintain a technical standard or performance level. In contrast, the previous option (structured NSP provision of inertia) places an obligation on NSPs to take action in response to shortfalls identified by AEMO, which is a discrete (non-continuous) condition.

7.49 One potential approach to forward contracting inertia that has been discussed in the NEM is a contract-for-difference ("**CFD**") mechanism, in which resources that are committed for inertia (subject to ex-post verification) receive an additional payment equal to the difference between a (pre-agreed) strike price and the energy price. This CFD mechanism would thus provide a make-whole payment to resources if the energy price was lower than the price at which the resource was willing to be online (and provide inertia).[164]

7.50 The main attractive feature of the CFD mechanism is that it can provide a risk hedge to both resources and to consumers. Consumers would only pay when inertia needed to be remunerated; while resources would earn a more stable revenue stream by entering into this type of contract (albeit at the cost of reduced upside opportunity from the price volatility). However, in practice, consumers would remain exposed to the significant risk that energy prices might end up extremely low[165] (or even negative), in which case the make-whole payments to resources could be very high. A CFD-type approach to remunerating resources for synchronous services (including inertia, but also system strength and voltage support) is discussed in more detail in Section E on or Power System Security Ancillary Services.

7.51 Additional advantages and disadvantages of procuring and scheduling inertia services through the three mechanisms above are summarised in Table 7-6 to Table 7-8 respectively.

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164 The CFD could be structured in a one-way manner, to provide positive or nil payments to resources; or in a two-way manner, where resources may have to pay back to AEMO in cases energy price exceeds the strike price.
In addition, additional analysis would need to be performed to identify how far ahead time such contracts should be struck. For example, bidders may behave differently if the contracts are agreed closer to RT (e.g. when pre-dispatch information is already available) compared to a situation where the contracts are agreed year(s) in advance.

165 This could occur at times of very high VER output and low synchronous output.

Table 7-6: NEM Evolve for inertia: bilateral contracts

Advantages	Disadvantages
✓ Inertia is no longer provided "for free" as a "by-product" of another service. Resources that enter into contracts are compensated based on the quantum of service provided. ✓ Direct AEMO control over the volume of service procured on a forward basis and scheduling closer to RT (i.e. higher confidence in maintaining system security compared to status quo). ✓ Reduced reliance on out-of-market SO actions. This approach could potentially enable a variety of resources and technologies to compete for contracts to provide inertia and provide margins to support the continued operation of resources able to provide inertia. ✓ AEMO can take attempt to into account the broader characteristics of prospective providers of inertia in selecting the preferred bidder (e.g. contribution to hard-to-measure services such as system strength), but this would require quantifying these other benefits in the competitive evaluation. ✓ AEMO can also take the relevant characteristics into account when scheduling resources.	✗ Very challenging tendering strategy for potential providers of inertia, which may result either in under-pricing of the service (hence resource exiting); or very high offer prices (if a resource prices in the risk of not being online); or the risk of extremely high costs of being online depending on the level of future energy prices. ✗ Significant information requirements for designing the regime, including the need for AEMO to determine procurement targets for inertia, which resources to contract with (and at what price), a governance process for changing procurement process and perhaps modifying contracts over time,[166] a contract remuneration process, a cost recovery approach and the practical implementation. ✗ Appropriate duration, terms and scope of bilateral contracts, and associated penalty regime, can be challenging to determine ex-ante (e.g. shorter contracts give more flexibility to AEMO, and somewhat reduce energy price risks for thermal resources, but could reduce the strength of the investment signal for new resources). ✗ Legacy contracts (particularly if long-duration) can act as a barrier to further innovation and new entrants. ✗ Volume of inertia likely to be suboptimal when procured through a silo approach (e.g. risk of over- or under- procurement) of amount needed in each time period. There is no way for AEMO to specify how much inertia it will need at specific points in time in the future (e.g. at a specific hour on a particular day).

166 The spot-market-based approach can help overcome this challenge as it can adjust market quantities quickly. By contrast a multi-year contract may be considerably less flexible to respond to changes in system needs.

Advantages	Disadvantages
✓ Competitive elements underpinning the bilateral contracts (e.g. auctions) can help provide a price benchmark for the regulated investment approach.	× Design requires that AEMO determine future inertia needs and contract forward to meet those needs. It does not provide a spot market mechanism to elicit additional supply if the resource mix and inertia needs evolve differently than projected by AEMO.

Source: FTI analysis

Table 7-7: NEM Evolve for inertia: structured NSP provision

Advantages	Disadvantages
✓ Inertia is no longer provided "for free" as a "by-product" of another service by resources contracted for by NSPs. Resources contracted for by NSPs are compensated based on the quantum of service provided). ✓ Existing precedent in the NEM for NSP investments in resources that provide inertia. ✓ More transparency and less ad-hoc approach to the NSP obligations (compared to status quo). ✓ AEMO can also take other relevant characteristics into account when scheduling resources (although not when procuring resources, as this is the NSPs' responsibility).	× Resources that do not have contracts with NSPs are not compensated for inertia, and may fail to operate and/or exit inefficiently. × Very challenging tendering strategy for potential providers of inertia, which may result either in under-pricing of the service (hence resource exiting); or very high offer prices to NSPs (if a resource prices in the risk of not being online); or the risk of extremely high costs of being online depending on the level of future energy prices. × NSPs may be naturally biased towards asset-based solutions (compared to contracting solutions), although there may be mechanisms, such as RIT-T, to counter this bias. × High degree of reliance on RIT-T type investment tests, which are unlikely to deliver as much cost pressure as competition would. × Difficulties in maintaining parallel regulated and market-based approaches, as regulated investments are likely to crowd out market-based provision. × Volume of inertia likely to be suboptimal when procured through a silo approach (e.g. risk of over- or under- procurement). × AEMO (in its identification of the shortfall) is required to determine future inertia needs. NSP is then required to take action (investment or contract) to meet those needs. The design does not provide a spot market mechanism to elicit additional supply if the resource mix and inertia needs evolve differently than projected by AEMO.

Source: FTI analysis

Table 7-8: NEM Evolve for inertia: mandatory technical requirements

Advantages	Disadvantages
✓ Existing precedent in the NEM (e.g. MPFR). ✓ Straightforward monitoring and enforcement. ✓ Potential provision of "baseline" contribution towards system security, which can be complemented through contracts / NSP provision (under NEM Evolve) or demand curves (under 'Innovative design', see next section).	× Lack of investment and operational price signals due to the lack of explicit remuneration. × Technical standards are unlikely to work directly for inertia (or indeed system strength), as resources provide the service simply by being online; technical standards can only influence the ability of other network components to operate in a low-inertia environment. × The information requirements for setting technical standards may be high, creating a risk of arbitrary / inappropriate technical requirements being set… × …which could also limit innovation or act as a barrier to entry for new resources. This would ultimately lead to higher costs being incurred, which would need to be recovered (likely from consumers). × This mechanism is unlikely to be sufficient on its own (requires complementary procurement)

Source: FTI analysis

C.2 Innovative design

7.52 It may be possible to set prices for inertia through a spot-market-based approach that relies on a self-commitment approach (Option 3 in Figure 7-1). This would involve setting prices for inertia in RT based on a demand curve and the calculated volume of inertia. This approach would provide a RT price signal to support the commitment or continued online operation of resources providing inertia.

7.53 The concept of using a demand curve to set prices for a service supplied at zero incremental cost has yet to be commonly applied to the pricing of inertia both for the NEM and internationally.[167] However, a demand curve based market design for scheduling and compensating inertia appears to be relatively similar to the design used to price spinning reserves in US markets for 15 years, and therefore is a well-tested design. While resources can submit offer prices to provide reserves in the NYISO day-ahead market, to cover costs such as procuring gas, in RT all resources that offer supply in the RT energy market dispatch provide reserves based on their ramp rate, and are compensated for the reserves provided. Since there are no explicit offer prices for reserves, the RT price cannot be set by the bids. Instead, it is set by either (i) the opportunity cost of the resource being dispatched down out of merit in the energy market to provide reserves or (ii) shortage (penalty) prices if the total quantum of the service was below the target. This same market design framework could be applied to the pricing of inertia in the NEM, as this is a service that also does not have explicit offer prices (for resources that are online).

7.54 The advantages and disadvantages of procuring and scheduling inertia through explicit demand curves are summarised in Table 7-9 below.

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[167] Inertia is not yet a universally procured service by a broad range of SOs (largely because they do not need it yet). We recognise, however, that the WEM is implementing an approach to pricing inertia, through a RoCoF control service. Source: Energy Transformation Implementation Unit, Transformation Design and Operation Working Group Meeting 11, 29 April 2020 (link).

Table 7-9: Demand curve-based provision of inertia

Advantages	Disadvantages
✓ Demand curves for inertia enable the SO to define what it is willing to pay (on behalf of consumers) for any given quantum of inertia, and only pay for the amount provided. ✓ The spot market pricing signal allows AEMO to respond to changing system needs for inertia that it may not be able to accurately project a year (or several years) in advance. Even if some inertia needs were met by forward contracts by the NSPs or AEMO, the spot market signal would be valuable in incentivising the supply of remaining inertia needs. ✓ Competitive provision of inertia is likely to reduce costs relative to non-market approaches. ✓ The provision of inertia could be co-optimised with energy and other relevant services (e.g. reserves and frequency response), which is likely to lead to lower overall costs to consumers. ✓ Much simpler implementation than developing a design for siloed procurement of a service that is provided jointly with energy, operating reserves and FCAS. ✓ An explicit price signal for inertia is likely to send appropriate investment signals and encourage additional providers to enter the market, possibly using different technologies. This should result in lower costs in the long run. ✓ The cost vs quantity trade-offs embodied in the definition of the demand curves will allow regulators and other stakeholders to observe the cost of procurement targets and perhaps modify them to reflect their social value and cost. ✓ The basic design can be applied in combination with a wide range of approaches described in Section 5. Rather than committing to a single option, the policy makers continue facing a menu of sub-options within the "demand curve framework", which can be refined over time.	× Limited international precedent for this approach – NEM would deploy an innovative approach (although there are similarities with RT reserve markets operated by several North American ISOs.) × Potentially challenging requirements for designing the regime, including the need to define the shape of the demand curves, a governance process for adapting the demand curves over time, a remuneration process, a cost recovery approach and the practical implementation (although these factors also need to be considered in the alternative NEM Evolve option). × Risk of volatile prices for inertia (and hence weak investment and/or operational price signals) if the demand curve is too steep, discussed further below this table.

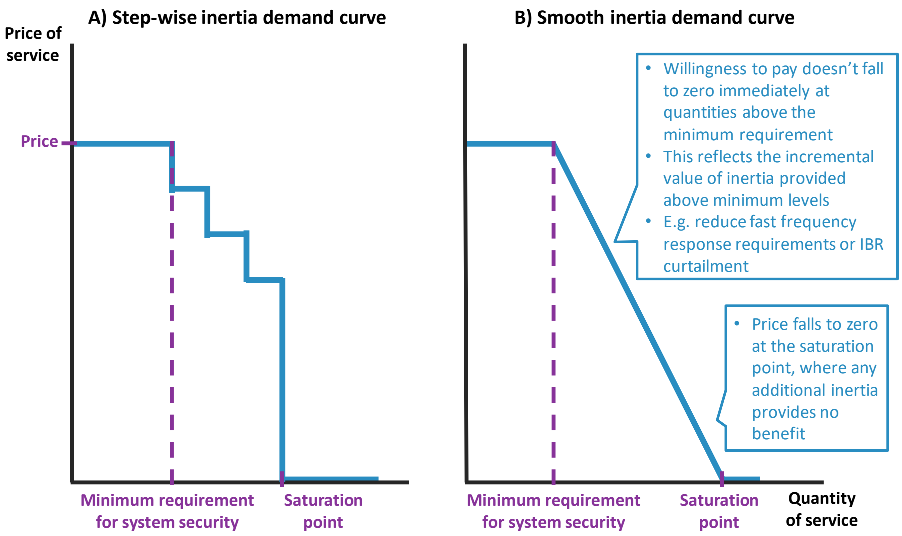
Source: FTI analysis

7.55 To operationalise the concept of demand curves for inertia, AEMO would need to define the quantity of inertia provided by each resource and would need to define a demand curve for inertia, in each relevant region.[168] AEMO could define either a linear demand curve for inertia similar to the ERCOT ORDC or a step function demand curve for inertia similar to the NYISO demand curves for 30 minute reserves. The choice should in part be driven by AEMO market software performance implications which would be explored in discussions with the software vendor.

7.56 A key consideration is that any step function demand curve must have a number of steps so that the commitment of additional resources to provide inertia will reduce the price of inertia but not lead to such dramatic price changes that the commitment will inevitably be uneconomic. We do not consider this to be a disadvantage of the model (hence it is not included in Table 7-9 above), but it is an important pre-requisite to use the concept of demand curves in a self-commitment model for resources.

7.57 Two types of stylised demand curves for inertia are presented below in Figure 7-5: the first one is a step-wise demand curve, while the second one is a smooth function.

Figure 7-5: Illustration of step and smooth demand curves



Source: FTI analysis

168 The relevant regions could be the individual NEM regions, but demand curves could also be defined for subregions within the NEM regions if this were appropriate from the standpoint of system needs.

7.58 Such a demand curve based pricing design for inertia would send a RT spot market price signal that would support self-commitment decisions consistent with the current NEM design, with market participants able to provide inertia, taking into account energy, reserve and inertia revenues in making commitment decisions.

7.59 The value of the incremental inertia above the minimum requirement would reflect several considerations:

- The minimum target is based on offline studies that will necessarily be an imperfect description of actual system conditions. Although the target can be defined conservatively, there is a degree of uncertainty regarding actual inertia needs at any point in time;
- The potential for a shortfall in the supply of inertia as a result of resources tripping offline unexpectedly (unless there is a supply margin); and
- The need for inertia could change over time as a result of changes in intermittent resource output.

7.60 The definition of the demand curve could be refined further:

- **For the cap of the demand curve**: AEMO could develop a more detailed understanding of the minimum levels of inertia required across the NEM, with potential geographical (or temporal) granularity, and the associated price cap. As explained earlier in this section, the price cap could be tied to a multiple of the value of lost load, or otherwise linked to the cost of the next-best alternative action that AEMO would take to prevent the system from operating close to a point of collapse.
- **For the slope (or the steps) of the demand curve**: AEMO could examine the monetary value (if any) associated with procuring volumes of inertia beyond the estimate minimum requirements. As explained earlier in this section, the value of incremental inertia could relate to the ability of the system to operate at higher levels of VRE, increases in system security, or avoiding costly out-of-market actions by AEMO. It could also relate to the ability to avoid shortfalls as a result of resource outages, and to accommodate the need of thermal resource to go online or offline in response to changes in load. In addition, the design should also consider the interactions of inertia with frequency response targets and identify any relevant trade-offs between procuring the two services (if indeed, as is implied here, there is an interest in co-optimising inertia with frequency response).

7.61 The shape of the inertia demand curve is particularly important given that the supply of inertia is “lumpy”. As discussed above, it is important that the demand curve is sufficiently graduated to ensure that the inclusion of a small amount of additional resource does not make the price collapse.

7.62 If the demand curve was not sufficiently graduated (see Figure 6-3 above), the outturn price for inertia, formed through the intersection of demand and supply curves, could be excessively volatile and unpredictable, as well as too sensitive to small surpluses in the supply of inertia, from the perspective of market participants. In the absence of a sufficiently graduated demand curve, the creation of a RT spot market price signal that would support both investment and/or operational unit commitment decisions would be challenging (and might even be unworkable), which could indicate a preference for a non-spot-market approach to procuring and scheduling inertia.

7.63 The design of the demand curves for inertia could be relatively conservative initially, with relatively high levels of minimum requirements and a high “saturation point” (i.e. a relatively larger procurement of inertia above the minimum target). However, the design should be set up flexibly such that the demand curve parameters (cap, slope and saturation point) can be amended in the future and shifted or re-shaped as required to meet market and transmission system needs efficiently. An important advantage to starting with a spot market-based approach, relative to starting with forward contracts, it that the spot market design could be readily modified over time as AEMO’s needs change, with perhaps a future transition to some degree of forward contract when system needs are well understood based on several years of operating experience under the spot market design. The trade-off between the flexibility and stability of the procurement regime (in relation to investability) is discussed in Section 8.

7.64 The design would include a remuneration process for the service, which would be determined by the demand curve described above. Unlike the current NEM design, in the proposed model all resources providing inertia would be explicitly remunerated for the service based on the price at the demand and supply curve intersection. A key benefit of the demand curve design is that it would enable a price to be set for the service independent of resource bids (i.e. if there is no offer price for inertia because the marginal cost of providing the services by a resource that is online is nil, as discussed in ¶6.35 above).[169]

[169] A bidding system for inertia is unlikely to work since resources provide inertia by being online; and so they cannot “not provide” the service once they are online.

7.65 The **cost recovery** process should ideally follow the "causer-pays" (or, as an alternative, the "beneficiary-pays") principle. This is particularly important to define for levels of inertia that go above the minimum system requirements. One option would be to consider a partial smearing of the costs across network users combined with a partial allocation of the costs to VRE insofar as they drive the need for inertia.

7.66 Finally, the **implementation process** itself would need to be identified. One option is to take a conservative approach:

- First, AEMO could test initial demand curve concepts against historical commitment data to assess how they would have performed; and
- Second, AEMO could test the inertia demand curve concept through a **phased process**, for example by applying it within a single NEM region where the need to incentivise the supply of inertia within the market is most acute. This would enable both AEMO and market participants to gain experience and identify learnings prior to roll-out to other NEM regions as/when needed.

7.67 Importantly, if spot-market-based procurement of inertia was the long-term objective of the NEM market design, then the design of other (non-inertia) services should be developed with a vision of inertia becoming part of the overall ESS suite in the long run. This means that, for example, the co-optimisation software should already have the functionality built in for inertia demand curves, albeit with this potentially being "switched off" in the initial years.

D. Pathway for system strength

7.68 System strength is not an explicitly procured system service in the NEM. Rather, it is provided as a by-product of synchronous generation. If this results in a shortfall, further provision is driven by AEMO interventions (in the operational timeframes) and/or actions taken by NSPs (in the investment timeframes). Its main characteristics are summarised in Figure 7-6 below.

Figure 7-6: Characteristics of a system strength service

Definition and measurability	A system strength service is very difficult to define and measure accurately. It is often a by-product of other services.	
Scope for competition	Narrow scope for competition as the service is typically localised.	
International experience	Little to no international precedent for the procurement of a system strength service.	
Scope for co-optimisation	Uncertain potential for co-optimisation with bulk energy and other ESS due to the lack of measurability and its 'by product' characteristics.	

Legend Highly favourable to spot market-based ESS; Somewhat favourable to spot market-based ESS; Not favourable to spot market-based ESS

Source: FTI analysis

7.69 In the following subsections we consider the merits of NEM Evolve option and the merits of more fundamental design changes to system strength.

D.1 NEM Evolve

7.70 The NEM Evolve approach to system strength would aim to formalise the procurement of system strength through a structured mechanism. Currently, system strength is typically provided as a by-product of other features of the power system and it could be characterised as an *outcome* of the power market setup rather than a service.

7.71 As explained in Section 2, the key challenge with system strength is that it does not have an easily measurable dimension or units, which means that it is currently not possible to take direct action to procure or schedule a specific quantum of the service (e.g. "three units of stable voltage waveform"). Instead, in response to system strength shortfalls, AEMO (or NSPs) take actions that increase some specific aspects of system strength, for example by bringing synchronous resources online, or by investing in synchronous condenser capacity.

7.72 Given the difficulties in targeting the multifaceted nature of system strength, these actions tend to be ad-hoc and therefore risk being inefficient: for example, the cost of delivering a given level of system strength may be higher than is in the interest of consumers. Moreover, the by-product approach to system strength means that resources are not explicitly compensated for the value they provide, leading to weak operational and investment price signals, which is likely to increase the costs of the service even further in the long run.

7.73 A structured mechanism would aim to improve on this approach by structuring how system strength is procured, scheduled and compensated.

7.74 The first step in structuring this type of process for system strength is to develop robust and transparent processes to enable the SO and market participants to observe the need for system strength (demand) and how it is met through specific actions or from specific resources (supply).[170]

7.75 On the demand side, the Transfer Limit Advice tables[171] recently published by AEMO are an initial attempt at formalising the need for system strength: they indicate the combinations of resources that AEMO typically draws on to maintain a stable system (see Box 2-1 in Section 2). To improve procurement and scheduling of system strength, the TLAs could be expanded to:

- Articulate the principles that drive AEMO's views on which specific combinations of resources it would direct on under different circumstances. This would improve the operational and investment signals by, for example, helping market participants understand whether/when AEMO might schedule additional resources to provide system strength in order to prevent VRE curtailment, or whether/how AEMO might take into account the resources' technical characteristics in deciding which resources to schedule.[172] While we recognise that AEMO already publishes the TLA tables, this step would improve the status quo by providing more clarity on how these tables are used in practice.

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170 If AEMO was able to define this accurately, then this would also enable the demand curve concept to be operationalised. This is discussed in Section D.2 Innovative design below.

171 AEMO, Transfer Limit Advice – System Strength, February 2020 (link).

172 For example, it is unclear whether AEMO currently has a preference for utilising combinations of resources that have shorter on/off times, or a lower minimum stable load. It is also unclear over what timeframe AEMO makes these decisions – e.g. hour ahead, day ahead or longer periods, and how the growing penetration of IBR influences these decisions.

- Set out how new resources, e.g. those that can provide system strength without injecting power, could become part of the range of combinations of resources that AEMO relies upon. This would be important to mitigate the potential perception that AEMO would tend to call on "tried and tested" resources and might be reluctant to rely on new (or innovative) approaches.[173] This would be important under all options considered for system strength.
- Define the amount of system strength provided by each resource to enable AEMO to pay appropriate compensation for resources that provide system strength. This would provide a transparent and efficient signal, rewarding resources for providing a valuable service, and would be an improvement on the ad-hoc directions (or NSP regulated investment) that the NEM has historically relied upon. Crucially, this approach requires the SO to determine how the compensation would be set, which resources (and how much) would receive it and what the penalties for non-delivery might be. This would be particularly challenging in the context of forward contracts, in which it would be necessary to base compensation on the amount of system strength that the resource would provide under a variety of future system conditions.
- Publish ex-post information on which combinations of resources are utilised at what times and how they have been compensated.[174] This would provide investment signals as market participants would understand, locationally and in terms of frequency, which resources tend to be utilised most frequently, and therefore where additional investment is likely to be most valuable. For new entrants, the information might also provide an indication how much revenue they may expect to receive for providing system strength, which they would be able to factor into investment decisions.

[173] This is not a sufficient condition. Market participants also need to face an adequate price signal in order to have an incentive to enter.

[174] The appropriate granularity of this pricing information may need to be considered further, as there may be commercial sensitivity around this, particularly if some of the compensation is targeted at a small number of market participants who may have a degree of local market power.

7.76 On the supply side, technology eligibility and technical requirements would need to be defined through the MASS (or elsewhere, such as the NER, as appropriate), with sufficient clarity for prospective providers to understand how they can contribute to meeting the demand for system strength. As with inertia, this approach should be sufficiently flexible to allow future new entrants with new technologies to be able to contribute to system strength, and thus facilitate innovation. For example, the specification of the service should be able to adapt to incorporate new forms of system strength provision when supported by robust evidence (e.g. simulations, trials, etc).

