ENERGY SECURITY BOARD

Post 2025 Market Design Options – A paper for consultation

Part B

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1. Resource Adequacy Mechanisms

1.1. Generator exit mechanisms

Orderly exit, within the context of the objective of timely entry and orderly exit for resource adequacy mechanisms, means:

- The reliability and security of supply continues to meet community expectations;
- Price shocks are minimised; and
- The exit of thermal generators is anticipated.

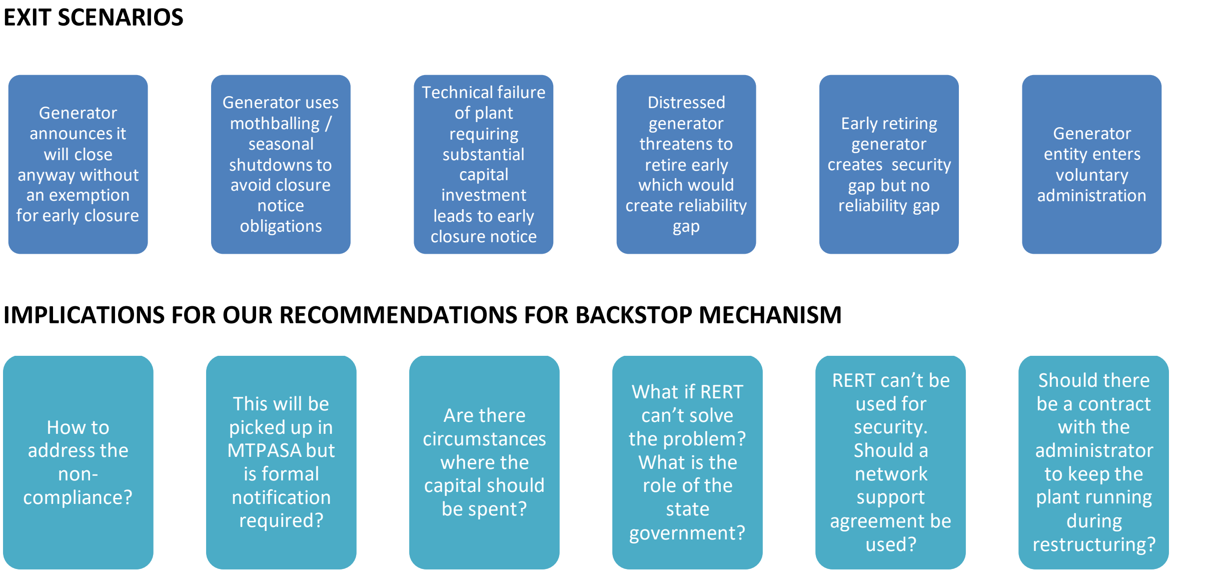
The balance of the proposed reform pathway is intended to create the right incentives on the owners of thermal generators to retire their assets in an orderly way. However, there remains a residual risk that if this does not occur, the counterfactual would threaten power system reliability, security and affordability for consumers.

Acknowledging this, and as flagged in the January 2021 Directions Paper, the ESB is considering how exit mechanisms may best address these risks. Building on the January Directions paper, there are three proposed exit mechanisms outlined below which are considered to be prudent backstops to addressing the residual risks identified above.

Scenario analysis

To understand the potential implications resulting from early generator exit and to assist in developing options, the ESB considered a range of potential exit scenarios as shown Figure 1.

Figure 1 Exit Scenarios and implications



The scenarios identified above, and their associated implications are not intended to be an exhaustive list of possible future outcomes. For example, additional scenarios could include future changes in legislation to pursue climate change targets, and sharp and unexpected changes in input costs (e.g., coal or gas prices). Similarly, additional implications could include rapid and unexpected changes in price signals in the spot and forward markets, changes in the role of existing state-based schemes targeting resource adequacy and the associated emissions, economic and/or employment impacts.

The implications from these scenarios could be amplified if multiple retirements of thermal generators happened at the same time.

The scenarios should instead be considered in light of their implications on the design of any future orderly exit mechanism. For instance, the scenario where a generator chooses to mothball for many years leads to consideration as to whether mothballing should be scoped into a notice of closure obligation. This in turn raises the question of how mothballing could be identified within the existing information provisions within the NEM and whether any changes are required.

Option 1: Increased information around mothballing and seasonal shutdowns

Any action to manage the orderly exit of a large, retiring thermal generator requires that accurate information is made available to the key stakeholders in a timely manner.

It is anticipated that the growth of renewables will continue to impact the operations of legacy thermal generation throughout the NEM. Already it is apparent that coal fired generation is operating with greater flexibility so that it can respond to negative prices during the middle of the day by reducing output at these times before ramping up to full load for the evening peak.

Over time the ESB expects that the energy transition will drive further changes to operating regimes whereby owners seek to reduce their overheads if low wholesale prices are expected. This could include mothballing of units for prolonged periods of time and/or seasonal shutdowns or cyclical operating regimes e.g., weekday/weekend, day/night. The ESB acknowledge that maintaining a participants' flexibility to make such changes remains a key factor in the design of any future orderly exit mechanism.

The National Electricity Rules (NER) requires that generators provide AEMO with information on their expected operations via two key processes. These are the Medium-Term Projected Assessment of System Adequacy (MTPASA) process and AEMO's Generator Information Surveys that are an input into the Electricity Statement of Opportunities (ESOO) and include the generator's expected closure date. In addition, a generator owner may have financial market disclosure obligations where there are material changes to its operations.[1]

These existing information processes may not be fit for purpose for the future, given they were created without managing exits in mind. For instance, the MTPASA was originally focused on outage planning and while it will certainly capture a mothballing or seasonal shutdown it does not provide information about the reason for a unit's unavailability and does not indicate how long it would need to return to service beyond the current 24-hour notice window. Similarly, Generator Information Surveys typically request participants to nominate their available capacities over three time periods: Peak Summer, Summer and Winter. This may not be granular enough to cover new types of operating regimes moving forward.[2]

1 It should also be noted that financial market disclosure requirements will differ amongst participants subject to their ownership model and the materiality of a generator's operating regime on their business. What this means is that there is no consistent or specific obligation to report that a unit has been mothballed or is in a seasonal shutdown and the level of recall available (e.g., 1 week, 1 month) may not be clear.

2 MT PASA uses PASA availabilities of generating units. PASA availability includes the generating capacity in service as well as the generating capacity that can be delivered with 24 hours' notice.

Given the potentially opaque obligations surrounding the mothballing or seasonal shutdown of a generating unit(s), the ESB considers information provision from generators could be amended to:

- Extend the obligations upon generators when submitting their PASA availabilities to provide greater transparency as to their potential availability. This could include:
  - Adding a reason code to MTPASA indicating the type of outage from a selected list of outage types.
  - Creating a second or even third version of MTPASA with availabilities defined over different return to service durations (e.g., 7 days, 1 month).
- Amend information provision requirements for the Generator Information Survey process to require further information be provided about ongoing operational changes to generator availability such as seasonal or cyclical (weekday/weekend, day/night) shutdowns. For example: A Generator Information Survey could require a designated generator provide further granularity in relation to their likely operations over the forthcoming year (e.g., monthly available capacities as opposed to the current three periods).

Option 2: Expanding the notice of closure requirements to include mothballing

The ESB considers there could be merit in broadening the AER's generator notice of closure exemption requirements to include mothballing such that any significant early withdrawal of capacity from the market within the next 3½ years would require an exemption.

The guidelines (see Box 1) provide that, under certain circumstances, the AER can grant an exemption to the 42 months' advance notice period that generators must provide if they intend to close. In making its decision the AER has regard to, among other things, reliability and security impacts and seek to consult with AEMO and specific relevant stakeholders.

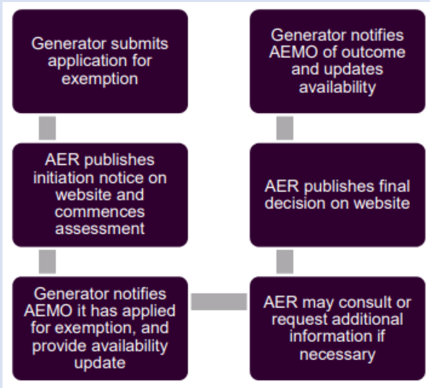
Box 1 AER Generator Notice of Closure Exemption Guidelines

From 1 September 2019, all generators are required to provide at least 42 months' advance notice of their intention to close, unless granted an exemption by the AER. Figure 2 highlights the standard application process for seeking an exemption from the AER. As part of the AER's assessment an applicant is compelled to provide a range of supporting information that could provide insight into the reasons behind the decision to close a nominated generating unit(s) and thereby seek exemption including:

- The date the generator made the formal decision to proceed with the nominated closure date,
- Key analysis, evidence or supporting information such as technical condition reports, or papers submitted to decision-making committees,
- Relevant dates and records of considerations surrounding the formal decision, and
- Other important supporting information the generator feels relevant.

In considering an application the AER will consult with relevant stakeholders including any affiliated auditors or consultants used by the generator, network service providers, the jurisdictional government, AEMO and/or other regulatory authorities as relevant. The AER endeavour to complete their assessment and consultation within 60 business days.

Figure 2. Exemption application standard process



Source: AER Generator Notice of Closure Exemption Guidelines. September 2019. Available here.

While the AER's process focuses on a participant's decision to close, there is no explicit compulsion upon a participant to advise what they would need to do to continue operating until the original closure date. Similarly, it is not clear what would happen if an exemption was not granted by the AER and a generator chose to close anyway or where a generator chose to not to seek exemption in the first place. This will of course have compliance implications.

There is a possibility that some retiring generators may, for legitimate reasons, permanently mothball a generating unit without going through the process of seeking an exemption from the AER for early closure.

Clearly, there is a spectrum of different mothballing arrangements from permanently unavailable all the way through to potentially being available within a short period of time if prices rebound. As a result, coming up with a definition of mothballing is not a straight-forward task. One possible approach could include reviewing the level of plant availability indicated in MTPASA and comparing to a threshold e.g., if the availability over the next three years was less than 10% the plant could be designated as mothballed.

Option 3: An integrated process to manage early exit

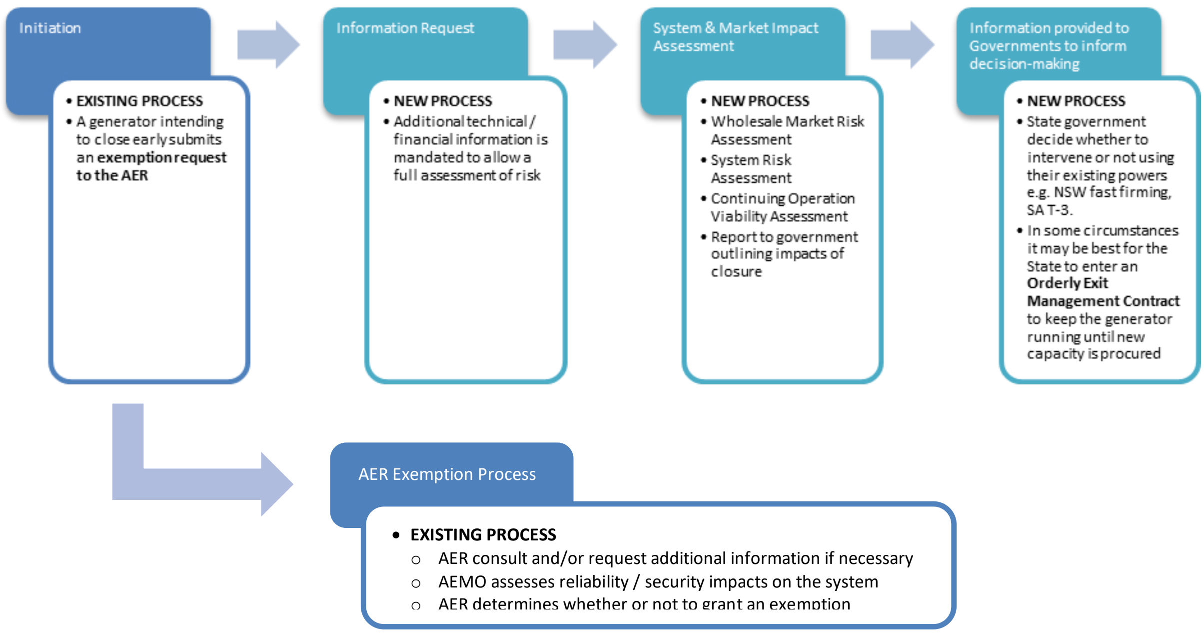
Under the current AER Generator Notice of Closure Exemption Guidelines the onus is on the retiring generator to provide the pertinent information. The AER will then consult with relevant stakeholders, including AEMO and governments, so that it can determine within 60 business days whether to grant an exemption or not. However, at the end of the process it is not clear what would happen to the power system if the AER refuses an exemption and the generator decides to close anyway.