7.77 This is particularly important for system strength service because it is likely to be in consumer interest that current resources and future technologies are able to provide specific, targeted capabilities to support different facets of the service. If, in the future, the need for system strength service were to be differentiated into its underlying components (e.g. fault current, short circuit ratio, voltage wave form provision/stabilisation, etc.), this would help crystallise the different volume demand for the individual components (e.g. on a temporal or geospatial basis). Prospective providers, including future technologies, would then be in a position to target the provision of specific components of system strength[175] and potentially reduce the total cost of ensuring system security.

175 For example, certain elements of "system strength" may in future be provided by grid forming inverters, potentially at a lower cost than synchronous machines. These grid forming inverters can contribute to stabilising voltage waveform, but may not contribute fault current. These grid forming inverters could thus play an important role in reducing system costs if in the future, as IBR penetration increases, the stabilisation of voltage wave form was the most important service required.

7.78 There are different ways in which system strength could be procured through non-spot-market mechanisms, including:

- **Bilateral forward contracting between AEMO and providers.** This could take the form of procurement through multi-year contracts for resources to come online when instructed to do so by AEMO. The aim would be to give AEMO the confidence that services can be delivered from existing units (from shorter, say 3-year contracts), or even that investment in a sufficient volume of resources is undertaken (which may require much longer, and potentially expensive, contracts).[176] These contracts could also include provisions that allow AEMO to schedule the resources closer to RT to provide system strength. This approach would require AEMO to specify the amount of system strength each resource would provide, in order to evaluate which resources to contract with. AEMO would also need to determine how much system strength it would need to contract for over the relevant horizon.

[176] AEMO may either attempt to contract forward to meet all system needs, or only part of the system needs. In the latter case, AEMO may contract with resources that would have been online anyway (as those resources would be able to provide a more competitive offer). As a result, AEMO may also need a complementary mechanism to commit other resources (i.e. those not bilaterally contracted with) in RT.

- **A structured NSP provision of system strength.** This approach builds on the existing obligation on NSPs to mitigate shortfalls in system strength identified by AEMO by making the process less ad-hoc and more structured (and thus helps avoid the potentially high costs of AEMO taking actions to mitigate the shortfall closer to RT). This approach falls within the existing NSP planning processes and can thus provide benefits of economies of scale as well as scope.[177] In this approach the NSPs could continue to have the option of entering into contracts with existing resources to provide system strength, or making necessary investments (such as synchronous condensers or line augmentations) under relevant investment tests. While procurement would be driven by the NSPs (initiated by AEMO's identification of a shortfall), the scheduling of the service would likely be AEMO's responsibility.
- **Mandatory technical limits.** This approach would place technical requirements on parties to mitigate shortfalls of system strength and reduce the minimum level of system strength required by the party to operate: for example, new resources may be required to invest in inverters that are able to maintain stable operation in an environment of lower system strength. This option does not involve any formal procurement or scheduling processes, but it would likely reduce the need for AEMO (or NSPs) to take actions to mitigate shortfalls.

7.79 The advantages and disadvantages of procuring and scheduling system strength services through the three mechanisms above are summarised in Table 7-10 to Table 7-12 respectively. The three mechanisms are not, however, mutually exclusive, and a combination of the three solutions may be explored, to identify an optimal solution.

Table 7-10: NEM Evolve for system strength: bilateral contracts

Advantages	Disadvantages
✓ System strength is no longer provided "for free" as a "by-product"	× Significant information requirements: AEMO needs to determine how much system strength to contract for to meet future needs, the

177 The economies of scope arise both among different ESS, as well as between ESS and wider investments undertaken by NSPs. On the first one, NSPs may be in a position to capture, within their planning processes, the fact that the same equipment can often provide multiple services, including system strength, inertia and reactive support. On the second one, there are potential economies of scope for NSPs in co-optimising the solutions to system strength issues and network augmentations: this is because system strength needs can be partially mitigated by reducing system impedance, which can in turn be enhanced through an upgrade of network lines.

Advantages	Disadvantages
of another service. Resources that enter into bilateral contracts are compensated based for the quantum of service provided (this may initially be a proxy, e.g. their contribution to fault level). ✓ Direct AEMO control over the volume of service procured on a forward basis and scheduling closer to RT (i.e. higher confidence in maintaining system security compared to status quo). ✓ Reduced reliance on out-of-market SO actions. This approach will thus enable a variety of resources and technologies to compete for contracts to provide system strength and provide margins to support the continued operation of resources able to provide system strength.	amount of system strength each resource should be compensated for providing, and which resources to contract with, at what price, etc. × Requirement to expand significantly on the information currently provided in the TLAs (noting that these tables have only been formulated recently), including the principles for scheduling, the ex-post compensation, *etc* (see above in the main body of the report). × Potential market power concerns for specific market participants (which may require additional market power control tools such as regulation or price capping) × Appropriate duration, terms and scope of bilateral contracts, and associated penalty regime, can be challenging to determine ex-ante (e.g. shorter contracts give more flexibility to AEMO, and somewhat reduce energy price risks for thermal resources, but could reduce the strength of the investment signal for new resources). × Conversely, legacy contracts (particularly if long-duration) can act as a barrier to further innovation and new entrants. × Volume of system strength likely to be suboptimal when procured through a silo approach (e.g. risk of over- or under-procurement). × Separate procurement of system strength, which is provided jointly with energy, FCAS and reserves may not be workable and has the potential for extremely high network user costs. × This design requires AEMO to determine future system strength needs and contract forward to meet those needs. It does not provide a spot market mechanism to elicit additional supply if the resource mix and system strength needs evolve differently than projected by AEMO.

Source: FTI analysis

Table 7-11: NEM Evolve for system strength: structured NSP provision

Advantages	Disadvantages
✓ System strength is no longer provided "for free" as a "by-product" of another service by resources contracted for by NSPs. Resources contracted for by NSPs are compensated based on a suitable proxy for the quantum of service provided. ✓ Existing precedent in the NEM in NSP investments in resources that provide system strength. ✓ More transparency and a less ad-hoc approach to the NSP obligations (compared to status quo). ✓ May facilitate co-ordination of the provision of system strength with other services provided by NSPs (e.g. solutions that also provide inertia and reactive support); and co-ordination with other ways of enhancing system strength (e.g. co-ordination of inverter control responses, and transmission line build out to reduce impedance.	× Resources that do not have contracts with NSPs are not compensated for system strength and may fail to operate and/or exit inefficiently. × Significant information requirements: in response to AEMO shortfall identification, NSPs need to determine how much system strength they should contract for to meet future needs, determine the amount of system strength each resource should be compensated for providing, and determine which resources to contract with, at what price, etc. × NSPs may be naturally biased towards asset-based solutions (compared to contracting solutions), although there may be mechanisms, such as RIT-T, to counter this bias. × Potential market power concerns for specific market participants (which may require additional market power control tools such as regulation or price capping). × Risk of market participants investing in assets that become stranded if NSPs undertake regulated investments that displace the need for the non-regulated resources. × Risk of uneven playing field between regulated investments (by NSPs) and resources that are not compensated for system strength through contracts with NSPs, leading to inefficient scheduling. × High degree of reliance on RIT-T type investment tests, which are unlikely to deliver as much cost pressure as competition would × Volume of system strength likely to be suboptimal when procured through a silo approach (e.g. risk of over- or under- procurement). × Separate procurement of system strength, which is provided jointly with energy, FCAS and reserves may not be workable and has the potential for extremely high network user costs. × Design requires AEMO to determine future system strength needs and identify shortfalls, which then obligate NSPs to take action (invest or contract with resources) to meet those needs. It does not provide a spot market mechanism to elicit additional supply if the resource mix and system strength needs evolve differently than projected by AEMO.

Source: FTI analysis

Table 7-12: NEM Evolve for system strength: mandatory technical requirements

Advantages	Disadvantages
✓ Existing precedent in the NEM (e.g. "do no harm" requirements[178]). ✓ Requirements on resources to operate in a low system strength environment can reduce the need for system strength (but the merit of this approach depends on the associated costs). Examples could include more onerous access standards, coupled with the ability to co-ordinate inverter control responses. ✓ Can encourage the adoption of new technologies (e.g. grid-forming inverters) ✓ May provide the basis for the development of new markets: for example, mandating voltage wave form stabilisation capability could encourage adoption of this capability, to be remunerated if/when a market for this service is developed. ✓ Easier monitoring and enforcement compared to a market-based option. ✓ Potential provision of baseline contribution towards system security (minimum system requirements). ✓ It may be possible to set requirements that reduce system strength needs and avoid the interconnection of resources that would unduly increase system strength needs, (however, it is not possible to avoid the need to procure <u>some</u> system strength by committing some type of synchronised resource).	✗ Lack of investment and operational price signals due to lack of explicit remuneration. ✗ The information requirements for setting technical standards may be high, creating a risk of arbitrary / inappropriate technical requirements being set… ✗ …which could also limit innovation or act as a barrier to entry for new resources (although we recognise that, as set out on the left, technical standards can help prevent poorly performing technologies from unduly increasing the overall system strength needs). ✗ No signal for procuring additional system strength over and beyond the minimum system requirements (e.g. to facilitate additional VRE deployment).

Source: FTI analysis

178 As discussed in ¶2.54.

7.80 On balance, based on the advantages and disadvantages of the various approaches in the tables above, it is possible that a non-spot-market-based approach to procuring and scheduling system strength might be preferable to the current ad-hoc intervention-based approach in the NEM if it were possible for AEMO to measure the system strength provided by different resources and project future system strength needs.[179] While technical standards could potentially be used to reduce future system strength needs and avoid the interconnection of resources that would unduly increase system strength needs, it does not appear that current technology would enable technical standards to completely eliminate the need for other resources to provide some system strength. We also recognise that the provision of system strength is being addressed by AEMC through its review process.[180]

7.81 Nevertheless, there are a number of issues that would need to be resolved to implement a non-spot-market-based approach for the procurement and scheduling of system strength, including:

- Policy makers would need to set up a transparent approach to setting the **minimum technical requirements** for system strength which adequately reflect the system integrity needs and express them in observable and measurable units.[181]
- The preferred non-spot-market approach would need to make an **efficient use of existing synchronous resources** in the short to medium term (prior to their closure). This would require appropriate trade-offs being made between new investments (whether regulated by NSPs, underpinned by contracts with AEMO, or mandated by technical standards) and their interaction with existing resources (e.g. potential acceleration of early closures).

179 The spot-market-based approach is explored in the following subsection, where we show that such an approach is highly challenging to implement in the near future.

180 AEMC, Investigation Into System Strength Frameworks in the NEM, 26 March 2020 (link).

181 These units could be related to the various facets of system strength that are beneficial for the system. As discussed in Section 2, some of the currently available proxies include fault current and the short circuit level.

- The structure of the **remuneration** for resources, which could vary in terms of the quantum (e.g. different levels of payment for resources' contribution to the minimum system requirements, versus their contribution to additional above-minimum needs), or in terms of the type of service (reflecting the different aspects of the multi-faceted system strength[182]). In any event the remuneration approach would need to reward the provision of system strength both by existing resources (e.g. synchronous generation) and any new potential providers,[183] for example through ex-ante availability contracts that AEMO could call upon, or through a cost of service approach (with an appropriate return). Moreover, the forward contracting approaches require a forward-looking basis for defining both system strength needs and measuring the contribution to system strength provided by each resource, potentially over a variety of system conditions.
- There would be challenges in **defining contractual requirements**. There would need to be rules defining the obligations of the different resources to provide system strength (e.g. how often they would be obligated to come online) in order for resources to be willing and able to submit offers. An unlimited obligation for all resources to be online at any time AEMO needs system strength would likely be very expensive. The different obligations would need to be taken into account in the contracting and pricing process.
- There would need to be a **residual mechanism** for procuring system strength in addition to that identified by forward projections and covered by forward contracts. This would be required in case the actual needs for system strength differed from the projections that underpinned the forward contracts.
- The approach to **market power mitigation**, which is likely to arise at least in some cases given the highly locational nature of the service. Some options for this could include the use of price caps or penalties for unjustified behaviour, with particular attention paid to "pivotal suppliers".

[182] The fact that system strength has multiple facets means that a single technology may not be best suited (or cost efficient) in all circumstances. A more granular articulation of system strength needs might help reduce costs of its provision by enabling the supply of the service to be better matched to the needs. See also footnote 175.

[183] If the reward was offered only to new resources, this would lead to an uneven playing field and would likely distort the operational decisions of existing resources and could even unduly accelerate closures.

- The **interaction between system strength and other services** (notably inertia, reactive support and energy) would also need to be considered, given that system strength is often (though not always) provided simultaneously with other services. This is a major issue that is likely to raise concerns similar to those discussed in the previous subsection on inertia, but that could be even more challenging. This would need to be considered both for the procurement and scheduling of system strength.
- There may be a degree of **competition** between existing resources, new prospective entrants (from market participants investing in synchronous resources) and regulated resources to provide system strength. The detailed market design would need to appropriately reflect the risk that regulated investments (or technical standards) may lead to undesirable outcomes. This includes the risk of a market participants' assets becoming stranded if revenue levels do not meet expectations at the time of investment due to a subsequent (and unexpected) construction of a regulated asset.

D.2 Innovative design

7.82 While the extension of the demand curve concept to the pricing of inertia appears a relatively small step from the NYISO's historic use of demand curves to set RT reserve prices, a bigger step would be involved in using a demand curve design to price system strength. A key complication is that AEMO can measure the inertia provided by a resource and hence compare the amount provided against the willingness to pay based on a demand curve. By contrast, system strength is not, currently, defined and measured in a way that would enable market-based procurement and scheduling of the service. As set out in the previous subsection, AEMO is able to partially express the need for the service through the TLAs, but it is currently not possible to articulate a demand curve in specific units, e.g. as "three units of stable voltage waveform for $100".

7.83 Nevertheless, we consider it appropriate to lay out a transition path to implementing a demand curve based approach to the procurement and scheduling of system strength. It is important to note that most or perhaps even all of the challenges to implementing such a spot market design also apply to implementing the forward contracting designs described above (whether through AEMO or NSPs). Moreover, it is likely to be much less difficult to address these challenges in the context of the spot market for the current operating day than with projected needs and capabilities that would extend a year or more into the future.

7.84 The following paragraphs set out the steps required for a transition path to implementing a demand curve based approach to the procurement and scheduling of system strength:

7.85 First, the analysis in the TLA Paper (which we recognise has been formulated only very recently) would need to be expanded to **create a comprehensive combination of resources** that could be called upon to deliver the minimum requirements for system strength. The TLA Paper currently reflects a limited number of resource combinations that work in practice, but these combinations are incomplete, and it is unclear whether there is a systematic, structured and standardised process behind the tables that also encompasses the potential inclusion of new (future) resources. This requirement is in common with the requirements for the forward bilateral contract approach described earlier, but it would be simpler in that it would only need to address current system conditions, rather than system conditions a year or more in the future.

7.86 Second, the **remuneration process** for the provision of system strength would be developed, based on $ payment per unit of system strength. However, at this stage, the appropriate measurement units have not been defined, and there appear to be significant challenges associated with the development of a spot market for system strength.[184] This requirement is also in common with the requirements for the forward contracting approaches described earlier, which would also need to measure the contribution of each resource to meeting system strength needs. This requirement would be simpler to achieve for the spot market design as it would not need to project the future contribution of each resource to system strength under potentially different system conditions.

184 AEMO, Investigation into system strength frameworks in the NEM Discussion Paper, 26 March 2020 (link), pages 30, 31 & 33.

7.87 Third, a comprehensive study of system strength requirements would be undertaken in order to develop a clear understanding of the **value of different units** and their contribution towards (i) minimum necessary requirements; (ii) higher system security; (iii) ability to sustain higher penetration of IBR; and/or (iv) the maximum quantum of system strength that AEMO is willing to pay for. This information would be necessary to define the shape of a demand curve for system strength: the minimum requirement and the associated maximum price, the slope of the demand curve and the saturation point. The requirement to understand the value of different units is in common with the forward contracting approaches described earlier, which also need to measure the contribution of different units to the four issues listed above. The forward contracting approaches would be somewhat more complex, as they would not only need to make this assessment for the current system conditions (as is the case for the spot market approach) but also for future system conditions.

7.88 Fourth, the shape of a "demand curve" for higher levels of system strength would need to be determined. This could be analogous to the definition of the demand curve for inertia in excess of the minimum discussed in the previous section. This evaluation would consider the benefits of having additional system strength:

- in the event resources providing system strength trip offline or need to go offline;
- in the event of variations in intermittent resource output; and/or
- to prevent IBR curtailment.

7.89 It appears likely that the same need would arise under the forward contracting approaches, which would need to assess how much AEMO would pay for additional system strength over the term of the contract.

7.90 On balance, it would likely be more workable to begin by implementing a spot market for system strength and potentially transitioning to some degree of forward contracting for system strength after the spot market had been in operation for a few years.

7.91 A key step in this transition path would be to distinguish between the different types of requirements for system strength (i.e. what drives the need). For example, the TLA tables published by AEMO already express the requirements for system strength and the ability to support different IBR penetration levels.[185] We recognise that the quantification of how system strength can support higher levels of VRE penetration is a topic of current research. The two types of requirements for system strength are discussed in Box 7-1 and Box 7-2 below, which aim to set out the potential areas of research and analysis that might be explored further in the context of a live research topic.[186]

Box 7-1: System strength to support higher VRE

AEMO's existing TLA tables present combinations of units required to deliver minimum system strength in South Australia. In these tables the system strength requirement depends in part on the level of VRE output. However, we recognise that the TLA tables have only recently been formulated by AEMO.

It appears to us that AEMO could explore how these tables could potentially turned into relationships that define the limit on VRE output in terms of system strength, as reflected in the unit commitment and TLA tables. The remainder of this box sets out some initial thinking in this direction, which could be explored in more detail.

AEMO could extend the existing tables to reflect the change in allowable VRE output from having each resource online, and pay online resources a price reflecting the change in allowable VRE output due to their operation, times the shadow price of the VRE output constraint. The change in the value of the shadow price with increasing levels of allowed VRE would in effect define a demand curve for system strength. If the constraint on VRE output were not binding, as it might be during night time hours with low wind output, the shadow price of the constraint would be zero, and there would be no payments for greater system strength to support VRE output.

The shadow price of the VRE output constraint could be posted in RT and projected in AEMO NEMDE runs. If the change in maximum VRE output associated with each unit is relatively stable this figure could be computed in advance for market participants to take into account in their unit commitment decisions. If the change in maximum VRE output depends on which other resources are online or other factors, this change in the maximum output figure could be projected for each resource in RT.

185 AEMO may in the future identify additional types of needs for system strength, resulting in the definition of additional combinations of resources to meet demand for system strength, and creating the need for the definition of additional demand curves.

186 We also note that the challenges raised in relation to system strength arise in the forward contracting approaches discussed earlier. For example, if AEMO were not able to articulate and quantify the needs for system strength to support higher levels of VRE, this would make it challenging to assess what resources AEMO should enter into forward contracts with.

Such a design would require AEMO to calculate the change in maximum VRE output associated with all units, rather than just a few units, but it should be doing that in any case in a non-discriminatory market. This would potentially be another benefit of implementing a market for system strength. In addition, operators of new types of resources able to provide system strength for the purpose of increasing VRE output could request that AEMO study the contribution of their resource to increased VRE output under different system conditions to inform their investment decisions.

The demand curve for system strength to support VRE output would set a price that could be taken into account by resource operators consistent with the NEM's self-commitment design.

These evaluations are not specific to the demand curve based approach. Rather, the same evaluations would also need to be carried out in order to implement the approaches based on forward contracting. Importantly, it appears to us that the forward contracting evaluation would be far more complex, as it would need to project future needs for system strength to accommodate higher VRE output, set compensation, and evaluate the cost of alternative resources in meeting the projected needs. It would appear much more workable to begin by carrying out such an evaluation for current RT conditions and at some future point in time consider forward contracts.

Box 7-2: System strength to support minimum system requirements

The most difficult design element for system strength demand curves will be the pricing system for the minimum level of system strength needed to support secure operation of the transmission system. These minimum system strength requirements for South Australia and Victoria are currently expressed by AEMO in the TLA tables, with the required unit commitments depending on the level VRE output in the case of South Australia and on imports in the case of Victoria.[187]

In defining a demand curve to incentivise resource commitments to meet minimum system strength requirements AEMO needs to in some manner define both (i) how much an additional unit contributes to system strength; and (ii) what is the value of additional system strength beyond the minimum.

The remainder of this box sets out some initial thinking in this direction, which could be explored in more detail. As with the previous box, however, we note that these issues are not specific to the demand curve-based approach. Rather, the same need would exist under the forward contracting approaches described earlier, which would also need to define minimum requirements specify the value of system strength beyond the minimum. These requirements would be much simpler to define for the spot market design as spot market requirements could be defined based on current system conditions and needs rather than requiring that AEMO project the future needs for system strength under potentially different future system conditions.

187 See AEMO, Transfer Limit Advice, System Strength, February 2020 (link), Table 3.

The high level premise of a demand curve for the minimum system strength requirement is that the price should get very high as the system strength falls closer to the minimum and fall as system strength rose to the point that the system could withstand the loss of a number of the resources contributing to system strength while continuing to meet the minimum. One can turn this standard around and frame it in terms of reflecting the willingness of system operators to take increasingly expensive actions to maintain system strength as system strength falls toward the minimum.

We understand that it will not be possible to precisely define the contribution of each resource to system strength nor to define a precise demand curve measuring increasing system strength. However, it might be possible to define both contributions and demand curves in a manner that is roughly accurate, so that a market could be coordinated based on these approximate definitions with the system operators having the ability to make adjustments at the margin when necessary, but with the intent the these ad-hoc operator actions with be the anomaly rather than the rule.

As observed above, the same need to define the contribution of individual resources would also exist under a forward contracting based approach, with the added complexity of needing to define contributions under a variety of future conditions.

One way to start the process of defining resource values would be to use the current minimum strength TLA tables. The process could be as follows:

i. Associate a parameter value αi with each resource in the TLA tables;

ii. Formulate the equation $\sum \alpha i * Vi \geq 1$

    where $Vi = 1$ if resource I is online in the nomogram and $Vi = 0$ is it is not.

iii. Combinations of resources in which the system strength requirement also depended on VRE output could be similarly expressed as equations of the form:

    $\sum \alpha i * Vi + \beta \, Qvre \geq 1$

    Where Qvre is the maximum VRE output

iv. Solve for the set of αi that is most consistent with the TLA tables.

In carrying out this analysis AEMO might need to fill out the TLA tables with additional combinations of resources that would satisfy the minimum system strength requirement in combination with levels of VRE imports.

The equations including VRE output might also be used to inform the value of resources in supporting increased levels of VRE output.

If this methodology yielded a set of values for αi that were reasonably consistent with operator judgement and the TLA Tables, then this model could be used to define demand curves for system strength. Specifically, with such a model, the estimated values of αi could be used to define a demand curve in terms of levels of system strength that were X% above the minimum (as measured by $\sum \alpha_i * V_i$, X% above and draw a demand curve from a high price at the minimum down to a price of zero for a large excess. AEMO judgment could be used in defining the initial level for a zero value, with refinements possible over time as AEMO and stakeholders gain experience with the design.

Since this would be a new process, it would seem beneficial to use this approach to setting spot prices and values for a period of time before using such an approach to determine payments under a long-term contract (the latter could be difficult to change as AEMO gained experience with the market).

7.92 The values of the demand curve shape parameters are likely to vary on a geographical basis, given the location-specific nature of system strength, giving rise to “local” demand curves (which, in turn, are likely to be a function of the degree of penetration of IBR in that location, as well as the levels of impedance in the local network). The values could also vary depending on RT system conditions, and therefore could be time dependent.[188]

7.93 On balance, it appears that there are short to medium term challenges to procuring and scheduling system strength using a demand curve approach which would need to be resolved prior to progressing the concept further. However, these same issues would need to be resolved in order to implement the forward contracting approaches and the complexity would be much greater under the forward contracting approaches due to the need to specify the requirements well in advance (and under a variety of future conditions). This contrasts with the spot market demand curve, where issues would only need to be addressed at the RT horizon.