History tells us that the early closure of a large, thermal generation is likely to attract significant attention from government and other stakeholders concerned at the potential risks to reliability, security and wholesale prices. They will be seeking early information from the retiring generator, AEMO and other parties (which may or may not have also been provided to the AER) so they can come to a view as to whether they need to take any action.

To improve the assessment process and to provide government and market bodies with a holistic understanding of the potential risks associated with early exit of a generating unit the ESB has developed an integrated process building upon the AER's exemption process.

This process, as shown Figure 3, would seek to replace an ad-hoc response with an integrated risk assessment that is understood by retiring generators, governments and industry. The purpose of the process is to gather information as early as possible so that a timely risk assessment can be conducted that allows a state government to act if they consider the risks are too great.

Figure 3. Integrated process for managing early closure



The integrated process builds on the AER's own exemption process by using an exemption request as the trigger. However, instead of leaving it to the retiring generator to decide what information is relevant the process would specify the information that the generator is required to provide. This could include a range of additional information (e.g., technical and/or financial) to allow a full assessment of the potential risks. The AER would focus on the information that they require to make their exemption decision whilst the additional information would be collated to allow a complete System and Market Impact Assessment. This would include the following individual assessments:

- System Risk Assessment:
  - What are the operational risks and challenges to reliability that cannot be addressed by existing RERT and RRO mechanisms?
  - What are the operational risks and challenges to security that cannot be addressed by existing mechanisms e.g., directions or Network Support Agreements?
- Wholesale Market Risk Assessment:
  - What are the implications for wholesale prices?
- Continuing Operation Assessment:
  - Is there a reasonable prospect that the station could be operated safely, reliably and commercially for a period beyond the early closure date?

The ESB considers there to be merit in requiring only certain designated coal and gas fired generators in the NEM to go through this process. A designated generator may be defined as being of sufficient size that an early exit may have an adverse impact upon system reliability and security or wholesale energy prices. This approach is therefore deliberately targeted at those early retiring generators that could have a significant impact on the power system.

In designing this integrated process, the ESB recognises that state governments are best placed to deal with the risks of early closure, and that such an integrated process would dovetail with the suggested contingency planning for sudden exits suggested in the January 2021 Directions paper. State governments may already have their own state schemes, RRO trigger rights or government owned enterprises that can be brought to bear to address issues arising from early closure. They are also best placed to make the trade-off between the risks that they are seeking to mitigate and the costs of intervention – acknowledging that although an early closure is not an optimal outcome as considered by the notice of closure framework, allowing an early exit as notified, may practically remain an optimal and prudent outcome for all stakeholders.

Further, any System and Market Impact assessment may be utilised by state governments and market bodies in completing a full assessment of all potential alternative options to address these risks prior to making a decision to intervene or not. The integrated process also considers that any scenario that leads to an early exit decision is likely to be unique and will require a specific solution.

One last-resort outcome envisaged by the ESB is that the government may seek to enter into an Orderly Exit Management Contract (OEMC) with the retiring generator to keep it running until the risks of exit reduce to an acceptable level. An OEMC would be similar to the Reliability Must Run (RMR) contract discussed in the January Directions Paper but would be entered into by the state government and a participant as opposed to an independent system operator and participant.

While the ESB has not attempted to identify a recommended OEMC structure there are key contract terms and provisions that would need to be addressed as part of any negotiation including:

- Obligations on generators to:
  - bid into the market and make the specified capacity / services available at the required times; and
  - ensure sufficient fuel supply was available and maintenance undertaken to meet output requirements until the end of the agreed term.
- Payment structures for performing the required obligations e.g., capital injection, availability payments, contract for difference, cost + margin, incentive payment at closure date,
- Cost recovery of these arrangements would need to be funded by the state government e.g., through DUoS charges.

The ESB acknowledge an OEMC is one of many alternative options that may be considered to address any potential risks moving forward. The intention of the integrated process is to identify all risks and facilitate an assessment of those alternative options. It is not the ESB's expectation that at the end of the integrated process some form of intervention will occur or that governments will only look to contract with a retiring generator. Acknowledging this, the ESB is conscious of moral hazard risks associated with options of this type and will continue to consider ways to mitigate this risk towards June.

Any OEMC type arrangement entered by a state government should be kept separate from RERT arrangements. The arrangements supporting how and when AEMO may utilise RERT are intentionally prescriptive and focussed on resources that are typically short duration like demand response and emergency generators. In addition, the NER specifies that scheduled generation that has participated in the spot market in the last 12 months is excluded from RERT.

The ESB's recommended integrated process aims to bring forward any decision making to intervene by gathering as much information as early as possible. Therefore, the decision as to whether RERT is required will be made only after a decision to enter into an OEMC type arrangement has been taken. In some circumstances a residual reliability exposure may remain, particularly if the reason for the generator retiring was technical in nature. AEMO would factor this new arrangement into its reliability assessment before looking to enact the RERT process.

1.2. Physical RRO

This section provides additional detail on how a physical RRO scheme may be structured and operated. Specifically, it sets out the purpose, preliminary architecture, market function and expected impact of a proposed physical certificate scheme in order to assist meaningful engagement over the course of the consultation period.

Purpose of a NEM physical certificate scheme

The ESB expects that the commercial sector will continue to undertake the majority of new investment and that the real time market will be the primary driver of efficient dispatch and future revenue expectations. The purpose of the proposed physical RRO option would be to provide supplementary investment signals to increase certainty of resource adequacy. This is different from a typical capacity market, where projected net revenues from energy sales tend not to be the key driver of capacity investment.

A physical RRO scheme is intended to provide confidence that physical resources will be in the market in advance of potential capacity shortfalls. The scheme seeks to encourage timely and earlier contracting of physical resources only when the need is identified – likely on high demand days – in the event that forecast capacity shortfalls exist, notwithstanding the reliability settings.

A physical RRO scheme would require retailers to acquire certificates to cover their own load liabilities. In this sense, the scheme would be supplementary to the energy market. It will reduce the likelihood of AEMO having to procure RERT and, in the event RERT is required, will reduce the quantity of RERT that AEMO is required to procure.

Importantly – and in contrast to the modified financial RRO option – the physical RRO is a certificate scheme. It is not intended to be an electricity energy market derivative product. As such, the definition of an RRO qualifying contract would need to change. Currently the National Electricity Law (NEL) defines an RRO qualifying contract as one that:

> *(i) is directly related to the purchase or sale, or price for the purchase or sale, of electricity from the wholesale exchange during a stated period; and*
>
> *(ii) the liable entity entered into to manage its exposure in relation to the volatility of the spot price;*[3]

[3] Section 14O(1) of the National Electricity Law.