7.94 However, if and when the demand curves for system strength have been expressed in a sufficient amount of detail, it may be possible to consider a market-based approach (using demand curves) for system strength. At that point, it would also be important to consider additional issues:

- The approach to co-optimisation of procurement and scheduling of system strength with other ESS (and the potential interaction with ahead-markets);

[188] We observe that this challenge would also arise in the forward contracting approach discussed earlier. In particular, it would be difficult under a forward contract approach to structure obligations and payments for system strength needs that varied with RT system conditions.

- **Mixed approaches**, where minimum levels of system strength are provided through non-market arrangements, while above-minimum system strength (e.g. to facilitate higher IBR penetration) is provided through market-based arrangements. This could be a promising way forward in circumstances where a regulated investment was preferred to deliver the minimum system requirements;
- The need for **location-specific demand curves** for system strength (as region-wide curves may not adequately reflect the granularity of need for the service). This may in turn lead to challenges associated with local market power: if the demand curves are specified for very limited geographical ranges, this may severely limit the range of prospective suppliers and thus reduce the potential benefit of competitive supply of the service (and/or raise power market issues that would need to be addressed); and
- A **cost-recovery mechanism** (e.g. causer-pays or beneficiary-pays), where potential options include smearing across consumers who benefit from system strength and/or generators (notably renewables) that might benefit from avoided curtailment.

E. Power System Security Ancillary Services Market

7.95 Inertia, in common with system strength and some voltage support services, is currently provided by synchronous resources (generators injecting power or generators operating in synchronous condenser mode). A key short-term challenge facing AEMO is to ensure sufficient commitment by resources to provide all three of these services, inertia, voltage support and system strength, jointly referred to as "synchronous services" or "Power System Security Ancillary Services (PSSAS)". This section sets out the broad features of a design for a competitive process to jointly procure inertia, system strength and some voltage support services.[189] It also identifies some of the key limitations of the basic design and outlines areas in which the design could be refined further.

[189] We note upfront that the nature of PSSAS is a centralised ahead commitment, i.e. it departs from the current self-commitment RT provision in the NEM design.

E.1 Overview of PSSAS proposal

7.96 A proposal from ERM and CS Energy[190] suggested that when the projected supply of synchronous services (inertia, system strength, and/or voltage support) was inadequate, AEMO would run a competitive process (e.g. auction) to elicit bids from resources to provide synchronous services. AEMO would use this process to evaluate the cost of acquiring the services to meet the projected needs (by committing additional resources) and select a combination of resources based on their bid characteristics (minimum load offer price above the projected energy market price[191], start-up cost, etc), which AEMO could then commit in the dispatch. The intention of this approach is that the resources needed to meet PSSAS requirements at least cost would be committed by AEMO and their output would be co-optimised with Energy, FCAS and Ramp Rate Ancillary Services ("**RRAS**"), via the NEMDE and the NEMDE pre-dispatch run process.

7.97 Successful bidders would have an obligation to respond to AEMO's commitment instructions (i.e. to start up and maintain a level of service for a pre-defined period), in return for compensation based on the resources' bids.

7.98 The objective of this approach would be to give AEMO the confidence that sufficient resources will be available to respond to a commitment instruction and to deliver sufficient system security, while introducing an element of competition into the procurement process to reduce the costs at which AEMO procures synchronous services.

7.99 In Figure 7-7 below, and in more detail in subsections that follow, we describe the basic approach to the compensation, resource selection, commitment decisions, price formation and market power in turn, and describe some minor variations that would potentially improve outcomes. In the final section, we summarise the approach and propose relatively major changes for the evolution of the design.

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190 Draft proposal received from ESB on 26 June 2020. Where appropriate, we have defined some elements of the proposed design in order to fill in the gaps in the draft description provided to us.

191 This would be considered over either the duration of the minimum run time, or the period over which the synchronous services was needed – whichever was longer.

Figure 7-7: Summary of the PSSAS proposal

	PSSAS Base Case	Key limitations	Potential refinements	Implementation of refinements
1 **Issue 1: Compensation approach**	• Compensation varies by resource: ❑ No compensation for self-committed, already online resources ❑ Offline generating resources compensated via "top up" to the RRP energy price up to min load ❑ Offline non-generating resources compensated through a $/energy market dispatch interval, based on offer bids	A. Inframarginal resources have an incentive to inflate MW value of min load B. No compensation to self-committed resources leads to (i) no forward price signal for self-commitment; (ii) undermining self commitment; and (iii) incentivizes online resources to decommit	**Pay online self-scheduled resources for providing PSSAS** • **Option 1:** Online resource to submit offer prices for min load and pay difference between bid and RRP for min load • **Option 2:** Back out a price for inertia by calculating the payments to each resource providing inertia and the amount of inertia provided • **Option 3:** AEMO specifies rough value for PSSAS and solves a set of questions to produce a set of best fit payments • **Option 4:** Option 3, but with added set of constraints to be consistent with the costs of the resources that were not committed	✓ Provide more efficient incentives for the continued operation of resources ✓ Avoids discouraging participation in the NEM energy market × AEMO required to estimate amount of service provided by each resource and ex post pricing × No forward price signal × Inconsistency between PSSAS market and overall self-commitment based NEM design × Refinement of details may be complex – system of equations and ex post pricing design
2 **Issue 2: Resource selection**	• Competition between bidders • AEMO should be able to identify least-cost option for PSSAS • Evaluation of different resource combinations should enable AEMO to consider ability of resources to provide multiple PSSAS	C. AEMO needs to evaluate the cost of using a large number of alternative combinations of units D. A siloed approach to procuring each PSSAS could fail to deliver least cost solutions	**Joint evaluation of the cost of meeting all PSSAS requirements** • AEMO would jointly evaluate the cost of using each resource or combination of resources to meet the combined inertia, system strength and voltage control needs over the projected period of need in deciding which resources to commit	✓ Reduce (or even eliminate) the inefficiencies due to separate procurement resources to meet each PSSAS requirement
3 **Issue 3: Commitment decisions**	• Dispatch based on AEMO's assessment of lowest cost provision for PSSAS co-optimised with Energy, FCAS and RRAS	E. "Just enough" commitment may not be efficient F. Varying start up times may make "last moment" decisions inefficient G. Advanced commitment makes economic evaluation challenging	**Increase procurement targets** • **Option 1:** AEMO could increase the procurement targets based on its judgment of future system conditions • **Option 2 (major design change):** definition of an explicit demand curve for additional PSSAS, with more procurement when costs are low	**Option 1:** ✓ System should be more robust × Ad-hoc judgements increase burden on AEMO × Absolute procurement requirement could result in inflated consumer costs **Option 2:** ✓ System should be more robust without risk of excessive costs ✓ Would enable the demand curve based compensation of online resources
4 **Issue 4: Price formation**	• RT prices calculated based on energy supply excluding the min load output of resources committed by AEMO	H. Inconsistencies between energy settlement prices, offer prices and dispatch instructions for some resources – incentivising inefficient behaviour by resources	**No adjustment of RT energy prices for commitment of PSSAS** • **Option 1**: RT energy price for settlements would be adjusted to exclude the minimum load block of resources committed to provide PSSAS • **Option 2 (major design change)**: RT energy price for settlements would be calculated without adjustment for resources committed to provide PSSAS • Implemented in parallel with compensation option 4 - online resources providing PSSAS services would receive compensation	✓ Online resources receive compensation ✓ More efficient pricing - resources providing little PSSAS receive lower energy price × Refinement of details may be complex – system of equations and ex post pricing design

Source: FTI analysis

E.2 Compensation approach

7.100 In the proposed approach, the compensation approach differs depending on the category of the resources:

- **Online resources**, which are resources that are already online in the energy market (i.e. self-committed) would not receive any compensation for providing the PSSAS.
- **Offline generating resources,** which would need to be brought online to deliver PSSAS, would be compensated through a "top-up" to the RRP energy price, i.e. the difference between their offer bid to provide synchronous services and RRP, for capacity up to the minimum load block, and would also be compensated for their start-up costs (as bid).[192] There would be no additional compensation for capacity dispatched above the minimum load (i.e. the resource would only be compensated through the RRP for energy output above the minimum load).[193]
- **Offline non-generating resources**, which would also need to be brought online (e.g. synchronous condensers) would be compensated through a $/energy market dispatch interval, based on their offer prices (which would enable resources to submit bids that reflect their start-up and running costs).

7.101 This approach implies that AEMO would typically commit resources to provide ESS and bring them online at their minimum load output, as operation at minimum load would be sufficient for the resource to provide all three types of synchronous services (inertia, system strength and voltage control). However, it may be appropriate to examine whether in some cases, higher load can provide additional PSSAS: for example, above-minimum load would provide higher inertia than just the minimum load.

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192 For example, if the offered minimum load cost was $55/MW and the RRP was $40/MW, the resource would be paid $15/MW for its minimum load output.

193 Once dispatched for PSSAS the resource would not be allowed to alter its offer price or minimum load value for the duration of the provision of PSSAS for which the dispatch instruction applied (and could only withdraw based on verifiable plant condition), in line with general good practice. This applies both to generating and non-generating resources.

7.102 There are several clarifications that would need to be provided to progress the development of this approach:

- An appropriate reference RRP needs to be defined so that market participants understand how the “top-up” payment will be calculated. It is envisioned that the competitive evaluation by AEMO would be based on AEMO’s RRP price forecast from pre-dispatch, while the actual payment would be based on the RT RRP.
- It is envisioned that resources committed by AEMO to provide PSSAS could be dispatched above the minimum load block for energy, for FCAS or both. It is envisioned also that resources – when dispatched above the minimum load – would retain the PSSAS payment for up to the minimum load block.
- For non-generating resources, compensation for dispatch of energy (>0) as a result of AEMO dispatch instruction needs to be clarified, i.e. whether the resource would continue receiving PSSAS payment (received in anticipation of providing PSSAS without injecting energy), or only the RRP. The risk of the latter approach is that if the resource was dispatched by NEMDE for energy (even though the resource was previously committed to provide PSSAS without injecting energy), this resource would lose the PSSAS payment and only receive the RRP, which may not be sufficient to cover its costs. Hence, the preferred design would likely be to allow these resources to retain the PSSAS payment when dispatched for energy, as long as the resource continued to provide the PSSAS.

7.103 There are also several limitations with this approach to compensation for resources providing PSSAS.

7.104 First, for offline generating resources, since the top-up to the RRP is only available up to the minimum load, inframarginal resources will have an incentive to inflate the MW value of their minimum loads to receive higher pay-as-bid compensation for providing PSSAS. Like all pay-as-bid market designs, this could result in some economic inefficiency.

7.105 Second, and more importantly, online resources (i.e. self-committed resources) would not receive any compensation for providing PSSAS. This means this approach could:

- Fail to provide a price signal for the self-commitment of resources able to meet PSSAS needs at least cost;[194]
- Fail to provide a contribution to covering the going forward costs of self-committed resources able to provide PSSAS;
- Tend to undermine the current self-commitment based NEM energy market by providing higher returns to resources committed by AEMO to provide PSSAS then also dispatched for energy, than if the resource were self-committed and dispatched for energy; and
- Create incentives for online resources to decommit in order to receive compensation, unless this was addressed with other rules.

> Potential refinement: Provide a payment for online resources that provide PSSAS.
>
> This would provide more efficient incentives for the continued operation of resources that are able to efficiently provide PSSAS and also avoid discouraging participation in the NEM energy market.
>
> However, this refinement would involve major design changes that would have some of the key implementation challenges discussed earlier in relation to the forward contracting and spot-market demand curve designs:
>
> First, the method for calculating prices, and the method for determining payments to self-committed resources, requires AEMO to estimate the amount of inertia, voltage control and system strength provided by resources that were online, by those committed by AEMO to provide PSSAS, and by those able to provide PSSAS but not committed by AEMO. This is important to develop an appropriate pricing mechanism. The basic design only requires that AEMO be able to determine the set of resources that meets its inertia, system strength, and voltage support needs, so this refinement requires AEMO to go a step further and provide at least a rough measure of how much inertia, system strength and voltage support resources provide. This would be reasonably workable for inertia but might be a challenge for other services.
>
> Second, AEMO would need to develop an ex-post pricing design that would be able to calculate ex-post prices from the unit commitment solution based on projected PSSAS needs and projected energy prices.

194 Although the self-committed resources did not require any PSSAS payment, this approach would not provide a price signal for additional resources to come online. Instead, all commitments would need to be made by AEMO.

The key benefit of this refinement is being able to set **compensation for PSSAS provided by online resources.** We outline several options for calculating prices and their limitations.

Option 1: AEMO could allow online resources to submit offer prices for their minimum load and pay them the difference between the RRP and the offer price for their minimum load block in the same manner as offline resources committed by AEMO. However, this would not provide the online resources with efficient bidding incentives since the resources are already online. There is no minimum load cost to acquiring PSSAS from these resources. The resources could bid very high minimum load costs, and thus obtain high payments, even if they were economic in the energy market. AEMO could also pay these resources the difference between a cost-based minimum load cost and the energy price, but this payment would not be related to the market value of the PSSAS the resources provide.

Option 2: It might be possible to back out an average cost-based price for inertia by calculating the minimum load based payment to each resource providing inertia and dividing this cost by the amount of inertia provided. However, this would not necessarily provide an accurate measure of the cost of inertia, as some of these resources might have been committed because they also meet system strength or voltage control needs.

Option 3: If AEMO could specify a rough value for the system strength and voltage control provided by each resource, it could solve a set of equations over all of the units committed by AEMO based on its economic evaluation for the inertia, system strength and voltage control prices that best fit the payments to the resources committed by AEMO. This would need to be an ex-post pricing type design that would choose the prices most consistent with the payments, as there generally would not be an exact solution. These estimated prices could then be used to compensate the online resources based on the estimated amounts of system strength, inertia and voltage control they provide. In addition to the need to define estimates of the relative amount of system strength, inertia and voltage control provided, this approach could yield anomalous estimates of the implicit cost of PSSAS, particularly if only one or two units need to be committed.

Option 4: This approach would be the same as Option 3 except that in addition to choosing the prices most consistent with the cost of committing the resources that were committed, it would add a set of constraints that the prices be consistent with the costs of the resources that were not committed. Thus, the costs of the resources committed would set lower bounds on prices and the costs of resources that were not committed would set upper bounds, choosing prices that minimised violations. This approach should be workable under many conditions. It might not yield a reasonable solution for needs that could only be met with a small number of resources, but these situations would raise market power issues as well. We also anticipate, based on our experience with similar ex-post pricing rules, that the solution mechanism would need some weighting rules for bounds violations that would need some testing. A key challenge would be the need to assign rough values to the system strength and voltage control provided by individual units in order to calculate settlement prices.

Another complexity with a design based on either Option 3 or 4 above is that while it should be possible to calculate prices for the individual PSSAS that would be consistent with the ex-ante commitment decisions based on projected energy prices, it might not be feasible to calculate PSSAS prices that would be consistent with the commitment decisions and actual RT energy prices. We envision that AEMO could settle PSSAS provided by self-committed resources using the projected prices, while paying resources committed by AEMO based on their minimum load offer prices.

There are also several limitations to this refinement.

First, it could not be used to support a design based largely on self-commitment of resources providing PSSAS because if AEMO were not committing any resources, the projected prices would be zero. Hence, there would only be positive prices when AEMO needed to commit additional resources. This means that market alone could not, by construction, solve any shortfalls of PSSAS as the price signal would only exist if AEMO committed some resources.

Second, while this design would provide compensation to self-committed resources able to provide PSSAS, it would not provide a forward price signal for self-commitment. There would remain a degree of inconsistency between the PSSAS market and the overall self-commitment based NEM design (e.g. in terms of prices, as discussed in a later subsection on price formation) but the issues would be reduced by the payments for system services to self-commitment units whenever AEMO paid to commit additional units.

E.3 Resource selection

7.106 The proposed approach aims to deliver a degree of competitive tension between providers of PSSAS (in terms of minimum load blocks, costs at the minimum load and start-up costs) such that AEMO is able to identify the least-cost option for PSSAS.

7.107 In addition, the economic evaluation of different combinations of resources is intended to enable AEMO to take account the ability of a single resource to provide multiple PSSAS, and to take these trade-offs into account in the commitment decisions.

7.108 There are several design elements that would need to be developed further to progress the implementation of this approach:

- AEMO needs to define combinations of generating and non-generating resources that could meet the target requirement for each synchronous service (e.g. inertia, voltage control and system strength), and evaluate the cost of using each such combination to meet the targets over the projected period. These combinations of resources could be expressed, for example, in a tabular format similar to the TLA Tables published by AEMO. This information is necessary for AEMO to be able to decide which resource(s) to commit, and at what point in time, to meet the system needs in each time period.
- For transparency, bidders need to understand how they are evaluated and selected, so that they can adjust their bids over time accordingly. This means that bidders need to understand how AEMO forms a view on the need for PSSAS, as described in the bullet above.
- Resources need to understand what service they are dispatched for (inertia, system strength, etc) so that efficient investment decisions can be made, particularly in areas where only one (but not all) of the PSSAS is deficient.

7.109 The key challenges with this approach are that:

- AEMO may need to be able to evaluate the cost of using a large number of alternative combinations of units to meet the individual PSSAS procurement targets over the horizon of the projected need for each PSSAS. This is a common challenge in unit commitment designs and methods have been developed to solve the typical unit commitment problem in the context of energy and ancillary service requirements. While we do not have specific concerns that cause us to anticipate that the solution time or methodology would provide unresolvable barriers to the implementation of such a design, we recognise that this design would have some unique elements of the optimisation problem that might create challenges. Hence, it would be important for AEMO to have some preliminary conceptual discussions with vendors if it were to consider developing such a market design.
- AEMO would have a choice to either procure each PSSAS separately, or to undertake a joint assessment. A siloed approach could result in outcomes in which the sum of the individual procurements was not least cost, so a combined approach is likely to be more efficient.

Potential refinement: When AEMO projects a need to acquire multiple PSSAS, it should jointly evaluate the cost of meeting all of those PSSAS requirements by committing additional resources.

AEMO would jointly evaluate the cost of using each resource or combination of resources to meet the combined inertia, system strength and voltage control needs over the projected period of need in deciding which resources to commit at what point in time to meet the PSSAS requirements in each time period.

This refinement should reduce (or even eliminate) the inefficiencies due to separate procurement resources to meet each PSSAS requirement.

E.4 Commitment decisions

7.110 In the proposed approach, dispatch (i.e. the commitment of the minimum load block) would be based on AEMO's assessment of lowest cost provision for PSSAS co-optimised with Energy, FCAS and RRAS, via the NEMDE using the energy prices projected by the NEMDE pre-dispatch run process.

7.111 One approach, as proposed in the basic design, would be for AEMO to wait until the last moment before committing resources to meet PSSAS needs (so as to have the best information available and to minimise unnecessary interventions).

7.112 Key challenges with this approach are that:

- Different combinations of resources are likely to have different start-up times and would need to be committed at different times. It may therefore not be optimal for AEMO to wait until the "last moment", as earlier commitment could reduce total costs of system security. Indeed, if AEMO waited until the "last moment" to evaluate resources to meet PSSAS needs, there might be no choices to evaluate, as there could be only one option left. To address this possibility, AEMO would likely need to develop clear criteria to assess the trade-offs between earlier commitment of cheaper resources whose operation might turn out later to not be needed and last-minute commitment of more expensive resources.
- AEMO may need to commit resources well in advance of the operating hour in order to provide PSSAS. Such advance commitment could make it challenging for AEMO to carry out the economic evaluation based on projected energy market prices, as these may be highly uncertain (particularly if the penetration of VRE is high).

- The basic approach envisions that AEMO would commit “just enough” resources to meet the minimum PSSAS requirement at the time the commitment decision is made. This might not be fully optimal, particularly in evaluating units with long start times. This is because of the potential for changes in system conditions and/or resource availability over time that would require subsequent commitment of additional resources, as well as the potential for resources selected to meet PSSAS requirements to be unable to come online as directed, again requiring subsequent commitment of additional resources.

Potential minor refinement: Instead of just procuring the minimum amount of PSSAS required to maintain security, AEMO could increase the procurement targets based on its judgment regarding future system conditions and potential additional PSSAS needs. This refinement should make the design more robust to changes in system conditions, because it would allow AEMO to better respond to potential changes in system conditions over time (as well as mitigate the risk that committed resource is unable to come online as directed). However, it would also give AEMO more discretion in terms of operating the system, which may or may not be appropriate (see Section 8).[195]

However, this refinement would have two potential downsides:

- First, the need to make these ad-hoc judgments would require additional operator time and attention.

- Second, basing these additional commitments on an absolute procurement requirement could result in inflated consumer costs, both as a result of operator decisions and as a result of inducing changes in generator bidding behaviour. The potential for very high cost procurements could be reduced by providing operators with tools to assess these costs or iteratively running the evaluations with different targets to achieve an appropriate cost-benefit trade-off. However, this would greatly magnify the demands for operator time and attention during potentially uncertain system conditions.

[195] Further analysis may be required to explore the interaction of this approach and ahead mechanisms with potential intraday trading and defined run times.

E.5 Price formation

7.117 In the proposed approach, RT energy prices for settlements would not be based on total energy supply (i.e. self-committed resources plus resources committed by AEMO to provide PSSAS); rather, they would be calculated based on energy supply excluding the minimum load output of the resources committed at minimum load by AEMO to provide PSSAS from the dispatch. These prices would aim to be the "would-be" prices that would have emerged from the energy market dispatch of self-committed resources if AEMO had not intervened to commit additional resources to deliver PSSAS that also supplied energy.

7.118 This method of calculating energy prices would lead to inconsistencies between energy settlement prices, energy offer prices and energy dispatch instructions for some resources. This would tend to incentivise inefficient behaviour by resources, for example by unduly incentivising the self-commitment of resources unable to provide the required PSSAS.

Potential minor refinement: The RT prices for settlements for resources providing PSSAS would be calculated based on energy supply excluding the minimum load output of the resources committed at minimum load by AEMO to provide PSSAS from the dispatch. However, the RT prices for settlements for other resources would not be so adjusted.

E.6 Market power issues

7.119 Where only a small number of resources could provide PSSAS, there would be a risk of local market power which could be partially mitigated through the proposed market price cap. The market price cap could become the focal point for some bidders, and would effectively replace any competitive outcomes, so the Reliability Panel would need to implement additional measures to ensure it is not excessively generous (e.g. as part of the Reliability Standard and Settings review process). However, market power issues are not explored in detail in this section.

E.7 Summary and further evolution of the design

7.120 The basic design outlined above, with some refinements, would enable AEMO to operate a competitive process for committing additional resources to meet PSSAS needs. In addition to the refinements proposed above, there may be a case for considering two additional major changes to the design, relating to (i) the commitment decisions process and to (ii) price formation. These represent more significant changes to the PSSAS approach, and require that some of the minor refinements outline above are also implemented.

Major design change for commitment decisions:

Instead of procuring additional PSSAS based on SO judgment that is independent of cost, this design change would be based on an explicit demand curve for additional PSSAS with more services procured if the cost of incremental supply was low and perhaps procuring only the minimum requirement if the cost of incremental services was very high.

Like the other refinement outlined above for price formation, this design change requires that AEMO be able to define the amount of inertia, system strength and voltage support provided by each resource.

The direct benefit of this refinement is that it would enable AEMO to procure PSSAS beyond the minimum, thus improving AEMO's ability to respond to changes in system conditions and resource availability, but without the potential for inadvertently resulting in very high cost procurements.

A second indirect benefit of this refinement is that solving the commitment problem based on the demand curve would enable AEMO to calculate projected prices for PSSAS in each future period and the demand curve could also be used to calculate RT prices for each PSSAS that would be consistent with the RT dispatch and able to support self-commitment decisions. These prices would be paid to all resources providing PSSAS (i.e. offline and online resources). This design change could therefore support a design with the previously described refinement that introduces compensation for online resources (see ¶7.105). It would also be consistent with the NEMs current self-commitment design with centralised commitment of resources by AEMO serving a backstop role.

Major design change for price formation:

Under this design change, RT energy price for settlements would be calculated without adjustment for resources committed to provide PSSAS.

This design change would be implemented jointly with the refinement discussed earlier to provide a compensation to online resources providing PSSAS – see ¶7.105. Specifically, this design change would be implemented with Option 4 set out in the discussion of compensation options.

The advantages of this design change are that:

- Online resources providing PSSAS would receive compensation for providing those services that would offset the reduction in energy prices from the commitment of additional resources needed to provide these services.
- Resources that provided little or no PSSAS would be appropriately exposed to the lower energy prices resulting from the need to commit resources able to meet PSSAS needs. The benefit of this design change, relative to the other designs, is that it would provide more efficient incentives for the continued operation of resources able to efficiently provide PSSAS and also avoid discouraging participation in the NEM energy market.
- Compared to just compensating self-committed resources, this design change would provide more efficient energy market pricing and avoid incentivising higher output or commitment of resources unable to provide PSSAS.

A key challenge with this design change is the exact details of the compensation approach for online resources. Building on Option 4 discussed in ¶7.105, we envisage an approach where AEMO would specify a rough value for the system strength and voltage control provided by each resource. AEMO would solve a set of equations (which would be defined over (i) all of the resources committed to provide PSSAS; and (ii) resources able to provide PSSAS that were not committed) for the inertia, system strength and voltage control prices that best fit the payments to the resources that were committed and the decision not to commit the resources that were not committed. This would need to be an ex-post pricing type design that would choose the prices most consistent with the payments and commitment decisions as there generally would not be an exact solution. These estimated prices could then be used to compensate the online resources based on the estimated amounts of system strength, inertia and voltage control they provide.[196]

Thus, the costs of the resources committed would set lower bounds on prices and the costs of resources that were not committed would set upper bounds, choosing prices that minimised violations. This approach is likely to be workable under many conditions. This design might not yield a reasonable solution for needs that could only be met with a small number of resources, but these situations would raise market power issues as well. We also anticipate based on our experience with this kind of ex-post pricing rules that the solution mechanism would need some weighting rules for bounds violations that would need some testing. The key challenge would be the need to assign rough values to the system strength and voltage control provided by individual units.

7.121 This basic design would have a number of implementation challenges and would not provide a spot-market-based framework for self-commitment of resources able to meet PSSAS needs. It could, however, serve as a starting point for the evolution towards such as design, and could be retained as a backstop mechanism following the evolution to a more spot-market-based design.

7.122 There would be three significant evolutionary steps that could follow from the implementation of the basic design towards a market-based design:

- First, the calculation of ex-post prices for PSSAS provided by online resources;
- Second, the use of a demand curve for committing resources to provide PSSAS using this design with prices for PSSAS determined by the demand curve; and
- Third, elimination of any intervention-based pricing.

196 A potential challenge with this approach is that the price formation is likely to be perceived to be non-transparent, which could weaken investment signals to resources.

7.123 Overall, the PSSAS proposal, augmented by the refinements proposed in this section, would be akin to the innovative design for inertia and system strength described in Sections 7C.2 and 7D.2 of this report, with the difference that the PSSAS proposal would also be supported by a back-stop unit commitment process coordinated by AEMO. Importantly, the basic PSSAS design, without the price formation refinements or the demand curve refinements, could be implemented without the need for AEMO to specify a measure of the amount of system strength provided by individual resources, or the amount of system strength needed based on this measure. The basic PSSAS design could therefore serve as both a transition and as a back-up design for meeting system strength requirements, while a spot-market-based design is being developed and also as it is implemented.

8. Future flexible regulatory framework

8.1 In the NEM, the regulatory framework for system services is currently defined in the NER. The responsibilities arising from this framework are spread across multiple parties, including the Reliability Panel, AEMO, AER, NSPs and generators, through a variety of direct NER obligations, system standards developed by the Reliability Panel, and market operating procedures developed by AEMO.

8.2 The existing regulatory framework for system services has been developed and tested over time, in line with the evolution of the NEM market arrangements and is considered to have been broadly effective. However, as we discussed in earlier sections of this report, the needs of the system are changing rapidly. In light of this, we consider in this section whether the current regulatory arrangements for the procurement of system services (i.e. ensuring that adequate resources exist to provide the services, some of which may need to be constructed) and the terms of scheduling them (i.e. dispatching existing resources in RT) will continue to be effective, or whether changes may need to be made.

8.3 In this section, we therefore first examine the current NEM regulatory environment, and identify areas where changes could be considered. We find that there may be some potential for evolution towards a more flexible approach than may have been used historically (**Section A**).

8.4 The implementation of a more flexible regulatory framework could potentially deliver benefits to consumers, but there may also challenges associated with increasing the flexibility of the framework. In **Section B,** we consider what a more flexible framework might mean for ESS procured by AEMO, for regulated investments by NSPs and for ESS that are driven by the wider technical and performance standards.

8.5 In an effective regulatory regime, particularly in the context of a transition to a VRE/IBR dominated world, a degree of discretion by some decision makers, at certain times, is likely to be desirable or even necessary. However, to complement that discretion, there needs to be a range of checks and balances in place to ensure that responsible entities are appropriately accountable to policy makers and, in turn, ultimately the customers that they serve. Therefore, in **Section C**, we consider the range of possible regulatory checks and balances that could be put in place to ensure the procurement and scheduling of ESS is undertaken in the interests of customers. The regulatory framework, including the checks and balances, can thus provide an operating envelope, within which decision makers can benefit from a degree of flexibility, and this flexibility can adjust over time as the confidence in the framework is built.

8.6 Finally, we discuss how investability in resources can be maintained in the context of a more flexible regulatory regime supported by a range of checks and balances (**Section D**). **Section E** concludes.

A. Current NEM regulatory arrangements

8.7 The current approach to the procurement and scheduling of ESS is overseen by a large number of regulatory bodies. The NER set out the responsibilities that regulatory bodies and other parties have under the existing regulatory arrangements. At a high level:

- The Reliability Panel establishes the relevant system standards for the provision of services, which may apply to resources and/or networks.
- AEMO is responsible for the market operating procedures, plays a role in the implementation and procurement of system services, and is also responsible for managing scheduling and dispatch.
- AER provides regulatory oversight of the electricity networks, and enforce the laws of the National Electricity Market and the Retail Law.[197] For example, for non-spot-market investments that are undertaken by TNSPs, AER assesses the compliance of the TNSPs in their undertaking of the RIT-T and, in some circumstances, issues determinations on the proposals. AER also approves the level of costs to be recovered through TNSPs' regulated revenues.

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197 "*[AER] regulate electricity networks […] in all jurisdictions except Western Australia. [AER] set the amount of revenue that network businesses can recover from customers for using these networks. [AER] enforce the laws for the National Electricity Market […] in southern and eastern Australia.*" Source; AER, About Us website (link). Accessed 10/07/2020.

- AEMC plays a key role in setting detailed rules and evaluating proposed changes (the change process is explained in more detail below).
- NSPs, generators and other resources (e.g. storage and DR) face obligations arising from the ESS rules, which are specific to each of the relevant services.
- ESB is currently advising the COAG, as part of the Post-2025 Market Design, on the development of a long-term, fit for purpose framework for ESS to support reliability and security in the NEM.

8.8 Detailed rules are in place for NSCAS, SRAS, FCAS and RERT, as these services are currently defined as separate classes of ancillary services (or ESS) within the NEM. For other services, some the rules are limited in their application and are seen to be potentially inefficient (although perhaps more efficient than if those rules were absent).

8.9 Changes to the procurement and scheduling of ESS are considered and evaluated through a multi-layered **Rule Change process.** This process typically involves AEMC, AEMO, ESB and AER, as well as the relevant market participants involved in the changes. In summary, this process has the following features:

- Any interested party in the NEM (except AEMC), including consumers, governments and energy regulatory market bodies, can propose a change to the market rules.
- AEMC evaluates these proposals through a formal rule change process, leading to a formal rule determination.
- For standard rule changes this process can take around 6 months (although this can be extended) with two rounds of stakeholder engagement, but expedited or fast-tracked rule changes can deliver a final determination within 8 weeks from submission.[198]

[198] AEMC, Changing the energy rules (link). Accessed 29/05/2020.

- In relation to ESS, AEMC regularly reviews proposals from a range of parties. Examples of this include (i) Infigen's March 2020 rule change request relating to operating reserves and fast frequency response;[199] (ii) a May 2019 rule change request submitted by Dr Sokolowski of RMIT University as a private individual, which aimed to improve the control of frequency in the NEM;[200] and (iii) AEMO's July 2019 SRAS rule change request.[201] While the Infigen rule change request was only recently initiated,[202] Dr Sokolowski's frequency response and AEMO's SRAS rule change request processes were completed in March 2020[203] and April 2020[204] respectively, resulting in amendments to the NER. Both were consolidated with other similar rule change requests from different parties (for example, AEMO's request was consolidated with an AER request which also related to SRAS[205]), and then followed the standard rule change process.

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199 Infigen, Letter to AEMC Re: Operating Reserves and Fast Frequency Response Rule Change, 18 March 2020 (link).

200 Dr Sokolowski, Letter to AEMC: Frequency Control Rule Change Request, 30 May 2019 (link).

201 AEMO, Letter to AMEC: National Electricity Rule change proposal – Future system restart capability, 29 July 2019 (link).

202 AEMC, Fast frequency response market ancillary service rule change request website (link), Accessed 10/07/2020; and AEMC, Operating reserve market rule change request website (link), Accessed 10/07/2020.

203 AEMC, National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5, March 2020 (link).

204 AEMC, National Electricity Amendment (System restart services, standards and testing) Rule 2020 No.6, April 2020 (link).

205 AEMC, System restart services, standards and testing website (link). Accessed 10/07/2020.

8.10 Other changes to the ESS regulatory arrangements fall under the remit of the Reliability Panel. The Panel is comprised of representatives from a range of industry and consumer organisations including AEMO, generators and consumer groups, and focuses on determining the standards and settings that are required to deliver a secure, reliable and safe power system, while minimising costs to consumers.[206] Importantly, the Panel sets the NEM's Reliability Standard, which expresses the desired level of reliability within the NEM, and is set as a maximum percentage of unserved energy for each year.[207] Every four years, the Panel reviews the Reliability Standard (as well as the market price cap, which imposes a cap on temporary high prices in the wholesale electricity market) to ensure that it remains suitable for the current market. The Panel also produces guidelines to assist AEMO in performing its role as the SO (e.g. guidelines on the operation of RERT).[208]

8.11 Beyond the setting of standards and guidance, the Panel monitors the market, analyses its performance, and undertakes consultations. This includes the publication of an annual market performance review paper, which comments on the security, reliability and safety of the NEM.

8.12 As set out above, the NEM has processes in place to adapt and improve the design of the NEM, including for ESS. This approach – to the extent that it relies on multilateral discussions, public consultations and an ad-hoc approach to assessing Rule Change requests (initiated by market participants) – has, we understand from ESB, worked well in situations where the need for change was identified well in advance and the change is relatively discrete (i.e. it has limited repercussions on the wider market).

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206 AEMC, Reliability Panel website (link). Accessed 30/06/2020.

207 AEMC, Reliability Standard Factsheet, February 2020 (link), pages 2 & 3.

208 AEMC, Developing electricity guidelines and standards website (link). Accessed 30/06/2020.

B. Augmenting the flexibility of the regulatory regime

8.13 As technology develops and wider market conditions evolve, the procurement and scheduling of ESS should be able to adjust to meet the evolving needs of the system. For example*:*

- If a **need for existing services** changes due to the rapid transition to a system with high VRE/IBR penetration (for example the regional or total need for a particular service changes), the regulatory framework should enable the procurement to adapt proportionately and in a timely manner.
- If a **need for new services** becomes apparent (e.g. where the need was previously not apparent because the service was provided as part of the provision of other services from large synchronous generators), the regulatory framework may need to be able to incorporate explicit procurement of and compensation for such services (e.g. inertia and system strength).
- If **new technologies** emerge that can provide a new combination of services, or otherwise deliver value to consumers, these may need to be reflected in the procurement framework.

8.14 More generally, it seems appropriate that the regulatory regime should support (and potentially encourage) innovation by actively looking for opportunities to broaden the **eligibility** of potential providers of services to a wider pool of participants (subject to objective technical performance criteria and costs).

8.15 As explored in Section 7, there is a range of mechanisms (such as structured procurement by AEMO and TNSPs, spot markets, and technical standards) that may contribute to increasing system security. In the following subsections, we examine how the regulatory regime can offer additional flexibility to the different mechanisms, considering AEMO, TNSPs and technical standards in turn.

Role of AEMO

8.16 AEMO seeks to "*promote the efficient investment in, and efficient operation and use of, gas and electricity for the long-term interests of Australian consumers in relation to price, quality, safety, reliability and security*".[209] This includes the responsibility for: (i) maintaining secure electricity systems; (ii) managing electricity markets; and (iii) leading the design of Australia's future energy system. The role played by AEMO has an impact on the costs paid by consumers both directly (e.g. the operating costs incurred by AEMO are recovered through fees paid by industry participants) as well as indirectly (e.g. actions taken by AEMO can impact the costs incurred by generators and/or NSPs, which may be passed through to consumers via bills).

8.17 However, it is not always immediately clear to regulatory authorities whether AEMO has delivered system security in a cost-efficient manner. This is because security is more observable than the costs:

- Whether or not an adequate level of system security has been delivered can generally be observed by regulatory authorities (e.g. it is obvious if a blackout has occurred or if a state became islanded).[210]
- By contrast, there is an asymmetry of information between the SO and the regulatory authorities regarding the costs in maintaining system security: it is not straightforward to observe for any external party whether a given level of system security has indeed been achieved by the SO at least cost.

8.18 This difference of observability of the outcomes in terms of system security and the costs required to achieve it have a bearing on AEMO's incentives. In particular, the highly transparent consequences of system security failure, together with highly opaque nature of cost efficiency, mean that SOs are, understandably, likely to have an in-built bias towards operating the system in a relatively conservative manner. For example, they might choose to purchase additional system services to maintain security of supply above levels actually needed to mitigate the potential adverse consequences of system failure. This tendency towards excessive conservativeness by SOs might need to be managed appropriately.

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209 AEMO, What we do website (link). Accessed 10/07/2020.

210 Moreover, a failure to maintain a secure system has significant adverse consequences to customers but also to the SO organisation charged with maintaining system security. These consequences may be observed either in monetary and/or, more likely, reputational terms.

8.19 One approach to mitigating this tendency towards excessive conservativeness is to put in place rules and standards that need to be observed by the procuring SO – for example specifying certain quantums of services that need to be procured in given timescales. However, this runs the risk of being overly restrictive, as the standards, by design, are likely to be relatively static in nature and may not be able to respond in a timely manner to fast moving changes in system conditions (that might lead to less or more of service being required). In turn, this runs risk of imposing additional costs on customers.

8.20 To mitigate the risk of restrictive standards, there may be a case of allowing SOs a degree of latitude or discretion in how it chooses to maintain system security. For example, the SO may be subject to statutory incentives and operate with a set of well-defined tools, decision criteria and accountability, which would aim to mitigate the tendency towards an overly conservative behaviour, while also enabling the SO to act with confidence that they will not be inappropriately penalised for taking (or failing to take) a particular action.

8.21 This would have the benefit of allowing the responsible entity the discretion to meet system conditions dynamically. However, with it comes the risk described above that the responsible entity (e.g. SO) is unduly cautious and its decisions impose additional costs on the system that ultimately fall upon customers.

8.22 In our view, the appropriate regulatory framework therefore needs to find a balance between "too much" and "too little" flexibility of the regulatory regime. There are risks associated with both ends of the spectrum:

- **"Too much" flexibility.** As set out above, private incentives may lead AEMO to operate the system more conservatively than would be in consumer interest.[211] For example:
  - The SO may take unduly conservative (risk-averse) investment and/or operational decisions, including decisions that are not cost efficient or in the long-term interests of consumers. Such overspend may be difficult for regulators and market participants to monitor due to the asymmetry of information between AEMO and external parties.

211 Additionally, potential investors may be deterred by significant SO flexibility, due to perceptions of market instability and increased revenue uncertainty. See Section 8D.

- This could also arise, for example, if decisions were made without sufficiently consulting and refining the proposals. This risk is more acute in situations where the change is likely to have significant impacts[212] and when the technical (system-specific) complexity is low, such that there is higher value of external scrutiny and stakeholder engagement.

- **"Too little" flexibility.** Conversely, lack of flexibility may mean that AEMO might operate within a "straitjacket" of inflexible rules, which may at times[213] force AEMO to make sub-optimal decisions or fail to take appropriate action to prevent adverse outcomes. For example:
  - AEMO may, in line with the rules, spend too much or too little on delivering system security relative to what might have been in consumer interest.
  - This risk is more acute in situations of high urgency and time-critical changes, where delays would cause consumer detriment simply because AEMO would not be able to make changes prior to the rules themselves being formally changed.
  - This risk is also relevant in cases where there is a higher ongoing need to fine-tune the settings (e.g. in the early years following significant market change, or for a learning-by-doing approach).

8.23 Different stakeholders may find it more attractive for AEMO to operate with more or with less flexibility. This may also depend, in part, on the wider economic incentives facing AEMO (whether it operates as a for-profit or a not-for-profit entity[214]), and how the rules that AEMO should follow are set (e.g. whether a regulatory authority is well placed to identify ex-ante the socially optimal amount of cost that AEMO should incur in relation to ESS).

212 A material change to the overall market design, or a new product definition is likely to have a significant impact on market participants. Conversely, the risk is less relevant in situations where the change is likely to have limited effects on market participants (e.g. adjusting the procurement target below a materiality threshold, or expanding eligibility criteria to allow for new technologies).

213 This may be for a limited period time, for example prior to formal rules being amended.

214 In this report we have assumed that AEMO continues to operate as a not-for-profit entity.

8.24 In practice, it is unlikely that all stakeholders would agree on a single level of discretion that AEMO should have. Therefore, a balanced approach, where AEMO discretion varies depending on the specific circumstances, may be the most acceptable to a broad spectrum of stakeholders. In such an approach, AEMO might have a degree of flexibility to make specific adjustments without any ex-ante external review or approval, while other changes would be subject to more extensive scrutiny and formal regulatory consultation and approvals. For example:

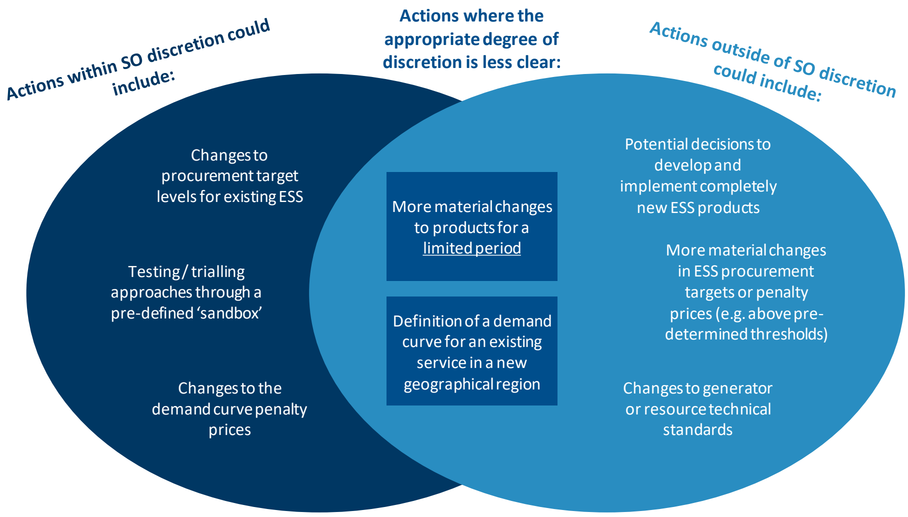
- Adjustments that do not require ex-ante external approval could include changes to procurement targets for existing ESS and/or changes to the demand curve penalty prices – both within specified ranges[215] and subject to an ex-post review process and provisions for potential after-the-fact revisions. This type of discretion would allow AEMO to fine-tune the design on an ongoing basis, and particularly in the early years.
- Conversely, other AEMO decisions, such as decisions to develop and implement completely new ESS products, may require considerable external scrutiny. There might also need to be tighter rules in place for more material changes in ESS procurement targets or penalty prices (e.g. above pre-determined thresholds).

8.25 In addition, there may be decisions where the appropriate degree of discretion is less clear at this stage and therefore may need to be examined further with relevant stakeholders. For example, it is unclear how much discretion would be reasonable for AEMO to have regarding the definition of a demand curve for an existing service in a new geographical region, or more material changes to ESS products which may only permitted for a limited period. This may need to be explored further and appropriate limits may need to be imposed.

8.26 The examples of areas where more or less discretion by AEMO may be appropriate are illustrated in Figure 8-1 below.

215 This would only be relatively non-contentious if the pre-specified range was relatively narrow. By contrast, changing the procurement target by a significant amount (outside of the specified narrow range) may be considerably more contentious.

Figure 8-1: Illustration of SO discretion for types of ESS design decisions



Source: FTI analysis.

Role of networks

8.27 Within the NEM, each state is served by a TNSP, regional network monopolies which "*link generators to the 13 major distribution networks that supply electricity to end use customers.*"[216] TNSPs build, operate and maintain transmission networks and may also be obligated to undertake investments to respond to shortfalls (identified by AEMO) in certain services.

8.28 As with the role of AEMO discussed in the previous section, there is an information asymmetry between TNSPs and regulatory authorities:

- On the benefits side, TNSPs have an intimate knowledge of the networks they own and operate, as well as how their obligations can be delivered.
- However, on the costs side, it is challenging for external observers to ascertain whether the obligations have been delivered at least cost.

8.29 Moreover, TNSPs tend to have commercial incentives that drive a preference for capex solutions, which allow for a regulated return on RAB, over any opex solutions. In delivering any system services, this bias can result in decisions that are not in the long-term interests of consumers.

216 AEMC, Transmission Frameworks Review Fact Sheet, 11 April 2013 (link), page 2.

8.30 In the case of TNSPs, this asymmetry of information and the bias towards capex-heavy solutions is primarily resolved through standard regulatory arrangements, whereby costs incurred by TNSPs are scrutinised through a regulatory review process (such as the RIT-T process). At first sight, TNSPs in the NEM therefore seem to have relatively limited flexibility in how they deliver system services:

- They are obligated to take action in response to shortfalls of system services (e.g. inertia and system strength) identified by AEMO, but they do not initiate this process; and
- In assessing options for mitigating the shortfall, they are constrained by the RIT-T rules and processes.

8.31 However, in practice, TNSPs have some degree of flexibility in procuring system services: for example, they can discharge their obligations by entering into bilateral contracts with generators and/or by making regulated investments.

8.32 Moreover, this process does allow for a degree of discretion in how TNSPs undertake the RIT-T assessment. For example, when considering whether to mitigate a shortfall in inertia and system strength, TNSPs need to compare the network solution (e.g. investment in synchronous condensers or potentially augmenting transmission lines) and non-network solutions (contracts with generators), to identify the least cost credible option. In making this comparison, the TNSPs can exercise discretion[217] in articulating the requirements for the contracts with generators. For example, TNSPs could inflate the costs of non-network solutions (that TNSPs do not provide) by imposing stringent requirements, such as a need to be continuously available to provide the service and severe penalties for non-delivery under those contracts. This would then have the effect of casting network solutions (that TNSPs do provide) in a more favourable light.