A move to a physical RRO would seek to change the definition of a qualifying contract, and could look something like:

(i) consists of certificates approved by AEMO to manage compliance with the Retailer Reliability Obligation

Certificates will relate to the physical capacity that will exist and can be deployed on the relevant days. The scheme would be sufficiently enforceable and technology neutral, with a compliance regime that respects the inherent capabilities of different plant and demand curtailment options.

Architecture of a NEM physical certificate scheme

The proposed features of a physical certificate scheme and the objectives of those features are described in Table 1 below. The architecture revolves around the creation and trading of certificates as well as enforcement mechanisms. The straw-person presented in the Part A Chapter 2 represents a hypothetical example of how a physical RRO could work and alternatives for key design choices. This attachment seeks to provide more detail regarding the optionality of the features that could be combined to form a physical certificate scheme. Some of these features will require further consideration and development prior to finalisation if a physical certificate scheme option is recommended by the ESB.

Table 1 Proposed features of a physical certificate scheme:

Feature	Key objectives/directions	Issues for consideration
Trigger	A degree of optionality exists with how triggers are applied in a physical certificate scheme: • Triggered with a forecast breach of the reliability standard/projected reliability gap at T-3 • Triggered by jurisdictions at T-3 • Removal of triggers and replacement with a continuous obligation assessed at T • Consideration of the role of a T-1 trigger as a compliance tool for ex-ante certificate position assessment.	The implications of all different trigger options will need to be considered in detail. • Retaining a T-3 trigger mirrors the current RRO structure and provides some forecast certainty over periods where certificate positions may be necessary and assessed for. Removing it will likely expand the demand for certificates and an provide improved forward signal. • The function of a T-1 trigger is being reconsidered. Consistent with the current RRO, where the physical certificate scheme will only be triggered at T for days that exceed a designated probability of exceedance. If a T-1 is removed, a further trigger at T could be whether RERT was actually used (as a signal of stress to reliability).
Certificate creation	The certificate creates an obligation on suppliers. The certification process would need to reflect the timing of any triggers (ie occur following a T-3 trigger) or if continuous	Who should certify? • Issue: Qualification of certificates can be centrally determined e.g., by AEMO, or de-centrally determined by generators. If the latter is chosen, it will

	provide sufficient lead times and provide a long enough window for liable entities to adequately manage risk. The certification process need to be continuously available, so new • resources can be certified. • Certificates need to detail the MW related to the generation, at the regional level. • Capacity is accredited for their capability to contribute to reliability during 'at risk' periods. Each certificate represents a firm MW in a region for a defined period. • Any generation can be certified, including VRE, demand response and storage. The certification will consider the ability for the capacity to be deployed during the defined 'at risk' period, with compliance assessment measures varying depending on the form of technology the subject of the certificate.	need strong monitoring/compliance of certificate obligations to ensure that the sale of certificates by a generator reflects their actual capability.
Trading	Trading of certificates creates an investment signal. Trading: • Requires a liquid supply. • Should be easily accessible for all NEM participants. • Encourages price discovery for physical resources for POE50+ days, which needs to be visible to all market participants. • Trading should be bid and offer style based on price. Sellers and buyer's identities should be anonymous, in the same way that derivatives are shown on screen on the ASX trading platform. • Trading should be allowed up until T	How should trade take place? • Issue: All trading could be required to take place on a platform operated by AEMO. This would maximise visibility and access of certificates to smaller retailers and generators. Liquidity obligations could also be actioned through the platform, minimising compliance costs of these obligations. Alternatively, trading could be in multiple places, including OTC/bilateral, which could mitigate the costs of establishing a platform.
Regulating	Regulation of the supply-side of the physical certificate market will be important to delivering reliability in an efficient manner. The physical certificate scheme will likely require: • protection against withholding, and need a liquidity obligation on generators • some form of confidence that the physical amount expressed in the	When should regulation be focused? • Issue: Regulation can either be strongly targeted upfront with certificate creation, and/or strongly targeted at T, including methods to assess availability for the different technologies

	certificate will delivered when expected. • Penalty pricing to limit exposure • Compliance approaches to assess availability at T should reflect a market participants portfolio position in a region. Compliance with certificates should not be focused on specific plant/unit availability	

Market Function of a NEM physical certificate scheme

This section seeks to acknowledge the prominent market functions and dynamics that a physical certificate scheme would have interactions with, to inform stakeholders of the ESB's intended development direction.

As noted in the resource adequacy chapter, the NEM is transitioning from a period of relative resource adequacy abundance to period of potential transitory scarcity, as the generation mix evolves and the precise timing of entering and exiting units remain prone to uncertainty. Physical certificates – valued for their firmness and design in a manner consistent with the previous two sections – will therefore fluctuate in price as the needs of the power system change and the risk management processes for retailers adjust accordingly. In this sense, a physical certificate scheme can support the resource adequacy needs of the system.

Under one model the scheme would be intended to support the investment signals currently provided in the energy only market. The scheme would buffer the modelling assumptions used to formulate the market price settings (e.g., reliability standard, market price cap, cumulative price threshold) if despite best efforts, inherent uncertainty means the future could be different to what assumptions are adopted in modelling. If the Reliability Standard was changed, and/or if the reliability settings change (that is, risks increase or decrease). It may change the value of the certificates, but it will not change the need to provide a buffer to provide confidence of timely entry and orderly exit. Establishing an appropriate penalty price and contracting level by retailers will be very important to ensure the scheme supports reliability within the current Reliability Standard. The Reliability Panel could advise on these elements.

Alternatively, a 'physical RRO' could be designed to replace the current market signals for reliability investment. This would necessarily require a review of the market price settings to ensure that the combined effect of the energy only market and the 'physical RRO' were more than necessary to drive investment.

Providing confidence that resources will enter the market in a timely fashion and exit in an orderly manner y is essential if the scheme is going to discourage government intervening in the market and underwriting generation, particularly dispatchable generation.

Impacts and market participant categories

Any physical RRO scheme would need to be designed in a way that does not present asymmetrical barriers for smaller retailers and C&I customers. For this reason, the chapter offers a range of current considerations for large customers and C&I customers to remain. The considerations of liquidity obligations and transparent trading platforms are also key to providing smaller retailers and smaller NEM participants the ability to buy and sell certificates.

The physical certificate must also not disadvantage VRE, storage and demand response resources if they can confidently provide capacity during at risk periods. Maintaining the prominence of the energy-only market in encouraging investment, including its volatility, will maintain the present incentives for demand response, storage and VRE to be available and find value in the market. Compliance mechanisms and certificates under a physical RRO scheme could be created in a manner that is sensitive to characteristics of scheduled, semi-scheduled, non-scheduled and demand response resources. The objective is on the ability to be deployed when the system needs it, irrespective of technology type.

2. Essential System Services, Scheduling and Ahead Mechanisms

This document contains further information for the reform options considered under the essential system services (ESS) and scheduling and ahead mechanisms (SAM). The information includes:

- Summary of stakeholder feedback to the AEMC's Frequency Control rule changes (section 2.1)
- Further consideration and development of the design of a Unit Commitment for Security (UCS) and System Security Mechanism (SSM) (section 2.2)
- Summary of stakeholder feedback to the AEMC to AEMC's Operating Reserves rule changes and an approach to issues relevant to the design of an option for reserves (section 2.3)

2.1. Frequency Control

The ESB has prioritized for immediate reform the refinement of frequency control arrangements and, in particular, addressing the potential need for enhanced arrangements for primary frequency control and a new market for fast frequency response.

Fast frequency response market ancillary service rule change

As reflected in the AEMC December Directions paper,[4] the development of spot-market arrangements for the provision of FFR is preferred. The high-level market options for the provision of contingency FFR are:

- Option 1 – new market ancillary services to procure FFR FCAS
- Option 2 – reconfiguration of the FCAS arrangements to procure FFR through the existing service classifications.

In response to the AEMC's Directions Paper, most stakeholders agreed with the development of spot market arrangements for FFR where the procurement, pricing and cost allocation for FFR would be based on the existing contingency FCAS arrangements (i.e., option 1).

Most stakeholders supported the development of new FCAS products (option 1) as this is perceived to have less impact on the existing registration of FCAS providers. Origin and the South Australian Government expressed a preference for re-tasking the existing fast FCAS products (option 2) to avoid increasing complexity.

The ESB acknowledges the close interaction between the development of market arrangements for FFR services and the valuation of inertia provided above the minimum levels. The NER currently includes an inertia framework that supports the provision of inertia to meet the power system requirements for satisfactory and secure operation for each of the NEM regions, referred to as inertia sub-networks. However, the existing NER do not support the full valuation of inertia above minimum levels. The ESB's reform pathway for valuation of inertia services is described in Part A.

[4] https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf

Primary frequency response incentive arrangements

In its December Directions paper, the AEMC identified three viable pathways towards enduring PFR arrangements. These three pathways are defined by three different approaches to the enduring role for mandatory PFR and the associated frequency response band.

In summary, the three pathways to enduring PFR are:

1. Maintain the existing Mandatory PFR arrangement with improved PFR pricing.
2. Revise the Mandatory PFR arrangement by widening the frequency response band and develop new FCAS arrangements for the provision of PFR during normal operation (AEMC's preferred option)[5]
3. Remove the Mandatory PFR arrangement and replace it with alternative market arrangements to procure PFR during normal operation.

The AEMC received 29 submissions to the Directions Paper. Unlike responses to FFR, which generally concurred with the concept and need for a co-optimised spot market, stakeholders expressed a range of views in relation to the PFR rule change. While most stakeholders expressed support for market or incentive-based arrangements for PFR, there was a divergence of views on the enduring role of a mandatory PFR arrangement. A number of stakeholders expressed support for the abolishment of any form of mandatory PFR obligation.[6] Many respondents agreed with the premise of widening the frequency response dead band, consistent with pathway two above, to allow a new PFR FCAS service to be implemented, but some questioned the requirement for procurement of new reserves for PFR, given FCAS reserves are already acquired through Contingency and Regulation FCAS. A small number of stakeholders expressed support for the continuation of a mandatory PFR arrangements at a relatively narrow frequency response setting to provide consistent active power control as a basis for secure power system operation.[7]

A related issue raised by UNSW and Infigen is the suggestion that the market and regulatory frameworks in the NEM should clarify how frequency responsive reserves should be utilised in the NEM and whether reserves for frequency control during normal operation should be common or separate to contingency reserves.

The majority of stakeholders accepted the AEMC's position that a mandatory PFR dead-band of some kind is required, thus leading to few endorsing pathway three.

The high-level issues related to the Primary frequency response incentives rule change include:

- Consideration of the role of a mandatory generator obligation to provide continuous narrow band primary frequency response.
- Whether there is a need for additional market ancillary service to provide for continuous narrow band primary frequency response. This includes consideration of how frequency responsive

[5] Noted as AEMC preferred option in the AEMC Directions Paper on Frequency Control. Found here: https://www.aemc.gov.au/news-centre/media-releases/directions-paper-published-new-arrangements-frequency-control (p16).

[6] Submissions to the AEMC Directions paper – Frequency control rule changes, 17 December 2020: Alinta, p.5., Energy Australia, p.6, Origin Energy, p.5., Snowy Hydro, p.9

[7] Submissions to the AEMC Directions paper – Frequency control rule changes, 17 December 2020: AEMO, p2., Hydro Tasmania, p.5., UNSW, p.19

reserves are specified and utilised in the NEM and whether there should reserves for frequency control during normal operation that are either common with or separate to contingency reserves.

- The feasibility of operating a new primary frequency response regulating service.

The AEMC is in the process of co-ordinating the provision of technical and economic advice and analysis to inform its determination of the appropriate enduring PFR arrangements. This advice will be informed by plant and system data collated over the phased implementation of plant control system changes associated with the mandatory PFR requirement. It will include:

- technical advice from AEMO on the plant and system impacts of mandatory PFR and the operational feasibility of the identified enduring PFR pathways.
- analysis by the AEMC to measure and describe the operational impacts associated with plant operating in accordance with the mandatory PFR arrangements.
- independent advice commissioned by the AEMC to inform the selection and design of enduring market and regulatory arrangements for PFR.

2.2. Structured procurement and scheduling mechanisms

The objective of this workstream is to ensure the availability of resources and services required to dispatch and deliver secure supply, without relying on system operator interventions, while supporting investment in the necessary capability.

Previous ESB papers have described the changes in the resource mix, and as a consequence, a fall in the capabilities to provide services that are essential to the secure operation of the power system. While the fundamental power system requirements are unchanged, the changing resource mix (exit of thermal synchronous generation units, entry of significant volumes of DER and VRE), is changing the technical envelope, the physical dynamics of the power system, and the suite of resources that can deliver the range of essential system services to maintain security. For example, the growth of asynchronous generation and loss of synchronous generation has caused particular issues in recent years with system strength. Considerable work is underway by the AEMC, AEMO, AER and the ESB to put in place measures to ensure system strength is procured without the need for directions.