[217] This is one manifestation of the asymmetry of information between TNSPs and regulatory authorities.

8.33 Going forward, and in light of the asymmetry of information and capex bias, the regulatory framework needs to consider whether there is a risk that TNSPs may incur excessive costs. The appropriate regulatory framework needs to find a balance between “too much” and “too little” flexibility, as there are risks associated with both ends of the spectrum:

- **Too much flexibility,** with little external scrutiny and stakeholder engagement, could lead to unnecessarily high consumer costs if the best-quality solution is not identified, or if unnecessarily conservative / risk-averse investments are undertaken.[218]
- Conversely, a **lack of flexibility**, where TNSPs operate within a ‘straitjacket’ of excessively prescriptive rules, could lead to unnecessary delays in investments that would increase costs to consumers.

8.34 The options for augmenting (or constraining) TNSP flexibility that could be considered in the NEM depend on the factors described above. Some options include:

- Adjusting the incentive regime for TNSPs to reduce the perceived risk of bias towards capex solutions. This has been tested in other jurisdictions through the application of a “totex” approach to regulation, which intends to make network companies indifferent between capex and opex solutions. This could lead to a higher degree of trust that the TNSP will reach the “right” decisions in choosing between capex and opex investments. However, this approach may not fully mitigate the risk that TNSPs may be incentivised to overstate the need for an investment and in so doing the benefits of the selected solution (whether it is an opex or a capex solution).
- Adjusting the RIT-T test, for example by allowing third parties to put forward proposed solutions to identified shortfalls in system services (instead of these solutions being framed by TNSPs). Critically, the adjudication on the least-cost credible options would be made by an independent party, rather than by TNSP.

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[218] This risk can arise, for example, in deciding whether to make a network investment (with a long lifetime, often up to 50 years) or deploy a non-network solution (which can rely on a much shorter contract period, say less than 10 years). This means that a network investment leads to a greater risk of inefficient decisions in hindsight (and of stranded assets), which are more acute in the context of highly uncertain future system needs (with respect to technology cost, resource cost, forecast consumer demand, etc).

- Increasing the cross-border coordination among TNSPs to ensure that investments (both network and non-network) are considered for the benefit of the NEM as a whole (even though the RIT-T already aims to do this).
- More generally, centralised planning by AEMO, through the ISP, can be used to facilitate a degree of coordination between investments (both within and across NEM regions) as necessary to deliver system security.

Role of standards

8.35 Some of the market design responsibilities relate to setting technical standards. In the NEM, this responsibility sits with AEMC and the Reliability Panel, who are obligated by the NER to "*make determinations, guidelines, standards and settings*".[219]

8.36 Technical and performance standards could also be used to augment flexibility of the system. In practice, this would mean that standards could change either more quickly, with less external scrutiny, or both. Specific examples of flexibility that might be beneficial include:

- Relaxations of network codes in limited circumstances to encourage innovation, trialling and testing of new designs or technologies;
- Introduction of new rules to help accelerate deployment of necessary technologies (e.g. to reduce the system sensitivity to higher RoCoF); or
- Introduction of new requirements on the existing fleet of resources (this has already been applied in the NEM – for example, the recent MPFR rule applies to all scheduled and semi-scheduled generators, new and existing[220]).

8.37 There is no single best practice for changing technical and performance standards based on the international experience. As discussed in the rest of this section, the appropriate degree of flexibility again depends on the wider circumstances, but other jurisdictions (such as GB and some of the US ISOs) allow for some flexibility in changing the technical standards.

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219 AEMC, Electricity guidelines and standards website (link). Accessed 30/06/2020.

220 AEMC, National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, 26 March 2020 (link).

8.38 The appropriate degree of flexibility in terms of setting the technical and performance standards depends on whether:

- A lack of flexibility could lead to unnecessary delays in investments that would temporarily increase costs to consumers; and
- Too much flexibility could also lead to unnecessarily high consumer costs if it bypasses external scrutiny and stakeholder engagement and therefore the best-quality solution is not identified.

8.39 As a practical example, in the US, markets are subject to technical regulation in addition to economic regulation. The North American Electric Reliability Corporation ("**NERC**") is the regulatory authority at the national level, and aims to "*assure the effective and efficient reduction of risks to the reliability and security of the grid*".[221] Regional reliability organizations, such as the Western Electricity Coordinating Council and the Northeast Power Coordinating Council, operate at a regional level. Legislation introduced following a widespread Northeastern blackout in 2003 gave the Federal Energy Regulatory Commission ("**FERC**") a degree of authority over these reliability organisations.

8.40 The US reliability regulators establish minimum standards which ISOs must at least meet (but may choose to exceed). However, ISOs can implement new products without the approval of the reliability organisations if the new product does not adversely impact the ISO's ability to meet reliability standards. Examples of changes which do not require the approval of reliability regulators include increases to reserve levels and the implementation of ramp dispatch designs.

8.41 In GB, Ofgem, the energy regulator, produces a variety of technical codes and standards that market participants must comply with, including:[222]

- **Connection and Use of System Code:** This "*constitutes the contractual framework for connection to, and use of, the national electricity transmission system.*" The methodology used to calculate charges for connection to the system is also defined within the code;[223]

221 NERC, About NERC (link). Accessed 28/05/2020.

222 Ofgem, Technical Standard website (link). Accessed 30/06/2020.

223 Ofgem, Connection and Use of System Code website (link). Accessed 30/06/2020.

- **Grid Code:** This outlines the technical requirements for connecting to and using the National Electricity Transmission System. Compliance with the Grid Code is a requirement of the Connection and Use of System Code.[224] NGESO is the code administrator, meaning it is responsible for maintaining the code and overseeing any proposed changes. Additionally, any change to the Grid Code must be reviewed by the Grid Code Review Panel, and approved by the Panel or Ofgem. The Review Panel is comprised of representatives from a wide variety of organisations, including Ofgem, the Department of Business, Energy and Industrial Strategy, NGESO, generators and consumer interest groups.[225]
- **Security and Quality of Supply Standard ("SQSS"):** This lays out "*the criteria and methodology for planning and operating the National Electricity Transmission System.*"[226] As with the Grid Code, NGESO is the administrator and therefore maintains the code and oversees any proposed changes, which must also be approved by a Security and Quality of Supply Standard Review Panel (of a similar composition to the Grid Code Review Panel) or Ofgem. The SQSS Governance Framework sets out how the Panel is established and composed, in addition to the procedure for modifying the code.[227]

8.42 However, in specific circumstances, certain parties may be awarded a derogation from particular aspects of the Codes.[228] For example, this may occur when complying with a particular Code results in an inefficient outcome. Market participants must apply to Ofgem for such a derogation, which must include a quantitative assessment of the impact of the proposed derogation. Interestingly, under some circumstances NGESO (as opposed to the regulator) may also grant certain derogations through the Connect and Manage process.[229]

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224 NGESO, Grid Code website (link). Accessed 30/06/2020.

225 NGESO, Grid Code Panel Meeting and Documents website (link). Accessed 30/06/2020.

226 NGESO, Security and Quality of Supply Standard website (link). Accessed 30/06/2020.

227 NGESO, Security and Quality of Supply Standard Governance Framework, 1 April 2019 (link).

228 Ofgem, Derogations from Standards website (link). Accessed 30/06/2020.

229 Ofgem, Security and Quality of Supply Standard website (link). Accessed 30/06/2020.

8.43 The good regulatory practice therefore indicates that standards and technical performance requirements are commonplace in other jurisdictions, but that there is often a degree of flexibility through which the regulators and/or the SOs can exercise discretion in order to deliver more efficient outcomes.

C. Checks and balances

8.44 In the previous section we identified the potential benefits of increasing the flexibility of the regulatory regime for ESS. A more flexible regulatory regime that supports and encourages innovation, technology neutrality and long-term improvements to the ESS design is likely to be the interest of consumers.

8.45 However, we also articulated the risks associated with making the regulatory regime more flexible. The risks were driven, among others, by the incentives facing the relevant parties, as well as by the asymmetry of information and the difficulties in monitoring whether or not the ESS are being provided at an efficient cost.

8.46 This suggests that to deliver the benefits of a more flexible regulatory regime there need to be checks and balances in place to mitigate the downside risks of such flexibility. This may include:

- Embedded SO and TNSP incentives;
- Limiting SO discretion to tests and trials;
- Transparency requirements and procurement guidelines;
- Requirement for ex-post formalisation of any trials; and
- Cost controls to mitigate AEMO's expenditure.

8.47 Each of these are considered below in turn.

Incentives regime and oversight

8.48 To ensure that responsible entities, such as AEMO and NSPs, are appropriately accountable to policy makers, suitable incentives (monetary, reputational or even legal) need to be in place. Such incentives play a dual role:

- First, in a static sense, they encourage parties to perform in line with the consumer interest (assuming that the incentives are aligned that way); and

- Second, in a dynamic sense, they help to reduce the information asymmetry between the decision makers (e.g. AEMO and NSPs) and the regulators over time. For example, by rewarding the entities for reducing their costs in the initial years of the incentive regime, the regulator gains better information about the efficient cost base of the entity, which can be reflected in the design of the regime (e.g. allowed revenues) in the subsequent years.

8.49 In turn, depending on the design of the incentive regime for the relevant parties (AEMO, TNSPs, or any others), there may be a case for more or less flexibility (or discretion that those parties may have).

- A well-designed and sharp-incentive regime that aligns the decision maker's actions with consumer interest would in principle favour more flexibility and discretion. Such a regime would be likely to deliver a high degree of trust that the party is likely to make the "right" decisions.
- Conversely, a weaker[230] incentives regime, that creates a risk of potential misalignment between SO and consumer interests, would favour less flexibility and discretion, in part because there would be less trust in the decision makers.

8.50 One potential design is where the SO, TNSPs or other relevant decision makers face a clear set of transparent (and sufficiently strong) commercial incentives that are aligned with the interest of network users, such that there is less of a need for monitoring and rewarding/penalising the parties involved for behaviour that may or may not be desirable. **For-profit arrangements** or **ex-ante commercial incentives** are one type of a design that can provide sharp economic incentives for entities to behave in a particular way.

8.51 However, there are significant challenges associated with the development of for-profit regimes, particularly for system operators.

[230] This refers to situations where a non-profit ISO cannot be financially incentivised to deliver the right outcomes for consumers. Alternative incentives, such as management incentives are imperfect and tend to lead to inefficient decisions by the ISO – e.g. undue conservativeness in operating the power system.

8.52 The significance of the challenges is demonstrated by the failure of other international jurisdictions to establish such a regime on an effective, long-term basis. For example, GB's Balancing Services Incentive Scheme ("**BSIS**") used to be in place during 2010s, in which the GB SO was rewarded or penalised for underspend or overspend against an ex-ante target via a sharing factor. However, this regime was found not to be workable, in part due to the inability of the relevant parties to accurately model outcomes ex-ante, and also due to issues of information asymmetry. The BSIS regime was therefore discontinued.[231]

8.53 In light of the difficulties associated with the for-profit incentives, an alternative approach may need to be considered based on a **not-for-profit arrangement** for the system operator. This is indeed the approach currently in place for AEMO. Similarly, US ISOs are largely non-profit organisations and typically have management incentives for achieving targets set by the independent board.[232]

8.54 The lack of commercial incentives, however, means that some degree of oversight remains necessary to ensure that the parties take actions that are in line with consumer interest. One such alternative framework would be to evaluate the performance of the relevant authority (e.g. AEMO, Reliability Panel or AEMC) subjectively, such as through a "scorecard". Based on the ex-post evaluation, the authority may be rewarded or penalised for its prior performance. For example, in GB, the BSIS regime (discussed above) was replaced in 2018 with exactly this type of arrangement, where the performance of the SO is evaluated ex-post through a "scorecard".

8.55 This approach could, in theory, motivate the parties to take actions that are in the interest of network users. However, insofar as it is challenging to fully align the "scorecard" criteria with the interests of network users, this increases the risk of the SO not taking actions that are aligned with the interest of network users. Under this framework, less SO discretion (and/or more regulatory oversight) could be appropriate.

231 BSIS is outlined in more detail in Appendix 2 below.

232 In the NEM, this design could be implemented as management incentives for AEMO senior team.

8.56 A variant of this approach is a regime where the actions of AEMO, TNSPs and other relevant parties are closely monitored by a third party. For example, instead of being subject to AER's oversight, AEMO might operate under a form of standard set by the Reliability Panel (or another party). Rather than rely on an incentive regime, this approach would require AEMO's actions to be tightly defined and guided by performance standards. This approach is currently deployed in the NEM for the system restart standard which defines the precise timeframes within which AEMO must restore the system and also places limitations on the costs incurred.[233]

8.57 This approach should, in theory, ensure that AEMO's performance and the costs associated with the provision of services are controlled and align with the interests of consumers. However, in practice, the requirement for "correct" performance levels and costs to be identified ex-ante is highly challenging and would necessarily result in very high informational requirements on the authority overseeing AEMO's costs. For example, the Panel (or other decision-making party) is unlikely to be able to identify the "correct" standards or costs to be incurred ex-ante for all ESS at all times. This is because the Reliability Panel (or any other entity) is unlikely to have sufficient information to set the efficient cost thresholds and the associated trade-offs correctly.

8.58 Moreover, even if the performance levels were set "correctly", the SO may still have an incentive to act conservatively in meeting the performance standard. This is because the SO faces the risk of a reputational penalty if it fails to meet the standard, but may not be penalised (or be penalised as much) for incurring large costs in outperforming the standard (again, due to the asymmetry of information on costs between the regulators and AEMO, as discussed earlier in this section).

Tests and trials

8.59 It is likely to be possible to design and implement fundamental changes to the procurement and/or scheduling of ESS based on "desktop" analysis, consultations and reviews of international precedents. However, the understanding of the impact of the change, and the quality of the decision, may be improved if there is empirical, NEM-specific evidence available.

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[233] AEMC, Review of the System Restart Standard Final Determination, 15 December 2016 (link), page 3.

8.60 To gain practical experience with new approaches to procurement and/or scheduling of ESS, and to better understand their benefits, it may be desirable to implement them in a "live" environment. In practice, this means that relevant parties may need to have the ability to test or trial new ideas and concepts, perhaps on a limited scale or for a defined period of time, and with appropriate checks and balances, in order to gather this evidence before substantial effort is put into a more fundamental re-design of the arrangements.

8.61 One option to reduce the upfront costs and gain a better understanding of the benefits (or unintended consequences) of the changes is to test and trial those changes first. This can be done by restricting their geographical scope (say, to a small region), the duration (possibly a set number of months or years), or the range of participants.

8.62 Additionally, the emphasis on testing and trialling of new products and services on a small scale, as opposed to introducing previously untested changes to the whole market, provides the SO with discretion and flexibility to create new products and services and encourages innovation, without exposing the wider market to the risk associated with the discretion.[234] Some of the advantages and disadvantages of a test-and-trial approach are set out in Table 8-1 below.

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234 In September 2019, AEMC recommended the implementation of a regulatory sandbox in the NEM. This framework would allow participants to "*test innovative concepts in the market under relaxed regulatory requirements at a smaller scale on a time-limited basis with appropriate safeguards in place.*" Source: AEMC, Regulatory Sandboxes – Advice to COAG Energy Council on Rule Drafting, Final Report, 26 march 2020 (link), page i.

Table 8-1: Advantages, disadvantages and mitigations of trial-and-test mechanisms

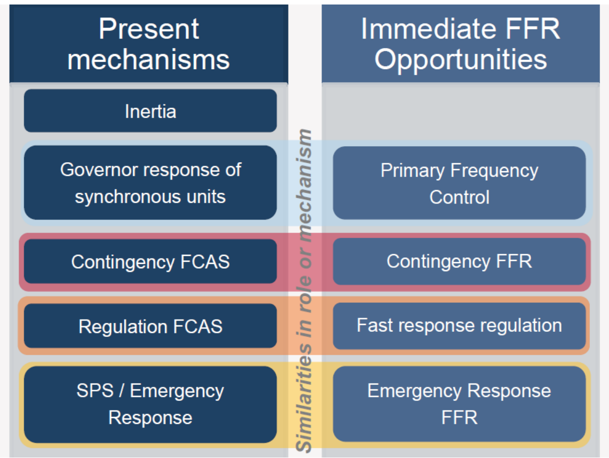
<table>
<tr><th>Advantages</th><th>Disadvantages</th><th>Mitigations</th></tr>
<tr><td rowspan="4">- Learning by doing where NEM impact is uncertain without practical experience, or if there is a risk of severe unintended consequences
- Limited upfront costs before full commitment
- Encourages innovation in a controlled environment, without affecting the wider system security
- Reduced stakeholder aversion to changes if viability is demonstrated through pre-trial
- Option to amend or even discard the change if trial identifies insurmountable difficulties</td><td>Full impacts may remain unknown if the trial is perceived as short-term, unstable and provides a weak price signal.</td><td>Design trials as realistically as possible and encourage participation.</td></tr>
<tr><td>Consumers risk paying for “pet projects” that do not benefit consumers.</td><td>Require objectives, success criteria and hypotheses being tested to be clearly articulated.

Use ex-post review processes, and reputational incentives, to act as a control.</td></tr>
<tr><td>Perception of instability in the design of the system.</td><td>Transparent communication on the drivers, process and implementation of any trials.</td></tr>
<tr><td>Participants may gain undue advantage from the trial learnings.</td><td>Requirement to widely share the learnings of any trials with stakeholders.</td></tr>
</table>

Source: FTI analysis

8.63 This approach could be considered in the NEM for changes such as the introduction of a Fast Frequency Response (“**FFR**”) service. This service seeks to complement the existing suite of FCAS, in up to three different potential ways: contingency FFR, fast response regulation and emergency response FFR, as summarised in Figure 8-2 below.

Figure 8-2: Relationships between existing frequency control services and FFR



Source: AEMO, Fast Frequency Response in the NEM. Working Paper, August 2017 (link), page 3.

8.64 Running a trial or a test for one or more of the FFR types would appear to be reasonable if:

- There was demonstrable evidence that the current suite of FCAS fails to meet specific needs of the system, and that these needs could credibly be met through the new proposed service.
- The ex-ante cost-benefit analysis of such changes was very uncertain; for example, if the expected range of benefits was so wide that it would be plausible that the FFR could be net-negative or net-positive for consumers.
- It was uncertain which one (or more) of the three proposed types of FFR was the optimal approach for consumers.
- There were clear hypotheses that the trial would seek to test, such as whether faster frequency control could be delivered at lower cost or more efficiently compared to the FCAS; or whether FFR would reduce power flow constraints imposed by risks of high RoCoF levels.[235]
- There was a credible expectation that new innovative approach could be developed to meet the need for FFR, evidenced for example through discussions with stakeholders.
- There was limited credible expectation that the FFR would lead to major unintended consequences that would cause harm to the system.

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235 AEMO, Fast Frequency Response in the NEM. Working Paper, August 2017 (link), page 3.

- The trial could be tested in a safe manner that would not compromise the operation and security of the wider NEM.

8.65 Indeed, AEMO has already initiated trials of FCAS and FFR services to be delivered by wind and solar PV.[236]

8.66 There is a wide range of examples of system services being trialled on a temporary basis in various international jurisdictions. Selected examples from GB and from the US, which could serve as potential precedents for the NEM, are outlined in Box 8-1 below.

Box 8-1: International examples of tests and trials

GB experience

In GB, NGESO operates under a regulatory framework in which it is encouraged (although not financially incentivised) to introduce competitive processes where possible and to drive innovation.[237] It has been able to "trial and test" new services and a number of ancillary services have evolved over time to better meet the needs of consumers.

For example, following an announcement in May 2018, NGESO has been running a number of "pathfinding" projects, which are designed to allow the SO to *"explore, experiment, and learn"* and to refine its frameworks for addressing system needs.[238] Each project aims to address a specific system need through the creation of a new commercial product, which NGESO procures via a competitive tender. The projects are undertaken on a small scale, with the existing market mechanisms and procurement channels continuing to operate, minimising the risk to the wider system associated with trialling innovative products.

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236 For example, AEMO collaborated with ARENA and Neoen on a demonstration of frequency control services at the Hornsdale 2 wind farm. Source: AEMO, Hornsdale Wind Farm 2 FCAS Trial Knowledge share paper, 25 July 2018 (link).

237 Ofgem, ESO Roles and Principles, 23 February 2018, (link).

238 National Grid ESO, Network Options Assessment 2018/19, January 2019 (link), page 15.

From the NEM perspective, the **system stability pathfinder project,** which aims to create a commercial product to promote system stability[239] in the context of declining synchronous generation, may be most interesting. System stability, as with system strength in the NEM, is not an easily measurable product. Therefore, rather than attempt to procure it directly, NGESO specified that participants were required to provide three services that are known to contribute positively to system stability: inertia, fast active dynamic voltage support, and increased short circuit levels (without producing bulk energy).[240]

Additionally, in February 2017, Ofgem launched a **regulatory sandbox** service designed to enable innovators to trial new products, services and business models that could benefit consumers, under a lighter regulatory oversight. The Ofgem experience with the regulatory sandbox provided helpful learnings for AEMC in designing a similar sandbox for the NEM (as discussed in footnote 234). Based in part on the review of the international experience, the AEMC 2019 review recommended that "*a regulatory sandbox toolkit should be established to assist innovative proof-of-concept trials to be carried-out*".[241]

US experience

In general, US ISOs are not able to establish and procure new products and services without prior regulatory approval from the relevant body (PUC for ERCOT, FERC for other ISOs), with Ontario's IESO also faces similar restrictions. The ease and speed with which new services and products can be approved is dependent on the level of support rendered by the proposal. If there is widespread support for a change from stakeholders, a change can be approved and go into effect relatively quickly (e.g. 60 days after it is filed). However, if a proposal is controversial and does not enjoy widespread support, it may take several years to receive approval from the regulator.

239 NGESO define stability as the stability of frequency and voltage, and the ability of a user to remain connected to and to act to support the system during normal operation, during a secured fault or after a secured fault, without any restriction in doing so that would relate to the strength of the system at that time. Source: NGESO, Stability Pathfinder RFI, 19 July 2019 (link), page 17.

240 NGESO, Stability Pathfinder Phase One Outline Plan, 21 October 2019 (link), page 6.

241 AEMC, Final Report Regulatory Sandbox Arrangements to Support Proof-Of-Concept Trials, 26 September 2019 (link), page 9.

For example, in October 2019, MISO filed a proposed revision to its Open Access Transmission, Energy and Operating Reserve Markets Tariff that would create a new 30 minute Short-Term Reserve product.[242]. This would replace the current practice of committing out-of-market units, which MISO argued was inefficient and costly. On 31 January 2020, FERC concluded that MISO's proposal was "*just and reasonable*"[243] and therefore accepted the proposal, which is to become effective from December 2021. However, when CAISO in 1999 proposed an amendment to its pricing tariff in order to avoid additional constrained down payments under its zonal pricing design, it was met with widespread resistance by stakeholders, who argued that the proposal would have treated new and existing generators unequally.[244] FERC went on to reject the proposal and it was therefore never implemented.

While the creation of new services and products requires prior regulatory approval, US ISOs are able to modify aspects of some existing services. For example, NYISO is able to modify its ORDC's if a short term reliability or operational need is identified.[245] Additionally, NYISO has previously been afforded significant discretion by its regulator to make unilateral changes to the market for a period following significant market design changes, in order to "*address market design flaws, transitional abnormalities and severe operational difficulties*" that might surface after the markets became operational.[246]

More detail on all of these examples in available in Appendix 2.