This section provides additional detail regarding the immediate reforms under consideration with regards to those system services that currently are unable to be integrated into the real-time market and so may be subject to structured procurement arrangements in the near term. Services procured through structured procurement arrangements will be those where there is no spot market, and so will include, system strength, inertia & voltage. For example, for system strength, the structured procurement approach is expected to be supported by a new planning framework for proactive provision of system strength by TNSPs, above the minimum required for system security.

The major supply of some services required for system security currently is from conventional, slow start generators. Maintaining adequate system strength on a dispatch interval by dispatch interval basis will require action sufficiently ahead of dispatch to allow further resources to be brought online if needed. This will be necessary to dispatch generators under longer term contracts to TNSPs.

To complement the long-term structured procurement, the ESB considers that an operational scheduling mechanism (described below), and potentially short-term procurement, should also be considered. The potential mechanisms under consideration are further described in this attachment, with stakeholder input sought on the design principles.

Investment Timeframe

The AEMC is progressing a rule change submitted by TransGrid to evolve the existing system strength frameworks to provide system strength in a more proactive manner, to maintain a secure power system, and to provide additional levels of system strength to streamline the connection of new non-synchronous generators.[8] A draft rule determination is due by 29 April 2021.

In the final report of its Review of system strength frameworks in the NEM,[9] the AEMC set out an evolved TNSP led approach for the provision of system strength. This model was intended to proactively deliver the needed volumes of system strength to manage inverter driven instability, which is critical to facilitating the transition. This framework consists of three parts:

- A TNSP led planning process, incorporating a network planning standard, which will require TNSPs to proactively provide the system strength needed to support efficient levels of expected new generation and load, as described in AEMO's ISP.
- Changes to the generator access standards to ensure that generators use the efficient level of system strength.
- A charging mechanism to share the cost of the provision of system strength between generators and customers.

The network planning standard is intended to utilise all available technologies in order to proactively provide fault level as new resources connect as well as to help support general power system security. This may include building network assets, retuning generator control systems, or contracting with synchronous generators who supply system strength.

Initially, some non-network solutions may include contracts between the TNSPs and synchronous generators for those resources to be online to provide the required support services. Contracts would form part of the portfolio of solutions where these have been identified as being the lowest cost means to meeting the TNSPs obligations under the planning standard, including requirements to maintain system security while meeting the relevant system strength fault levels.

The new planning framework would oblige TNSPs to provide the efficient level of system strength based on planning assumptions of generation costs, future operation and forecast connections. Given synchronous generators have been proven to support an operable system, it is expected contracts with those resources may be utilised to maintain system security, for example through periods where TNSPs build network solutions and engage in possible control augmentation. Contracts with new or existing resources could also form part of longer-term solutions where these are the lowest cost option. The objective of the planning framework is to enable efficient new investment to support an operable envelope for the power system going forward, and efficient utilisation of existing and new resources.

8 Efficient management of system strength on the power system, ERC0300, https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

9 https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem

As part of developing an enduring framework for system strength, it is important to consider the potential interactions between mechanisms in the operational and investment timeframes. As such, the ESB and the AEMC are working in concert through the parallel processes of defining the planning framework requirements, how these will be scheduled in the operational timeframe, and how shorter-term procurement frameworks may be complementary.

Operational Timeframe

The aim of the scheduling mechanism (UCS as further described below) will be to provide an objective and optimised assessment of when and how these resources will be utilised, providing confidence the system will remain secure, scheduling to efficient levels for consumer benefits. While there is uncertainty regarding the number and timing of contracts that may be signed between TNSPs and resources, the ESB considers it is prudent to design and consider implementation of a scheduling mechanism pre-emptively. It is recognised that it may be unnecessary to implement a complex scheduling mechanism that only schedules contracts (UCS) if there are only a handful of contracts to optimise. However, with the counterfactual being that there could be more contracts than are able to be scheduled efficiently, the ESB considers that there is a need to consider the relevant scheduling mechanisms for those contracts, such that appropriate mechanisms can be in place to manage these in line with when the current simpler tools become untenable.

Further, the ESB is considering a short-term procurement mechanism (SSM) to assist in managing the power system where the planning framework has not been able to account for all operational conditions. This could be due to many factors that are different in a planning and operational context – e.g., because the actual development of the system did not meet planning expectations, the specific operational conditions of the day were not part of the planning considerations, resources that can address the system need are available that were not already contracted, or because new knowledge or detailed studies reveal changes the system limits from those assessed in a planning timeframe and these require a shorter-term solution. In this way, planning timescale mechanisms can be complemented by operational timescale mechanisms to schedule the associated resources under long-term contracts, provide flexibility in operating the system, and potentially as a means for shorter-term structured procurement to account for the differences between the operational conditions and the assumptions in a planning timeframe. Parallel considerations of the mechanisms also ensure that the regulatory design for the planning framework can be aligned with the framework for the operational timeframe, for example, any requirements for contracts to ensure they will be scheduled through the UCS.

The ESB remains committed to some form of scheduling mechanism to efficiently schedule any resources providing system security services that are not accounted for in the real-time market prices or settings (including constraints). This could be through a UCS that efficiently schedules any synchronous machines (generators or condensers) that have contracted over the planning horizon with a TNSP or could be extended to accommodate an SSM that provides a mechanism for additional shorter-term procurement by AEMO to enhance dispatch outcomes and operating flexibility.

The ESB is interested in receiving feedback from stakeholders regarding these two options, and further information on their specific mechanics is provided in this section.

The potential short-term procurement mechanism (the SSM) is first discussed, followed by further elaboration on the scheduling mechanism itself (presented as a UCS-only model). Note, the ESB

January Directions Paper also contained further details for these options that may also aid the consideration of these proposals.[10]

System security mechanism (SSM)

Over and above a UCS-only option, the ESB is considering whether a system security mechanism (SSM) could enhance the long-term procurement of system security resources by providing a mechanism for resources to be procured on a shorter timeframe and scheduled alongside longer-term contracts. This section outlines the key drivers for an SSM and a proposed design.

The drivers for consideration of an SSM are centred around the following two objectives:

- Providing flexibility to manage operational conditions using all available resources that offer to address the system constraints that apply on the day. The SSM would be used to ensure the required configurations of the system are online to maintain power system security – including for system strength, potentially inertia, and general power system security. In other words, it would be used to procure any system services that are not already provided through a real-time spot market. This could support the procurement of additional services needed to maintain general power system stability, to complement those provided through the TNSP led, investment timescale procurement mechanism.
- facilitating more efficient dispatch outcomes by providing a means for structured procurement of system services on a short-term basis via some form of ahead auction for commitment (in addition to any longer-term contracts).