Transparency and procurement guidelines

8.67 The procurement of ESS should be transparent for relevant parties involved, in order to encourage participation and enable monitoring of outcomes. In the absence of transparency, investors are unlikely to be comfortable committing to long-term investments, or may only be willing to do so at a high cost (by pricing in the perceived uncertainty).

8.68 The transparency requirement applies to all processes that may lead to the provision of ESS, as set out below:

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242 FERC, Docket No. ER20-42-000, 31 January 2020, (link).

243 FERC, Docket No. ER20-42-000, 31 January 2020, (link), page 13.

244 FERC, Docket No. ER99-3339-001, January 31 2000 (link).

245 NYISO, Ancillary Services Manual, May 2020 (link), page 69.

246 United States Court of Appeals, Case #06-1027 Document #1086980, 18 December 2007 (link), page 4.

- If procuring ESS through market-based mechanisms, it is important that the "need" for services and the specific technical requirements are clearly articulated, so that prospective parties can participate in the market effectively. There also needs to be clarity on the selection process so that prospective providers of services understand ex-ante how they would be evaluated should they choose to participate. Finally, there also needs to be a timely communication of the outcomes of any selection process – whether competitive (such as a tender), bilateral or mandatory (e.g. through technical standards).
- If procuring ESS through non-spot-market mechanisms such as regulated investments by TNSPs, there needs to be transparency on the entire end-to-end process. There needs to be clarity on when and who can initiate the identification of a "need" for a regulated investment (so that non-TNSP parties understand the risks of such investments being made, and potentially impacting their own commercial outcomes), as well as how such an assessment is performed (e.g. through a RIT-T type test). It may also be necessary for the process to be transparent on how alternative non-regulated solutions can be put forward by interested parties as alternative credible options.
- Finally, there also needs to be transparency on the mechanics of changing technical and performance standards, particularly if these changes are applied retrospectively to committed investments. This includes the need to undertake impact assessments, consultations and an evaluation of any unintended consequences of the potential changes to the relevant standards.

8.69 The procurement of ESS is likely to be more transparent if the system operator follows clear guidelines, based on broadly accepted principles, and is held accountable to those guidelines. For example, NG ESO follows a series of Procurement Guidelines, which provide the broad principles by which NG ESO will act. These guidelines "*are not prescriptive of every possible situation that [NG ESO] are likely to encounter, but rather represent a generic statement of the procurement principles [NG ESO] expect to follow*".[247]

[247] National Grid Electricity System Operator Procurement Guidelines, effective from April 2019, (link).

8.70 There may be two additional transparency requirements needed for services that are being "trialled-and-tested" in terms of information sharing.

- **Information sharing.** To maximise the benefits to consumers from the learning experience of testing a new product or approach, it may be appropriate to require, ex-ante, that the parties involved in the trial publish the outcomes and conclusions (both positive and negative), for others to learn from. For example, in GB, the regulator Ofgem funds selected parties through the Electricity Network Innovation Competition ("**NIC**") framework, which supports network companies to "*run trials of new technology and different commercial and network operating arrangements*", subject to the requirement that all learnings are widely shared across the industry.[248]
- **Time limits.** Where the approach is intended to be tested for a time-limited period only, this should be signalled to the market in advance, to provide visibility and allow market participants to make appropriate decisions. For example, NGESO's procurement guidelines state that the SO must publish the timelines of any trials it undertakes involving additional provider contracts.[249]

Ex-post formalisation

8.71 The regulatory framework may also need to include a mechanism that ensures that system services that have been tested (perhaps under a discretionary rule), and have been shown to be attractive, are eventually formalised. The expectation that any "shortcuts" that are taken under the guise of a trial-and-test approach would eventually need to be formally reviewed and, if approved, would act as a control mechanism to prevent undesirable behaviours from emerging.

8.72 In addition, the process of formalising the system services (e.g. through being written into rules, or standards) is likely to further support market participation, and hence investability, by attracting parties that might otherwise be reluctant to provide a non-formalised service.

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[248] Ofgem (2019) Decision on the 2019 Gas and Electricity Network Innovation Competitions (link). Ofgem explain that "*a key feature of the NIC is the requirement that project learning is disseminated, in order for customers to gain a significant return on their funding through the broad rollout of successful projects, and the subsequent delivery of network savings and/or carbon and environmental benefits. Even where projects are implemented and deemed unsuccessful, network licensees will gain valuable knowledge that could result in future savings in network costs.*"

[249] National Grid Electricity System Operator Procurement Guidelines, effective from April 2019, (link), page 11.

Cost controls

8.73 For certain services, a form of cost control may be required to ensure that AEMO does not face excessive procurement costs as a result of market participants leveraging market power. For example, the highly locational nature of system strength limits the scope for competitive pressure to reduce prices and deliver efficient market outcomes, providing grounds for a form of cost regulation.[250]

8.74 A potential solution could be to include price caps, set either as an absolute price or as a percentage above cost, in contracts between AEMO and providers of the service. A price cap could also be set for market-based procurement, although market-based procurement is generally not suited to services where levels of market power is a concern.

D. Maintaining investability

8.75 The previous two sections considered how the regulatory regime can become more flexible (and thus create benefits for consumers), while limiting the downside risks through a suite of checks and balances. The final component that needs to be considered in finding the right combination of flexibility relative to the checks and balances is whether the regulatory regime design is likely to deliver appropriate investment signals to facilitate the provision of ESS in the long term.

8.76 Strong investment signals are necessary for market participants to undertake the necessary investments in resources that are able to provide ESS. This is particularly important if policy makers perceive a risk that there may not be sufficient investment made in such resources, or that such investment may not be made in a timely manner.

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[250] This particular concern has materialised in South Australia: ElectraNet argued that it was uneconomical to contract with existing gas-fired generators to provide system strength, which resulted in AEMO issuing directions instead. ElectraNet then argued that "*Installing synchronous condensers on the transmission network is the most efficient and least cost solution in the short to medium term*". (ElectraNet, Addressing the System Strength Gap in SA, Economic Evaluation Report, 18 February 2019, link, page 3). However, as discussed in ¶8.32 above, we recognise that TNSPs would have an incentive to reach this kind of conclusion in order to cast network solutions (that TNSPs do provide) in a more favourable light.

8.77 This is the case for all ESS options explored in this report: AEMO-driven, TNSP-driven or standards-driven arrangements. In this section we explore how investability can be maintained through delivering price signals (including how risk allocation affects investability) and through an appropriate balance between stability and flexibility.

Delivering price signals

8.78 Different ways in which system services are procured can lead to very different investment price signals. As discussed in Section 6, there may be circumstances where RT spot market investment signals for resources to provide specific services may not be sufficiently strong to trigger adequate investment (e.g. if the prices are volatile and unpredictable, or if the prices are too sensitive to small surpluses in the supply of a particular service).

8.79 Fundamentally, such price volatility indicates that there is an inherent risk involved in making the investment because it is not certain, ex-ante, whether the prices will be sufficient to recover the investment costs (which are much more certain). This risk needs to be borne but someone in the market, and the exact risk allocation is a key feature of the market design. In Box 8-2 below we examine the options for allocating the risks associated with an illustrative investment and the merits of the different approaches.

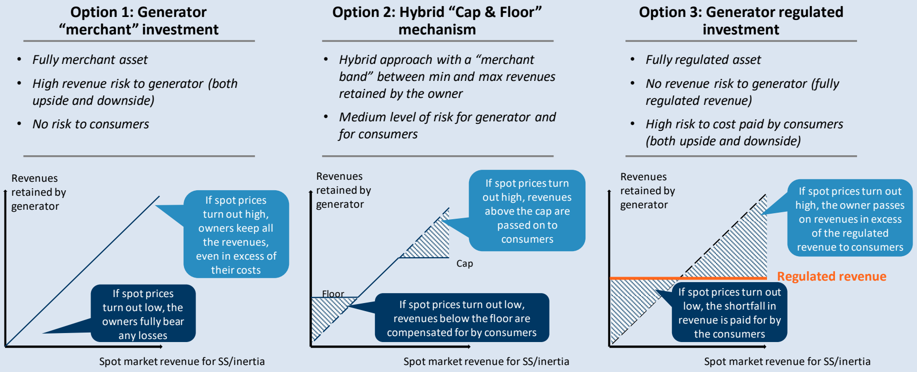
Box 8-2: Risk allocation options for an illustrative investment

In this case study, we consider a stylised example of a gas-fired generator that faces a decision as to whether to make a relatively low-incremental-cost investment to gain the technical capability to operate in synchronous condenser mode. This capability would, in turn, enable the generator to provide inertia and system strength at a relatively low cost, without injecting energy.

In this stylised example, the primary risk that the generator faces is that it does not know (despite spot price signals that may exist in the market), ex-ante, how much revenue it is likely to earn from the spot price for inertia and/or system strength. If the need for the services is high, the generator may be able to earn high revenues, but if the need for the services turns out to be low, the generator may only earn revenues that are less than the cost of the investment.

Crucially, this uncertainty of need for the asset, and the expected revenue volatility, is the same regardless of who makes the investment. However, depending on the regulatory regime in place, the risk can be allocated to different parties. As summarised in Figure 8-3 below, there are three potential high-level approaches. While by no means exhaustive, they help to map out the key issues in allocating risks among asset owners and consumers.

Figure 8-3: Range of risk allocation options (merchant, regulated and hybrid)



Source; FTI analysis

- In the left panel, the generator makes the investment and aims to recover the costs through the market price for the service. It thus bears the full "merchant" risk of the investment being economical or not. Consumers do not bear any of the risk that this investment might be loss-making.

- Conversely, in the right panel, the generator (or, equivalently, this could be a TNSP) makes the investment under a regulated regime where either (i) it is guaranteed a regulated revenue stream (regardless of how much value the asset earns in the market), or (ii) the revenue earned is structured as a CFD around the spot price for the service (see ¶6.19 *et seq.*). In this case, the owner of the asset (generator or TNSP) does not face any revenue risk,[251] but consumers are exposed to the risk that if the asset is loss-making, they will need to pay up for the shortfall in the market revenues.

- Finally, in the middle panel the risk is shared between the owner of the asset and consumers. There is a "merchant band" within which the owner of the asset is exposed to the market revenue risk, but there are limits to that. Below the floor, consumers contribute to the revenue retained by the asset owner (and thus bear some of the risk of asset being loss-making), while above the cap, consumers benefit from the upside.

There is no single "best" approach among the three above. Rather, policy makers need to select the risk allocation mechanism they consider to be appropriate to the relevant type of investment. In general, a good regulatory practice is to allocate these types of risks to the parties who are best able to manage them (see ¶4.16).

Second, and separately from the uncertainty of the market revenue discussed above, there is a risk that the investor may not incur costs efficiently (i.e. it may overspend). This risk is "automatically" mitigated in the merchant variant (left panel above) because the owner is strongly incentivised to minimise the costs. However, in the regulated world, there is the risk that consumers will overpay (through high regulated revenues paid to the owner of the asset) because the costs are inefficiently high. This can be mitigated in different ways:

- First, regulatory oversight and the application of investment tests can provide a degree of cost control, but in practice some cost inefficiencies are likely to remain due to the asymmetry of information between the regulator and the regulated entity. This may improve over time, due to the dynamics of the interaction with the regulator, who progressively uncovers better information about the efficient level of costs.
- Second, incentives may be developed for the regulated asset owners to behave in a manner that align their actions with consumer interest. Examples of this include penalties for under-performance, (or rewards for over-performance), or reputational penalties. However, in practice, these may also suffer from an asymmetry of information.
- Third, competitive mechanisms may be considered to introduce where bidders compete "for the market". In simple terms, prospective owners of the regulated asset submit bids for a regulated revenue stream, and the decision maker (who is assumed to act in the interest of consumers) selects the most cost-efficient bid.[252]

Source: FTI analysis.

8.80 As discussed in Section 6, spot prices for the provision of system services can provide useful operational and investment signals. However, as the strength of the signals may change over time, there may be a period of time during which spot-market-based investments may not be forthcoming, in which case alternative approaches may be considered. The following paragraphs consider three different routes to procuring system services (AEMO, TNSPs and technical standards) in turn.

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251 This difference in the risk profile of the investment may also be reflected in the appropriate cost of capital for the bearer of the risk. This is not explored in detail in this report.

252 This type of mechanism has been applied in Great Britain for the development of offshore transmission networks. Known as Offshore Transmission Operator ("**OFTO**") model, this regime features a competitive tender where prospective OFTOs submit bids for a regulated revenue stream that covers the cost of owning and operating the asset.

- Procurement of services by AEMO (e.g. through bilateral contracts or auctions) provides some investment signals and can support investments being made, but these are typically provided only to the contracted resources, but not other market participants. Resources that can provide the service but are not rewarded for it may not have the right operational signal (or may even retire inefficiently).
- Procurement of services via a regulated route by TNSPs does allow for efficiently incurred costs to be recovered, which provides an incentive for new investment to take place. However, there is no investment signal as such for TNSPs, other than a "need" identified by AEMO that the TNSPs are then obligated to fulfil through a regulated investment. In theory, this could be augmented by giving NSPs a greater role in identifying the need for additional investment, but the asymmetry of information between NSPs and the regulator/AEMO creates a risk that (i) NSPs will identify investments that are only relevant for the relevant region (but may not be most efficient NEM-wide); and (ii) NSPs will be unduly over-specifying (i.e. be overly cautious in defining) the need for the network investment. As with the AEMO contracts, non-contracted resources are not rewarded for the services and hence may not have the right operational signal (or may even retire inefficiently).
- Use of technical standards does not provide any investment signal to market participants. Rather, technical standards tend to "hide" the true costs of delivering a particular service and they create the risk of creating stranded assets. If changed very frequently, the technical standards may also undermine the investment signals from other parts of the system by increasing the uncertainty.

Balance between stability and flexibility

8.81 A stable regulatory regime (or at least a perception of stability) can provide stronger investment signals to parties, as market participants understand how the framework operates and what services are likely to be valued and compensated.

8.82 However, it is difficult to judge ex-ante whether a flexible regime would provide strong investment signals:

- One the one hand, if the regime is changed very frequently and is perceived to be unstable, this may increase uncertainty and thus deter market participants from making investment decisions that would be in the interest of consumers; but
- On the other hand, it is possible that the parties' ability to exercise discretion[253] could improve investability by providing assurance that the design will be able to adjust to changing system and market conditions.

8.83 There is therefore a need to balance the stability and flexibility of the overall framework, to ensure that provision of ESS is investable in the long run.

E. Regulatory Regime – Conclusions

8.84 A long-term regulatory framework for ESS needs to balance a number of sometimes conflicting objectives, to mitigate the risk of any unintended consequences and sub-optimal outcomes for the market overall.

8.85 The incentives that AEMO and TNSPs face in procuring ESS do not necessarily always align with consumer interest. In particular, the inbuilt tendency towards conservativeness by system operators, and the tendency towards investing in network (rather than non-network) solutions by TNSPs, might lead – if unchecked – to investments that are not cost-efficient. However, since it is difficult for external parties (e.g. regulators) to monitor and police these decisions, there are significant risks involved in giving AEMO and TNSPs "too much" flexibility in procuring ESS.

8.86 However, at the other end of the spectrum, giving the parties "too little" flexibility is also unlikely to align fully with consumer interest. This is because insufficient flexibility fails to stimulate innovation and does not allow the design of ESS procurement to adapt and meet the evolving system needs in a timely manner.

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253 This could be, for example, a degree of flexibility in terms of in making minor adjustments to the procurement framework, such as adjustments to the parameters of market-based ESS (targets and penalty prices) or the technical performance parameters.

8.87 A balance between these two ends of the spectrum may be, in practice, most acceptable to a broad range of stakeholders. Moreover, any flexibility that decision makers may have needs to be supported by a range of checks and balances to mitigate the downside risks. These may include: refinements to the commercial incentives faced by AEMO or TNSPs (or operation under the oversight of independent bodies such as the Reliability Panel), enabling flexibility within a controlled environment (such as testing and trialling), transparency requirements, the expectation that any exercise in flexibility would ultimately need to be formalised (albeit ex-post), strengthening the regulatory oversight by imposing cost controls (on potential providers of ESS to AEMO), or refining the RIT-T-type tests.

8.88 Overall, the right combination of flexibility relative to the checks and balances should be such that it provides appropriate investment signals to facilitate the provision of ESS in the long term. This combination is likely to depend on:

- The **credibility of the SO/TNSPs** in making changes to the ESS that are in the interest of consumers (which, in turn would depend on the incentive regime that they may be subject to).
- The **wider changes to the technology and market** landscape: faster changes in the environment may require a more “nimble” approach, which could involve expedited rule changes, temporary trial-and-test approaches and other mechanisms that balance the urgency of the need with the downside risks.
- The **magnitude of the proposed changes**: the higher the potential downside risks (and hence costs) to reliability and security, and the greater the potential impacts on the market or consumer costs, the more cautious the approach.
- The **wider learning value** of the potential change: approaches that can be leveraged and used by a wider body of stakeholders (e.g. where the learnings have to be socialised with the market) may be more attractive.

9. Roadmap

9.1 To "*promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity*",[254] the provision ESS in the NEM needs to evolve.

9.2 As set out in sections 2 and 3, there is a case to change the way in which system services are procured, driven by the gaps in the existing NEM arrangements (e.g. non-valued services), the recently observed power system outcomes (e.g. increasing shortfalls of some services), and, crucially, the ongoing transition towards a predominantly VRE-based system.

9.3 Sections 4, 5, 6 and 7 set out the principles for ESS procurement that are appropriate to bear in mind, explained that there is a wide range of design options that may be considered, and proposed different options for procurement and scheduling for different ESS in the NEM.

9.4 Section 8 described how an appropriate regulatory framework could be developed to support the design and implementation of any potential changes to the ESS.

9.5 In this section, we consider the roadmap for operationalising new ESS arrangements in the NEM, taking into account the wider market design reforms under consideration and the urgency of the need for change, while ensuring that rapid changes do not undermine the core objective of delivering a secure and reliable energy supply in the NEM. This roadmap assumes that there will be two broad phases of future NEM evolution: in the near term, the NEM will operate with a similar (albeit rapidly evolving) generation mix to today; but in the longer-term, the NEM is likely to operate in a VRE/IBR-dominated world, with an unknown mix of other resources and perhaps technologies used to meet balancing needs.

[254] National Electricity (South Australia) Act 1996, Version 1.7.2019 (link), page 43.

9.6 There is a spectrum of options that exist, ranging from a gradual, progressive approach to a one-off introduction, with more balanced approaches in-between, as explained in the following sections. A key decision to be made in the context of ESB Post-2025 market design work is where the NEM should be on this spectrum. This decision is likely to depend on the perceived balance of benefits, costs and risks associated with slower or faster changes, which are in turn driven by (i) the strength of vested interests and the appetite to move away from the status quo; and (ii) the speed of transition to a high-VRE system.

Progressive development approach

9.7 In a progressive development approach, each new system service is developed and added on an as-needed basis, and each modification to an existing service is also made as required, both to address issues as they progressively emerge and materialise. In practice, this could entail introducing a new operating reserve product in year T, or a new inertia product in T+3. The pros and cons of this approach are discussed below.

9.8 There are several advantages to this approach:

- First, it enables the speed and type of services procured in new markets to adjust as the NEM resource mix and system reliability needs evolve;[255]
- Second, it reduces the risk that the complexity of the overall design might result in long delays in implementing any improvements because elements of the design that are well understood can be implemented first. This would be particularly beneficial if services were initially procured in silos and later (if successful) incorporated into a wider co-optimised system. It also reduces the need for undesirable compromises in more complex elements of the design in order to speed up implementation of the simpler elements; and
- Third, it can enable the later development and implementation stages to benefit from insights gained from operational experience with the initial market changes. This not only includes the ability to refine later designs based on operational experience but also to adjust the priorities for development of additional product markets based on this experience. For example, it could be that the implementation of markets for operating reserves, ahead markets, or LMP pricing could materially reduce need for out-of-market commitments to meet system strength requirements in a particular region.

[255] The approach is also coordinated with wider system reforms taking place around a similar timeframe (e.g. RAMs, demand side participation, etc).

9.9 However, there are also drawbacks associated with this approach:

- First, a sequential development as well as implementation of the market design could create a siloed approach to ESS, and fail to deliver desired levels of co-optimisation. This approach also risks creating a path-dependency as the sequencing could influence the final combination of services, which may be sub-optimal;
- Second, a separate development of closely linked services can result in outcomes where design decisions made in isolation in the initial implementation process (for example, the design of the system software) may seriously compromise market design choices for services procured in later phases; and
- Third, potential cost from phased implementation of a design is that decoupled procurement can result in stranded software investment, i.e. procurement of software that is only used for limited number of years for the initial implementation, but later needs to be replaced with a completely new software system and even a new market design in order to fit with services implemented in later phases. These stranded costs can be reduced to the extent that existing software and processes can be used over the transition period, or if the software developed for use during the transition will continue to be used in some role after the new markets are introduced.

One-off introduction

9.10 Alternatively, at the other end of the spectrum, a one-off introduction approach would enable a more coordinated introduction of multiple services simultaneously.

9.11 There are several advantages to this approach:

- First, it would enable relevant ESS to be co-optimised, and relevant interlinkages to be fully considered prior to their introduction.
- Second, it would greatly reduce the potential for inconsistencies in the market designs and for stranded software investments (as described above). However, if only parts of the initial design perform as intended, while others require major changes because of continuing changes in system needs, there could still be a potential for stranded software investments (described above in relation to the progressive development approach) and potentially even more costly stranded investments. Both approaches present an unavoidable challenge: the lack of perfect foresight regarding the system end-state[256] mix of resources and technologies means that some market design and software procurement decisions will most likely not be optimal in retrospect.

9.12 However, there are also drawbacks associated with this approach:

- First, this approach risks creating delay to potential reforms (driven by the "lowest common denominator"). This could in turn result in sub-optimal outcomes for consumers if delays to urgent market design changes result in unnecessarily high costs.
- Second, it precludes any learning from the performance of the software and market designs implemented in the initial phases. Even with delayed implementation to accommodate the most complex parts of the design, there is no assurance that those elements will necessarily work as intended as the resource mix and system needs continue to evolve in ways that may not have been anticipated.

Balanced approach

9.13 A **balanced approach** falls between these two extremes. It would not attempt to implement all of the changes in a single project and timeline, but it would also not break the development and implementation down into a separate phase for every product. Rather this approach would seek to:

- Develop as much of the long run design is feasible;
- Identify particular system services that are so closely linked that it is efficient to implement them in tandem; and

256 There may not be an "end-state" as such, if the system continues to evolve over time.

- Identify other changes that have lesser interactions both in the market design and in the market software, and hence can be implemented in a separate project on a separate timeline.

9.14 The approach would also seek to develop as much of the design as the system operator has the foresight to be able to specify before procuring software, but also recognise where needs are too uncertain to be incorporated in a software specification and need to be developed and implemented separately.

9.15 The advantages of this balanced approach are that:

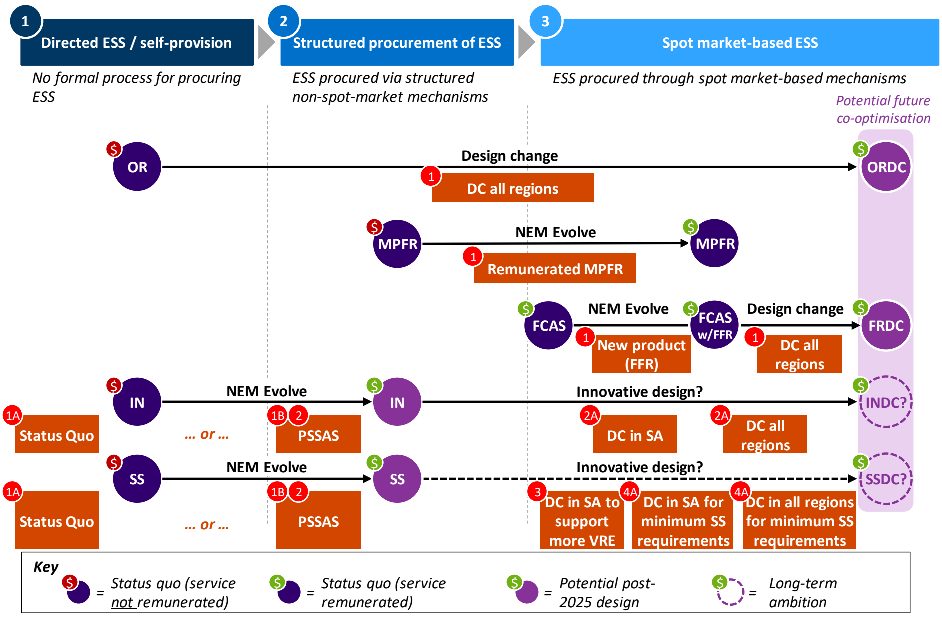
- First, it provides an opportunity to reduce the cost of procuring software that is only useful for a short period of time. The potential for stranded costs can be reduced both by combining some implementation steps but also by combining development. In this way, the software systems acquired to support the new market design have the capability to coordinate markets over a number of implementation phases, with the capability turned on as needed, and designed with the flexibility to accommodate changes in the role of the software system by adding or changing values in tables, rather than building a new software engine. However, there can be market design elements that will require a fundamentally different software engine if they are introduced separately. It is therefore important to identify these elements and introduce those elements in combination, rather than in sequence.
- Second, it mitigates the risk of inconsistent market design elements to the extent that the complete overall design is developed up front and the implementation sequenced.
- Third, it allows a degree of phasing in the implementation hence avoiding the delays and undesirable outcomes associated with trying to change everything at once. This includes the option of initially coordinating siloed markets for some system services before later (if successful) incorporating the separate markets into a wider co-optimised system or of introducing markets sequentially and relying on out-of-market procurement designs over the transition period.

9.16 The complexity of this balanced approach is that there is an art to choosing which market design elements and software systems interact so strongly that they need to be developed together, and which can be developed separately without much loss in efficiency or performance. Further complexity is added by the possibility of priorities evolving over time, which could lead to a need to continue adjusting the roadmap over time.

9.17 One potential variant of the balanced approach could involve the implementation sequence summarised in Figure 9-1 below and described in the following paragraphs. This roadmap would involve prioritising the most urgent changes to ESS (which are also less intertwined with other ESS) before progressing towards the less urgent (and more complex) ones.

9.18 For the avoidance of doubt, this roadmap focuses on the order in which changes might be considered. This means that not all the stages set out here would necessarily be implemented in the NEM by 2025 or even in the longer term. We envisage that before embarking on each stage, an impact assessment would be undertaken to consider relevant implementation issues and assess whether the continuation to the next stage is feasible and warranted. This process would be informed by the learnings from the previous stage(s) and based on the relevant principles for ESS procurement, as discussed in Section 4 of this report.

Figure 9-1: Potential balanced roadmap for ESS



Note: DC = demand curve; OR = operating reserves; MPFR = mandatory primary frequency response; FCAS = frequency control ancillary services; IN = inertia; SS = system strength.

Source: FTI analysis

9.19 As illustrated in Figure 9-1 above, in Phase 1, a spot market (based on the concept of demand curves) for reserves and FCAS would be developed across one or all NEM regions. MPFR would be explicitly remunerated, and FCAS may introduce a new product (e.g. FFR). In addition, during this phase, there may be two approaches considered for inertia and system strength:

- Either, as Phase 1A, the NEM would continue with the status quo of using an out-of-market commitment design based on AEMO directions;
- Or, as Phase 1B, a PSSAS design would be implemented to support additional AEMO commitments for inertia and system strength.

9.20 The choice between approaches 1A and 1B would be informed by how long it will take to implement the spot market (and the underlying demand curves) for reserves relative to the PSSAS design. If the PSSAS design is unlikely to be ready for implementation when the spot market design is ready, AEMO could (subject to relevant consultations and approvals) begin by implementing the ORDCs with the current out-of-market commitment design used to meet other ESS needs while the PSSAS design is developed for implementation.

9.21 Under this approach AEMO would develop the PSSAS design to use in two ways:

- First, the PSSAS design could be used as a transition mechanism while the designs of spot markets (and the underlying demand curve concepts) for inertia and system strength are examined for some NEM regions (e.g. South Australia and Victoria); and
- Second, the PSSAS design could be used as a long-run back-up to a market-based self-commitment design in some NEM regions (e.g. South Australia and Victoria) and as a back-up in other NEM regions as their reliability needs emerge (before spot markets in those regions, if appropriate, are implemented).

9.22 In Phase 2, the PSSAS design for additional commitments for system strength and inertia would be implemented across the NEM. In addition, there could be further progress on the development of spot markets (and the underlying demand curves) for inertia:

- In Phase 2A, the spot market for inertia could be developed and implemented in the region(s) where this is most urgent (this is likely to be South Australia); and
- In Phase 2B, the next step would be to implement spot markets for inertia in other regions as needed, drawing on lessons from the initial implementation in South Australia.

9.23 In Phase 3, the learnings from the spot markets for inertia would be applied to system strength. If feasible and appropriate, this phase could involve the implementation of spot market for system strength to support additional VRE output in the region(s) where most needed (e.g. South Australia). This approach would build on the TLA Tables, in which AEMO is able to describe how combinations of different resources can support higher penetration of renewables on the system. This progressive approach, where AEMO starts with a spot market for system strength to support VRE output in South Australia, seems to provide a useful first step in implementing markets for system strength that would inform the more complex step of implementing a demand curve for minimum system strength requirements.

9.24 The timing and the need for Phase 3 would be informed by the extent to which system strength limits VRE output after the Phase 1 and Phase 2 implementation. It is possible the implementation of spot markets for reserves and inertia could have the following impacts:

- Phase 1 and 2 could materially reduce the frequency of directions being issued to meet system strength needs. In this case it may not be appropriate to implement Phase 3 design that seeks to address constraints on VRE output, in which case Phase 3 may be delayed.
- Conversely, continuing changes in resource mix could increase the importance of implementing markets for system strength, in which case Phase 3 might need to be accelerated.

9.25 Throughout Phase 3, however, we consider that the PSSAS design could continue being used as back-up for system strength and for inertia.

9.26 Phase 4 would build further on the earlier phases by implementing a spot market for minimum system strength. In Phase 4A, this would be performed for region(s) where most relevant (e.g. in South Australia), while in Phase 4B, the spot market (and the underlying demand curve) for minimum system strength in other regions could be implemented if and when the needs for such an approach become frequent enough to warrant the implementation effort.

Conclusions

9.27 The choice between the three approaches described above (progressive, one-off or balanced) to adapting the ESS arrangements is more important in driving investment decisions than in driving operational decisions (as irreversible decisions may be made in particular assets that influence the long-term NEM market outcomes).

9.28 Overall, we consider that the third approach, i.e. the balanced approach may offer a compromise on the way forward. In this approach, a new market design for ESS is implemented with an embedded long-term vision of a VRE/IBR-dominated power market, but the details of the specific services continue to be developed over time, in line with the actual evolution of the market and technology. This approach recognises that:

- In the long run, there is likely to be a need to procure and schedule a variety of ESS that is wider than the current set of services (both in terms of types of services and/or their granularity).
- In the short run, software systems and market processes should be developed to accommodate future flexibility, recognising that market and system needs will continue to evolve in ways that cannot be accurately specified at this point in time. No-regret actions should be prioritised to minimise the risk that the reforms turn out to be either unnecessary, disproportionate or even detrimental. Moreover, the ESS could be set up in a flexible manner both in the market design and in the underlying software systems, so that changes in parameters can be readily made by AEMO, without the need for a major software project involving the vendor, when further changes to market design are implemented.

9.29 A pathway for the procurement and scheduling of ESS based on spot markets (Option 3 in Figure 7-1) can readily accommodate the balanced flexible implementation approach as parameters including penalty prices, procurement targets, and even the number of steps in the demand curve can be embodied in tables that can be modified as needed. The balanced approach would also accommodate the possibility of progressively (i) adding new services as needed (e.g. inertia, and system strength) and (ii) tweaking the parameters on the existing services as new information becomes available. Services can be introduced and/or amended based on their relative urgency and policy priorities.

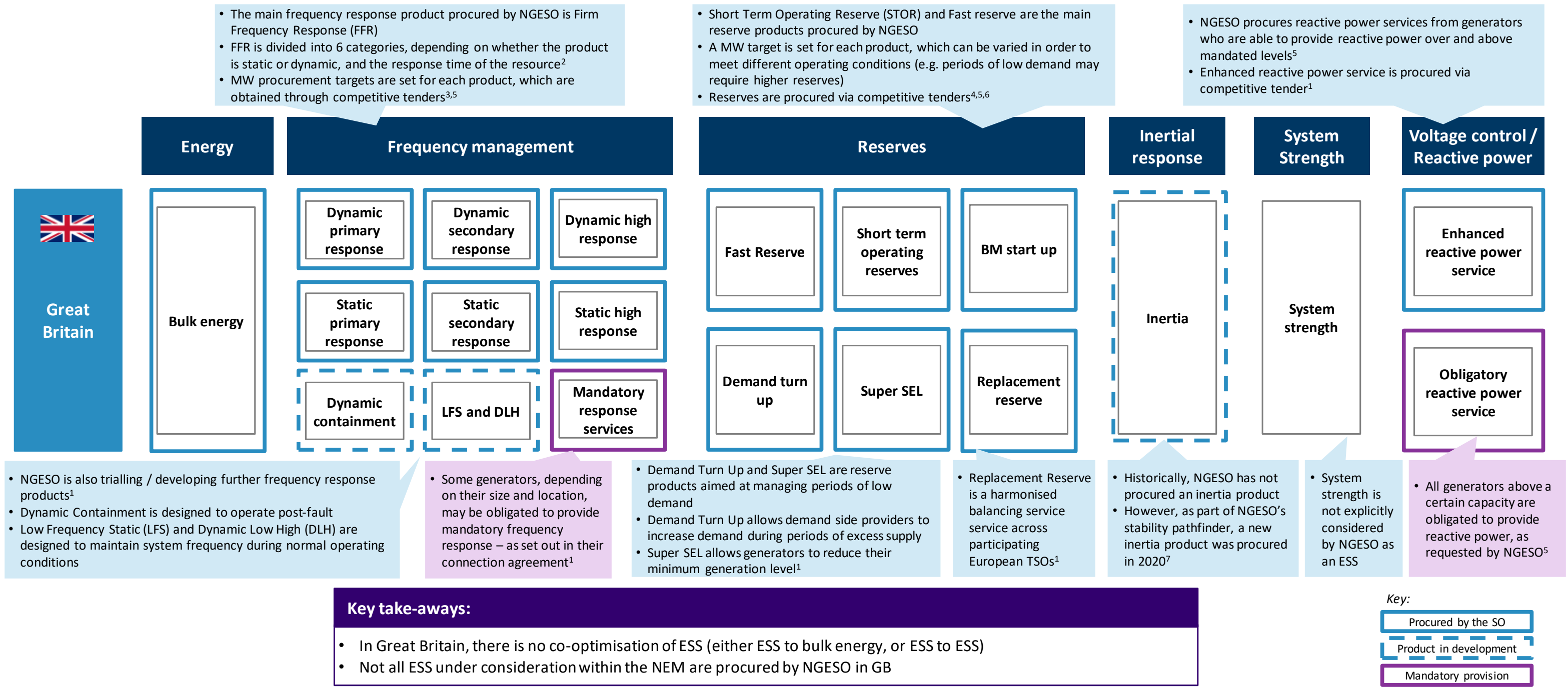
9.30 At the same time, the definition of the “demand curves” as described previously, allows the system to continue being operated in as conservative a manner as is required, with relaxations of the conservative rules only being performed as and when the SO (subject to appropriate external oversight) is comfortable to do so.

Appendix 1
International examples of ESS procurement frameworks

A1.1 This Appendix summarises the approach that GB and selected North American ISOs have taken to procuring ESS, focusing in particular on the degree of co-optimisation among different ESS.

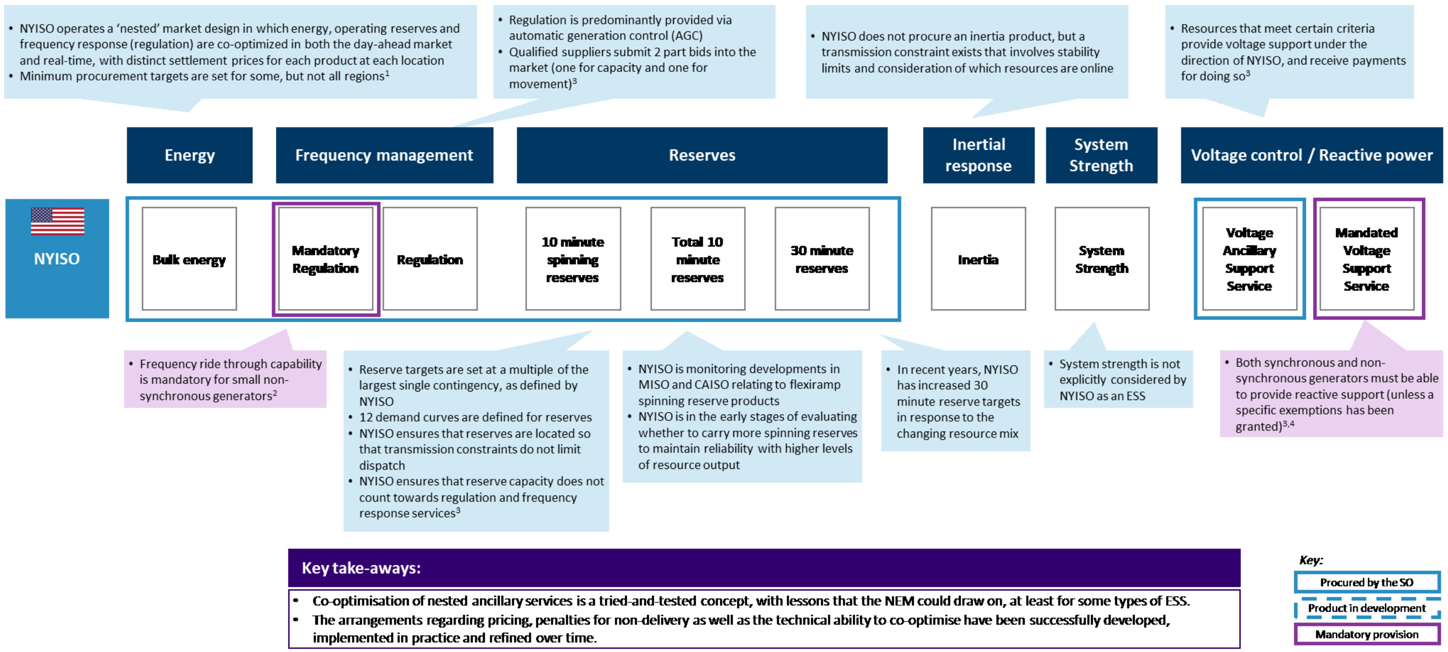
A1.2 The following pages present the case for NGESO in GB, followed by NYISO, MISO and Ontario IESO in the US.

Figure A1-1: Procurement of ESS by NGESO



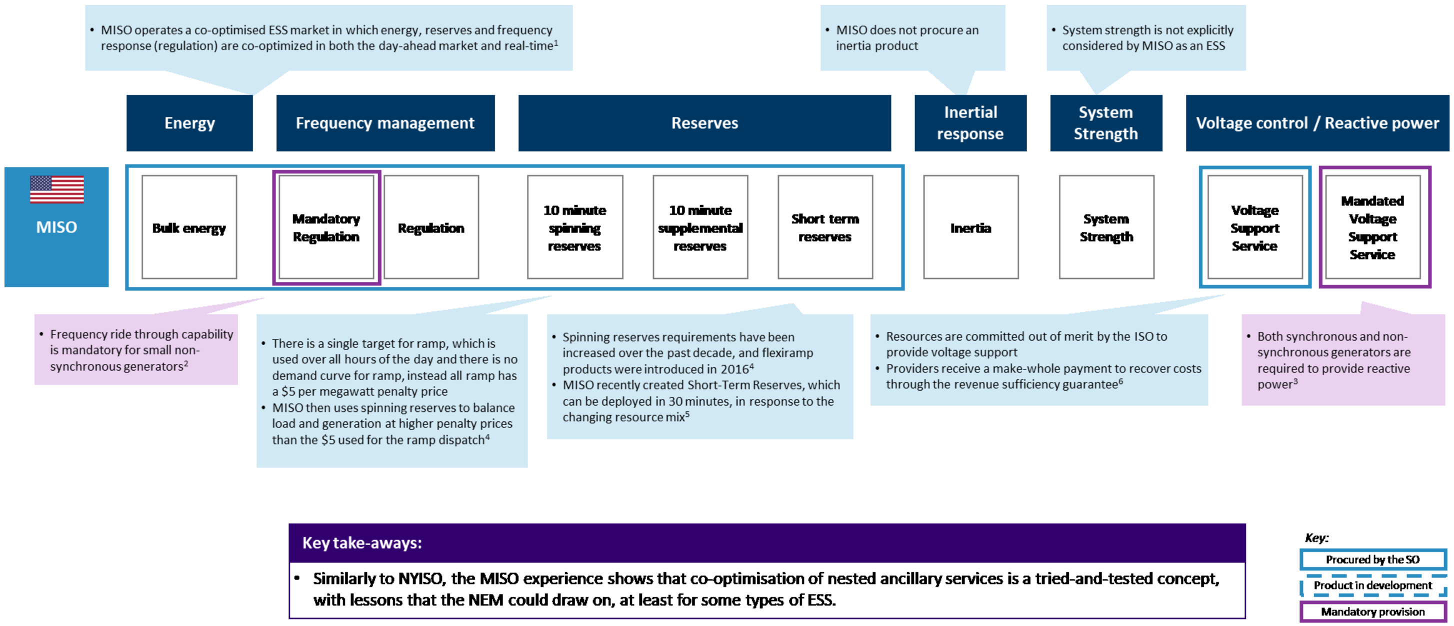
Source: 1) NGESO Balancing Services Website ([link]) 2) NGESO ,The Firm Frequency Response (FFR) Market ([link]) 3) NGESO, The Firm Frequency Response FFR Assessment Process ([link]) 4) NGESO, STOR Market Information Report ([link]) 5) NG ESO (2019) Procurement Guidelines ([link]) 6) NGESO, Fast Reserve Market Information Report February 2020 ([link]) 7) NGESO (2019) Stability Phase 1 Tender Information Pack ([link]).

Figure A1-2: Procurement of ESS by NYISO



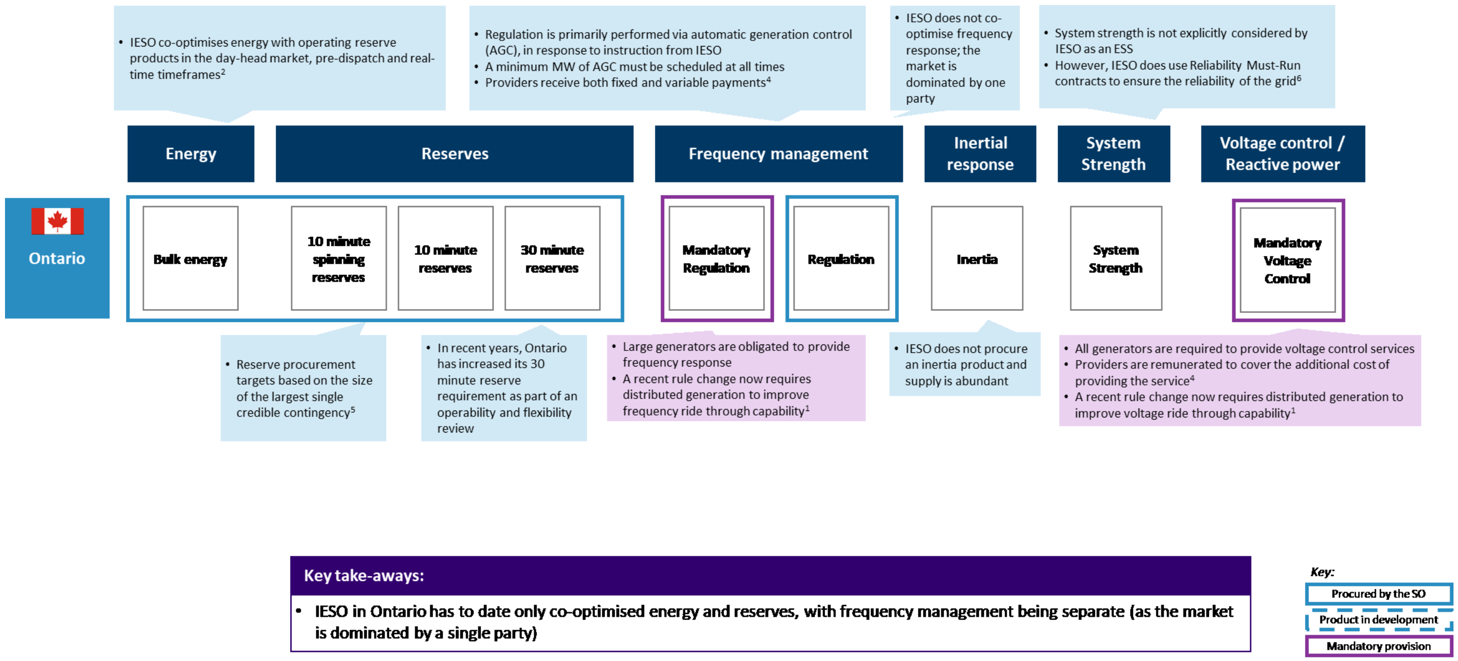
Source: 1) FTI International Experience Memo 2) FERC order No. 828, 2016 ([link]()) 3) NYISO Ancillary Services Manual, Issued May 2020 ([link]()) 4) FERC order No. 827 ([link]()).

Figure A1-3: Procurement of ESS by MISO



Source: 1) MISO State of the Market 2018 (link) 2) FERC order No. 828, 2016 (link) 3) FERC order No. 827 (link) 4) FTI International Experience Memo 5) FERC, ER20-42-000 (link) 6) MISO State of the Market 2018 Appendix (link).

Figure A1-4: Procurement of ESS by Ontario IESO



Source: 1) IESO, Market Renewal Program: Energy Overview, Nov 2019 (link) 2) IESO, Market Renewal Program: Energy Stream, OFFERS, BIDS AND DATA INPUTS Detailed Design, May 2020 (link) 3) Review of the ISO-Controlled Grid's Operability to 2025, June 2019 (link) 4) IESO Ancillary Services Market Website (link) 5) IESO Operating Reserve Market Website (link) 6) Market rules for the Ontario Electricity Market, Section 7 (link).

Appendix 2
International case studies of regulatory regimes for ESS

A2.1 In this appendix, we outline at a high level several aspects of the regulatory regimes that are used within GB and the US, and for each jurisdiction provide a number of examples that demonstrate the extent to which the SOs have the discretion to alter existing ESS markets and develop new ESS.

GB Experience – Regulatory Regime

Incentive-based system

A2.2 From 2011 to 2018, a performance-based regime was in place in GB, known as Balancing Services Incentive Scheme ("BSIS").

A2.3 Under the scheme, an annual target for NGESO spend was agreed each year, based on NGESO's modelling of both the historical relationship between volumes and costs, and balancing services constraint optimisation. Any underspend or overspend relative to this target was shared between NGESO and consumers, subject to a cap and collar on NGESO profit or loss. For the years 2015 to 2017, the sharing factor was set at 30% (meaning that NGESO would keep/incur 30% of any underspend/overspend), with the cap and collar set at ±£30 million.[257] In addition, NGESO was able to apply for an extra £10 million of funding as part of an innovation roll out scheme.[258]

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[257] Ofgem, Electricity System Operator Incentives from April 2017, 4 August 2016 (link), page 11.

[258] Ofgem, Electricity System Operator Incentives from April 2017, 4 August 2016 (link), page 24.

A2.4 The BSIS scheme was replaced in 2018 with a new scheme, in part due to challenges faced by the scheme. For example, there were concerns that the models underpinning the BSIS scheme were not performing as expected and that a mechanistic, rigid approach was not suitable for the rapid changes that were occurring in the electricity system.[259] Additionally, a review found that a number of errors existed in the models that were used to set the target.[260] The ownership and operation of the model by NGESO also raised issues of information asymmetry between the regulator and the NGESO, such as the potential for regulatory gaming.

A2.5 In the final year of the scheme, the sharing factor was reduced to 10%, with the cap and collar also reduced to ±£10 million, in order to protect consumers from potential impact of flaws in the BSIS.[261]

Ex-post evaluation system

A2.6 NGESO is now subject to an ex-post evaluation framework, which Ofgem describes as a "principles-based" approach.[262] Ofgem defines a set of principles and roles which NGESO must adhere to. Every year, NGESO is required to engage with stakeholders to develop a Forward Plan, which sets out how it intends to adhere to these principles and roles. Its annual performance is evaluated ex-post by an independent Performance Panel, producing a scorecard based on evidence provided by NGESO, Ofgem and other stakeholders.[263] This scorecard is used, alongside other evidence, to determine a financial reward or penalty worth up to ±£30 million. The penalty or reward is distributed through the same cost pass-through mechanism as NGESO's standard balancing market operation revenues.

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259 Ofgem, Final Proposals for the Electricity System Operator Incentives from April 2017, 1 March 2017 (link), page 5.

260 Ofgem, Final Proposals for the Electricity System Operator Incentives from April 2017, 1 March 2017 (link), page 7.

261 Ofgem, Final Proposals for the Electricity System Operator Incentives from April 2017, 1 March 2017 (link), page 8.

262 Ofgem, Policy decision on electricity system operator regulatory and incentives framework from April 2018, 23 February 2018 (link).

263 Ofgem, ESO performance panels end of year evaluation report 2018-19, 28 June 2019 (link), page 5.

Ofgem regulatory sandbox

A2.7 In February 2017, Ofgem launched a regulatory sandbox service that was designed to enable innovators (i.e. start-ups, corporations, councils and not-for-profits) to trial new products, services and business models that could benefit consumers without some of the normal regulatory barriers applying.[264] While this model is not specific to system services, it provides some general lessons for testing new market design features.

A2.8 Trials running within the regulatory sandbox last for a set period of time with a limited number of customers. Each trial is expected to have specific learning objectives to assess the long-term viability of the model being tested. Following the completion of the trial, the trial promoter must report what it has learnt to Ofgem for the latter to use in future policy development.

A2.9 In order to be eligible, the trial must meet the following criteria:[265]

- **The proposal is genuinely innovative**: the product or service is not already offered, or the business model is sufficiently different from existing alternatives.
- **Innovation will deliver consumer benefits and consumers will be protected during the trial**: the potential for consumer benefit must be demonstrated directly or indirectly, and possible consumer risks and how to mitigate them must be considered.
- **A regulatory barrier inhibits innovation**: Ofgem will remove barriers to the extent that they are within its regulatory jurisdiction and assist in bridging the gap with other relevant bodies.
- **The proposal can be trialled**: the project's promoter has a well-developed plan with clear objectives. Success criteria must be completed within 24 months of the sandbox being granted.

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264 Ofgem, Innovation Sandbox Service Overview, 27 February 2020 (link).

265 Ofgem, What is a regulatory sandbox?, September 2018 (link).

A2.10 Initially, applications for a regulatory sandbox had to be made during "windows". However, following two windows, the process was adapted so that applications could be received at any time. This change was made following feedback that an "on-demand" service (where applications could be made at any time) is better for project proponents, as the stage of an idea's development is likely to determine the timing of requests.[266] This is just one example of how Ofgem has evolved the regulatory sandbox overtime in response to feedback from stakeholders and learnings from initial trials.

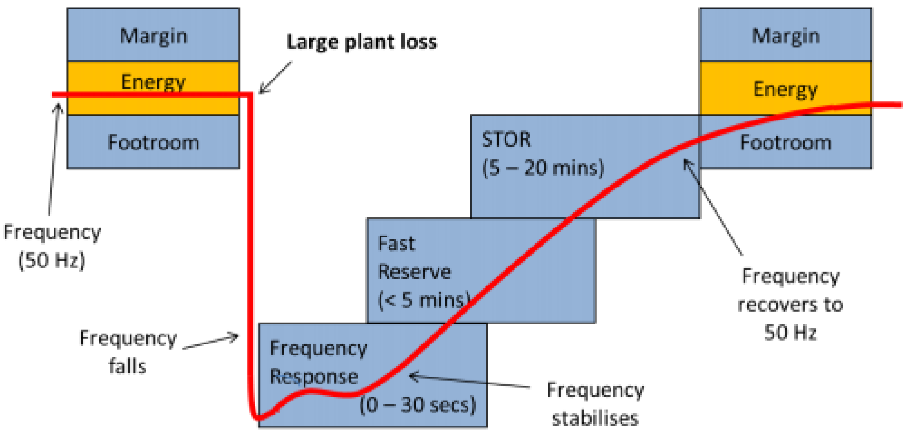
GB Experience – Examples of SO Discretion

A2.11 This section presents three specific examples where NGESO in GB has been able to take initiative in developing or enhancing system services (Enhanced Frequency Response, Short Term Operating Reserve and Pathfinder projects). This illustrates how SOs may be able to exercise flexibility and discretion, within prescribed limits.

A2.12 In GB, NGESO uses a combination of frequency response and reserves to return the electricity system to normal following an unexpected system outage (i.e. unexpected loss of a large generating unit). Frequency response is deployed within seconds to stabilise frequency. Fast reserve generating units are then deployed within minutes to add generation to the system, which begins to restore system frequency. Finally, STOR are deployed within a period of five to 20 minutes to continue the restoration of frequency to normal levels. This three-pronged approach is outlined in the figure below.

266 Ofgem, Innovation Sandbox Service Overview, 27 February 2020 (link).

Figure A2-1: National Grid ESO response to a major outage in GB



Source: National Audit Office, Electricity Balancing Services, May 2014 (link).

A2.13 The following two subsections discuss the reserves and frequency response services in more detail, before turning to the most recent Pathfinder services.

Short Term Operating Reserves

A2.14 The procurement of STOR has evolved over time at NGESO's discretion since its introduction in 2007. Initially, tenders were for contracts up to two years ahead.[267] Not long after the initial tender, NGESO introduced long-term STOR contracts (up to 10 years) in order to incentivise potential investors to participate. It was thought that long-term contracts would allow potential providers the ability to tender to receive a long-term revenue stream "*where significant investment is required to offer a service, to more efficiently recover capital expenditure*".[268]

A2.15 NGESO have since discontinued these long-term contracts in of favour of short-term STOR contracts that can last up to two years.[269]

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267 National Grid, Demand Side Opportunities, 25 Jan 2007 (link), page 10.

268 National Grid SO, Incentives for 1 April 2010, Initial Proposals Consultation, 5 November 2009 (link), page 85.

269 National Grid, Short Term Operating Reserve (STOR), Interactive Guidance, January 2018 (link), page 11.

Enhanced Frequency Response

A2.16 In 2016, NGESO trialled a service called Enhanced Frequency Response ("**EFR**"),[270] an auction-style procurement, which was predominantly targeted at battery developers who would be able to provide frequency response in one second or less.[271] This service was highly attractive to prospective storage developers and was therefore heavily oversubscribed. However, it is somewhat unclear whether the clearing price of the auction reflected actual economic drivers, or the "fear of missing out".

A2.17 At the time of the initial tender, EFR was expected to be an "enduring service", aimed at mitigating the effects of falling system inertia on frequency control. Annual tenders were expected to be run for long-term fixed EFR contracts and monthly tenders for short term flexible EFR contracts.[272] However, NGESO decided to discontinue the procurement of EFR in 2017 after only one tender and replace it with a more integrated suite of frequency response products that would better meet NGESO's requirements.[273]

A2.18 NGESO had significant flexibility in how it ran the first EFR procurement process. Rather than procure a set quantity of EFR, NGESO could choose how much to procure based on how "economic" bids were.[274] This process is therefore akin to a "demand curve" in the sense that the quantum procured is dependent on the price (rather than fixed). The bids were also assessed against the existing frequency control services – although NGESO's procurement of such services was unaffected by the introduction of EFR.[275]

270 Frequency response is procured to maintain frequency within a defined Hz band around 50Hz. A faster response enables the system operator to arrest any frequency deviation more quickly, before the frequency deviation deteriorates further away from 50 Hz.

271 National Grid, Enhanced Frequency Response, FAQ, 29 March 2016 (link).

272 National Grid, Enhanced Frequency Response, FAQ, 29 March 2016 (link).

273 National Grid, Flexibility Workstream Update: Rationalisation of Products and Short Term Actions in the Firm Frequency Response Market, 30 October 2017 (link).

274 National Grid, Enhanced Frequency Response, FAQ, 29 March 2016 (link).

275 Source: National Grid, Enhanced Frequency Response, FAQ, 29 March 2016 (link).

A2.19 Furthermore, it was NGESO's expectation that the technical requirements and rules of EFR procurement would adapt over time in response to changing system needs and learnings from the procurement process itself. For example, the tender value was capped at 50MW (minimum 1 MW) per applicant for the first tender round. This rule was designed to remove any Grid Code concerns and to provide NGESO with the opportunity to develop a pool of providers with different technologies and response characteristics, hence reducing the risk when procuring a new service. However, this cap was expected to increase or be removed in subsequent tender rounds once the risks were better known, to potentially capture economies of scale from larger scale procurement.[276]

Pathfinder projects

A2.20 In 2017, Ofgem, the GB energy market regulator, announced its intention to legally separate NGESO from the transmission operator and wider National Grid group.[277] To accompany this change, Ofgem developed a new regulatory and incentives framework for the system operator to operate under, which became effective in 2018.[278] Under this framework, NGESO is strongly incentivised to introduce competitive processes where possible and to drive innovation "*across the asset development and operations process*". Additionally, under the terms of its licence, NGESO is obligated to "*identify long-term electricity system needs [and] develop and assess options to meet these needs*".[279]

276 National Grid, Enhanced Frequency Response, FAQ, 29 March 2016 (link).

277 Ofgem, Greater separation for National Grid's system operator role, 12 January 2017 (link).

278 Ofgem, ESO Roles and Principles, 23 February 2018, (link).

279 Ofgem, ESO Roles and Principles, 23 February 2018, (link) page 17.

A2.21 In response to the new framework, NGESO set out a Network Development Roadmap in May 2018, which outlined plans for a series of "pathfinding" projects.[280] NGESO stated that the pathfinding projects would allow it to *"explore, experiment, and learn"* and to refine its frameworks for addressing system needs.[281] Each pathfinding project aims to address a specific system need through the creation of a new commercial product, which NGESO procures via a competitive tender. The projects are undertaken on a small scale, with the existing market mechanisms and procurement channels continuing to operate, minimising the risk to the wider system associated with trialling innovative products. There are currently three pathfinder projects underway, which focus on system stability, high voltage and transmission constraint management.

A2.22 The **system stability pathfinder project** aims to develop a commercial product to promote system stability and mitigate the risks associated with forecasted declines in synchronous generation.[282] NGESO specified that bidders must be able to provide inertia, fast active dynamic voltage support, and increase the short circuit level (the latter being one of the proxies for system strength in the NEM).[283] Phase one of the project, which is primarily focused on the provision of inertia, was open to synchronous condensers and synchronous generators running in synchronous condenser mode. In January 2019, NGESO announced that it had agreed contracts with 5 parties through the phase one tender to provide the service.[284] In June 2020, NGESO published the Request for Information ("**RFI**") for phase two, which is focused on the short circuit level and is open to a wider range of technologies than phase one.[285]

280 National Grid, Network Development Roadmap Consultation, May 2018 (link).

281 National Grid ESO, Network Options Assessment 2018/19, January 2019 (link), page 15.

282 NGESO, Stability Pathfinder RFI, 19 July 2019 (link), page 7.

283 NGESO, Stability Pathfinder Phase One Outline Plan, 21 October 2019 (link), page 6.

284 NGESO, National Grid outline new approach to stability services announcement, 29 January 2020 (link).

285 NGESO, Stability Pathfinder Phase 2 RFI, 17 June 2020 (link), page 7.

A2.23 The **high voltage pathfinder project** aims to introduce a commercial product to mitigate increasing voltage levels in the Mersey area of GB, which are being driven by decreasing minimum transmission demand and decreasing reactive power consumption.[286] NGESO is also aiming to develop alternatives to the traditional services provided by large generators and the transmission operator. The project is open to any provider and technology (providing it can meet certain technical requirements, including a minimum reactive power absorption level). In May 2020, NGESO announced that it had awarded 9-year contracts to two commercial providers (one equipment and one battery), at a cost of £8.67 million.[287]

A2.24 The **transmission constraint pathfinder project** aims to create a new commercial project to manage network constraints, which are projected to worsen in future years.[288] The initial stages of the project are intended to focus on alleviating constraints between the north and the south of GB (the B6 boundary, i.e. between England with high level of demand but limited generation and Scotland with significant levels of wind generation but relatively low levels of demand). NGESO propose either a single location solution, where a single asset is placed on the exporting side of the constant, or a duel location solution, with an asset on either side of the constraint. An upcoming tender will aim to procure a 200MW, 2-hour service.

US Experience – Regulatory Regime

A2.25 This subsection describes some of the key features of the regulatory regime in the US and sets out that, in general US ISOs have been constrained in their ability to flexibly adapt to the evolving system needs. However, there are several examples of situations where US ISOs have been able to exercise more discretion. This experience could provide helpful learnings to the NEM in the context of developing a new regime that provides an reasonable balance between rules and flexibility applied to the system operator.

286 NGESO, NGESO (2019) Mersey Long Term Reactive Power Services RFI Webinar, 1 May 2019 (link).

287 NGESO, A new approach to managing voltage and reactive power, 21 May 2020 (link).

288 NGESO, Constraint Management Pathfinder RFI, December 2019 (link).

A2.26 One of key characteristic of the US ISOs is that they are largely non-profit organisations and typically have management incentives for achieving targets set by the independent board. In practice, setting good incentives for US ISOs has proven to be very challenging:

- First, the management incentives typically lead to incentive thresholds being set low and are seen as being too narrow.
- Second, the targets are set ex-ante, and achieving them may not necessarily be the optimal outcome on an ex-post basis. In other words, sometimes not achieving a target and instead shifting system operator resources to address other more urgent priorities reflects better management performance as the situation evolves over the year.

A2.27 As a result of the difficulties in designing good incentives for the US ISOs, in general, they are not able to establish and procure new system products and services without prior regulatory approval from the relevant body (Public Utility Commission ("**PUC**") for ERCOT, FERC for other ISOs). The Ontario IESO also faces similar restrictions.

A2.28 When proposing changes to system products and services, North American ISOs typically have governance processes which require market participants to vote on proposed changes. The ISOs may face less scrutiny for proposals that have received the broad support in the voting process (typically well above 50%).[289]

A2.29 ISOs can file for changes at FERC even when opposed by stakeholders, but there is a much higher threshold for approval. ISOs can also test new services, but generally must obtain at least some degree of stakeholder approval. Additionally, anything involving rates must as a matter of law be approved by FERC (unless it is an adjustment based on a FERC approved formula rate).

[289] NYISO and PJM are among the ISOs with this type of process involving explicit stakeholder votes. Conversely, CAISO files changes with the regulator without a prior explicit stakeholder vote. A potential issue with this approach is that without explicit "on the record" prior approval, reaching a compromise during the FERC process may be more challenging as parties may renege on informal agreements.

A2.30 In practice, this means that the ease and speed with which new services can be approved is dependent on the levels of support for and/or opposition to the proposal:

- If there is widespread support for a proposed change from stakeholders, a change can be approved and go into effect relatively rapidly.
- However, if a proposal is controversial and does not enjoy widespread support, it may take several years to receive approval from the regulator (or may not be approved).

A2.31 In the following section we show that the US regulatory framework provides several designs that regulators and stakeholders can utilise to allow the SOs to exercise discretion, within specific limits or in response to particular conditions.

US Experience – Examples of SO Discretion

A2.32 The following subsections set out three case studies that illustrate specific circumstances in which US ISOs are able to exercise a degree of discretion. We present one case study from MISO, two from NYISO and one from CAISO.

MISO – Short-Term Reserves

A2.33 In October 2019, MISO filed a proposed revision to its Open Access Transmission, Energy and Operating Reserve Markets Tariff that would create a new 30 minute Short-Term Reserve product.[290] The product would be procured through market mechanisms, with requirements determined dynamically based on transmission constraints. This would replace the current practice of committing out-of-market units, which MISO argued was inefficient and costly. The proposal faced a number of protests from stakeholders, including those who argued that the proposal would increase costs while providing little benefit, and that MISO had not demonstrated that costs would be assigned to beneficiaries (as required by cost causation principles). However, on 31 January 2020, FERC concluded that MISO's proposal was "*just and reasonable*"[291] and therefore accepted the proposal, which is to become effective from December 2021.

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290 FERC, Docket No. ER20-42-000, 31 January 2020, (link).

291 FERC, Docket No. ER20-42-000, 31 January 2020, (link), page 13.

NYISO – Interchange Pricing Extraordinary Corrective Action

A2.34 In September 2000, NYISO modified its interchange pricing rule in order to correct problems relating to interchange pricing and scheduling. NYISO was able to implement this change through its Extraordinary Corrective Action ("**ECA**") mechanism. This mechanism gave NYISO significant discretion to make unilateral changes for a period following significant changes to the market. Specifically, the ECA mechanism sat within a range of Temporary Extraordinary Procedures that were afforded to NYISO by FERC to "*address market design flaws, transitional abnormalities and severe operational difficulties"* that might surface after the markets became operational.[292]

NYISO – Collateral Policy for Financial Transmission Rights

A2.35 Until 2017, all elements of NYISO's collateral requirements for financial transmission rights were included in NYISO's tariff and therefore required both a stakeholder process and federal regulatory approval to implement any changes in the formulas. NYISO implemented both an expanded framework for auctioning financial transmission rights and an enhanced collateral design that used the valuation from the additional auctions to implement and enhanced mark-to-market collateral design.

A2.36 While outcomes in another US electricity market with similar auctions were used to calibrate key parameters in the new design, it was recognised by the SO and stakeholders that this calibration was necessarily imperfect. Hence, market participants and the federal regulator did not require NYISO to include the key parameters in its tariff but instead required that they be posted on the NYISO website and agreed that any changes would be subject to approval by the NYISO Management Committee.[293]

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292 United States Court of Appeals, Case #06-1027 Document #1086980, 18 December 2007 (link), page 4.

293 The NYISO Management Committee is an element of the NYISO governance structure. Since only NYISO market participants have voting rights in the NYISO management committee, the requirement for management committee approval prevented NYISO from implementing any changes that were not approved by market participants. However, this provision allowed such changes to be implemented much more quickly than if approval by the Federal Regulator was required before changes in collateral policy could be implemented. Source: NYISO, Re: Proposed Tariff Revisions to Implement Balance-of-Period TCC Auctions and Enhancements to the Credit Requirements for TCCs FERC Docket ER17-1167-000, 13 March 2017 (link), page 15.

A2.37 The rationale for this design was to allow NYISO to quickly make adjustments to these collateral requirements if it became apparent that the rules were not performing as intended. This discretion would also enable NYISO to quickly make changes in these parameters if market conditions changed in a way that materially impacted the variability of forward prices.

A2.38 In approving this NYISO discretion, market participants recognised that NYISO could be less conservative in setting collateral margins if it can change them quickly if they were too low.

CAISO – New Generator Connection Amendment

A2.39 In 1999, CAISO proposed an amendment to its pricing tariff in order to avoid additional constrained down payments under its zonal pricing design. This amendment would have established new cost responsibility rules for the connection of new generation.[294] Specifically, the amendment would have required new generators to bear the increased congestion mitigation costs associated with its connection, but only in areas where the generation market was not competitive. Mitigation options would have included reducing the generator's own generation, paying other generators to redispatch, paying for system expansion, or paying CAISO for congestion management.

A2.40 The amendment was opposed by some stakeholders in the approval process at FERC, with stakeholders arguing that the proposal would have treated new and existing generators unequally. FERC rejected the proposal because it deemed that the proposed change would result in customers facing incorrect, inflated prices for mitigating increased congestion and therefore the proposal was never implemented.

A2.41 This outcome turned out to be fortunate as a year later the system was short on capacity (due to a lower hydro generation), meaning the extra capacity that may have been reduced by the amendment was needed to meet demand.

[294] FERC, Docket No. ER99-3339-001, January 31 2000 (link).

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BSIS	Balancing Services Incentive Scheme
CAISO	California Independent System Operator
CFD	Contract for difference
COAG	Council of Australian Governments
DRSP	Demand response service provider
DER	Distributed Energy Resource
East	East of Central-East NYISO region
ECA	Extraordinary Corrective Action
EFCS	Emergency Frequency Control Scheme
EFR	Enhanced Frequency Response
ERCOT	Electric Reliability Council of Texas
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
ESS	Essential System Services
FCAS	Frequency Control Ancillary Services
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
FUM	Forecast uncertainty measure
GWs	Gigawatt-second
IBR	Inverter-based resources
IMM	NYISO’s Independent Market Monitor
ISP	Integrated System Plan
ISO	Independent System Operator
ISO NE	ISO New England
KPI	Key performance indicator
LI	Long Island NYISO region
LMP	Locational Marginal Pricing
LOR	Lack of Reserve
MASS	Market Ancillary Service Specification
MISO	Midcontinent Independent System Operator

MPFR	Mandatory Primary Frequency Response
MWs	Megawatt-second
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NERC	North American Electric Reliability Corporation
NGESO	National Grid Electricity System Operator
NIC	Network Innovation Competition
NSCAS	Network Support and Control Ancillary Services
NSP	Network System Provider
NYC	New York City NYISO region
NYCA	New York Control Area NYISO region
NYISO	New York Independent System Operator
OFTO	Offshore Transmission Operator
ORDC	Operating Reserve Demand Curve
PASA	Projected Assessment of System Adequacy
POE	Probability of Exceedance
PSSAS	Power System Security Ancillary Services Market
PUC	Public Utility Commission (Texas)
RAM	Resource Adequacy Mechanism
RERT	Reliability and Emergency Reserve Trader
RFI	Request for Information
RoCoF	Rate of Change of Frequency
RRAS	Ramp Rate Ancillary Services
RRP	Regional Reference Price
RT	Real time
SENY	Southeastern New York NYISO region
SO	System Operator
SQSS	Security and Quality of Supply Standard
SRAS	System restart ancillary services
STOR	Short-Term Operating Reserve
TLA Paper	AEMO, Transfer Limit Advice – System Strength, February 2020 (link)
TNSP	Transmission Network System Provider
VOLL	Value of lost load
VRE	Variable renewable energy