The ESB is also exploring whether an SSM may:

- Support synchronous generators' ability to contract with the TNSP by introducing an operational procurement mechanism which highlights the operational need for these services.
- Lessen the likelihood of "uncontracted" synchronous generators' (or other units providing services under structured procurement arrangements) de-committing in the energy market if they have an opportunity to offer into the SSM and receive a short-term contract, by remunerating all relevant providers of the services, not just synchronous generators with long-term contracts, and
- resolve operational requirements by providing a mechanism that allows for scheduling of the necessary resources to support an operable envelope of the system, where the real-time prices and scheduling do not necessarily do this.

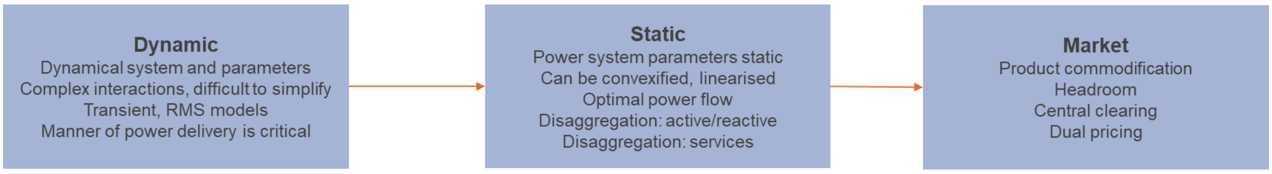
These challenges and opportunities are further discussed below, leading to the ESB consideration that such a mechanism may provide a useful tool to support the transition to a power system that increasingly utilises different technologies, other than synchronous generators, to support system strength and general power system security.

Translating physical requirements to a market structure

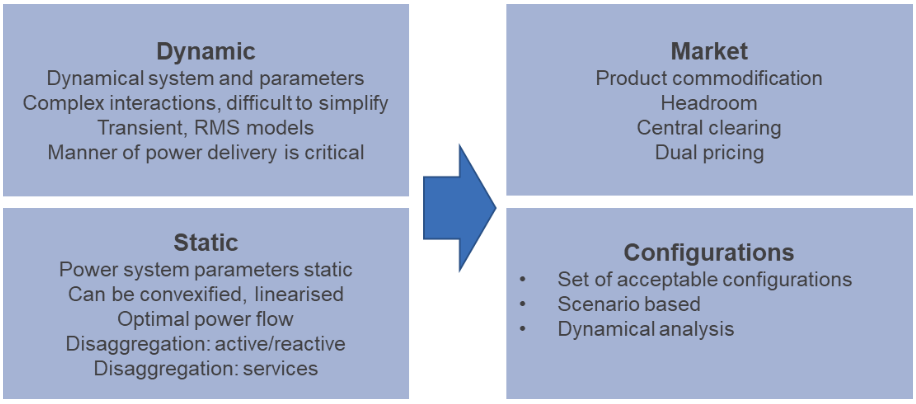
Historically, ancillary service market development has relied upon the ability to transform dynamic and time-varying power system relationships into static power flow constraints. These constraints are

[10] This detail has not been repeated here. The relevant content can be found in Section 4.2.5 to 4.3 (pages 46-54), ESB Directions paper, https://esb-post2025-market-design.aemc.gov.au/32572/1609802925-p2025-january-directions-paper.pdf

typically converted into a mathematically simpler linear and mixed-integer constraints that can be handled by large-scale commercial optimisation software. This codification of power system relationships into optimisation constraints has enabled a disaggregation of power system requirements into services related to active and reactive power reserve and for these services to be procured via a centralised market.



This approach to commodification was underpinned by a set of common assumptions on power system technology including the provision of system inertia, fault levels and synchronising torque from rotating generation units. As the power system transitions to more inverter-based technology, the traditional assumption that the grid will be secured by rotating generating units breaks down. Moreover, as the technical understanding of the new security phenomena continues to develop, new static power system relationships have to date not emerged.



Instead, on current analysis of security phenomena, system constraints and transfer limits are formulated to ensure a certain combination or combinations of synchronous generation are online so that the power system meets system security requirements for stability[11]. These configurations will evolve with increased new generation and load and evolving power system knowledge, with the SSM providing flexibility to manage the operability of the system through the transition. This suggests that real-time market approaches to procuring services must sit side-by-side with a set of acceptable configurations that provide comfort that the system is in a secure or satisfactory operating state until further understanding has been gained about what services exactly these configurations provided. Once this learning has been undertaken, specific mechanisms to procure such services, rather than specific configurations, can be put in place.

In the absence of a real-time market, a scheduled procurement approach is desirable to ensure that the power system is operating under acceptable configurations. An SSM could provide an efficient and transparent mechanism for the structured procurement of system services to enable acceptable power system configurations. This could advance the current practice with relation to minimum unit

[11] AEMO provides transfer limit advice and constraints for power system security. Current transfer limit advice is available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice

configurations for system strength in South Australian and other regions by also considering how the services provided by developing resources (e.g., grid-forming converters) can aid in achieving the acceptable power system configurations once they are proven to be able to do so. The scheduling of resources under the UCS would be based upon operating the grid under these acceptable configurations.

Mechanics of an SSM

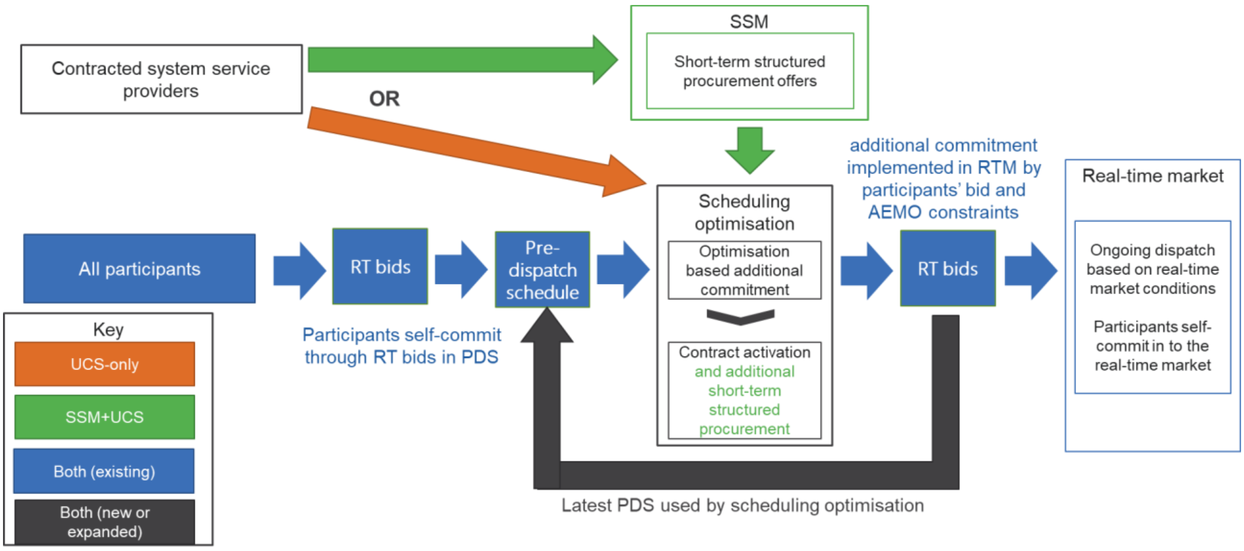
The SSM could aid in ensuring that the dispatch of the system will remain within an operable envelope through unit commitment and scheduling of services not traded in the real-time market (i.e., system strength). If an SSM was deemed to be needed, then obviously the UCS would require modification in order to accommodate that. There are two options as to how that could happen:

- the SSM could introduce a simple short-term procurement auction (which would then be scheduled in an optimised manner in a UCS – as described further down in this attachment), or
- the procurement occurs as the SSM forms part of the optimisation process itself through the UCS – as described immediately below.

Based on the schematic in Figure 4, the key elements of the SSM mechanism include the following:

- The SSM will use the pre-dispatch schedule (PDS) as the prime mechanism for decision-making on the level of incremental unit configurations required for security. This is in order to ensure that the NEM continues to function primarily on a 'self-commitment' approach.
- The scheduling optimisation will accept offer price and quantity inputs from contracted system service providers (contracted by relevant TNSPs under the system strength planning framework), and other participants in the market. These offers will be provided by participants and informed by forward commitment projections in PDS.
- By sourcing offers from both contracted and non-contracted participants, the SSM could comprehensively procure a set of commitments that meet system security requirements.
- Any additional commitment procured by the SSM would be implemented in the real time market by participant offers and AEMO constraints. All other participants would remain free to self-commit into the market in real-time.

Figure 4 Scheduling mechanism schematic



The SSM would be used to support operations through the transition, allowing for evolving configurations as there is confidence the system will remain secure operating in that way. Potential use cases include regions with high or rapidly developing renewable project build, and regions experiencing risks to instability from the interaction between synchronous and non-synchronous resources. It also allows the development of future services that reduce reliance on ageing thermal plant – as and when non-synchronous plant (e.g., via grid-forming converters) are able and proven to provide the services required for keeping a system stable.

Questions for consultation:

1. What are stakeholder views on the interactions between the proposed investment and operational procurement mechanisms for structured procurement?
   1.1. In what other circumstances to the ones listed in the paper would having both mechanisms be complementary to one another? How should they be designed to support this complementarity?
   1.2. In what circumstances might having both a long-term and short-term procurement mechanism potentially cause unintended consequences? What should be done in the design to mitigate these risks?
   1.3. What are the potential impacts, in either or both mechanisms, for the different segments of industry, for efficient investment in transmission and generation, and efficient operation of the system?
2. How do stakeholders envisage contracting arrangements will work under the long-term procurement mechanism, and how may this interact with the design of the SSM or vice versa?

Unit Commitment for Security

The UCS is an optimising tool that could assist AEMO to schedule system services acquired through structured procurement to an efficient level. To deliver services at an efficient level, the UCS should be configured to minimise the total system wide dispatch costs over a predetermined scheduling horizon. This would enable AEMO to commit additional resources to provide system services in an operational time frame at a level that would recognise the trade-off between the cost of dispatching more system service against the benefit of having lower cost generation dispatched.

Context

This section explores the detailed design considerations for the UCS, if it were to be implemented on its own, independently of a system security mechanism (SSM). As noted in the January Directions paper, the need for, and design of, a UCS is being progressed through the AEMC's consideration of the Capacity Commitment Mechanism rule change request submitted by Delta Energy.[12]

As also noted in the January Directions paper, the consideration of an SSM, is being undertaken by the AEMC through its consideration of the Synchronous Services Markets rule change request submitted by Hydro Tasmania.[13] As noted above, if a SSM was implemented this would have direct consequences for how the UCS operates.

The ESB will work through the next phase to understand these differences further. In this attachment, for simplification, the scheduling design is presented as though the UCS only schedules resources that have been procured via a structured manner prior to the UCS optimisation scheduling process.

Objectives

The ESB has developed the objectives of the UCS mechanism previously outlined in the ESB directions paper.[14] The objectives of a UCS mechanism include:

- **Activate and schedule system service contracts to an efficient level** – enable AEMO to identify and activate UCS services prior to dispatch with the objective to minimise system cost i.e., activate UCS contracts if it costs less than the market benefits resulting from its activation.
- **Support for interventions to maintain system security and reliability -** provide information relevant to interventions to maintain power system security at least cost. If, following the scheduling and activation of contracts, a security or reliability requirement persists, interventions would be used as a last resort mechanism to maintain system security, while minimising costs.
- **Additional monitoring of system requirements in commitment timeframe** - provide information to allow for additional monitoring of power system security requirements in the period prior to a dispatch interval. This function would leverage existing AEMO monitoring processes (PASA and PD) and regularly monitor the self-committed schedules of the fleet.
- **Improve transparency** – the scheduling of contracts would communicate to the market that additional units have been committed and allow other participants to respond. It would improve transparency and predictability for the market.
- **Minimise interference with self-committed participants -** ensure that any generating unit or scheduled load that is being used to provide a UCS service cannot be used to set the dispatch price

[12] Capacity commitment mechanism for system security and reliability services, ERC0306, https://www.aemc.gov.au/rule-changes/capacity-commitment-mechanism-system-security-and-reliability-services#:~:text=On%204%20June%202020%2C%20the,operational%20reserve%20and%20any%20other

[13] Synchronous Services Markets, ERC0290, https://www.aemc.gov.au/rule-changes/synchronous-services-markets

[14] ESB, Post-2025 Market Design Directions Paper, p48, January 2021

for energy in the relevant dispatch interval. However, generators would be able to bid in above their contracted amount.

UCS Modes

The UCS could be operated in two different “modes”. The primary operational mode of the UCS, “scheduling mode”, will be used to schedule resources contracted to provide system services under the structured procurement framework. The UCS could also be operated in a secondary mode, intervention mode, which could be used to support AEMO interventions.

- **Scheduling mode:** In the system service scheduling mode the UCS would schedule system service contracts to provide system services acquired under structured procurement (e.g., system strength) to an efficient level (e.g., for market benefits to reduce IBR constraints in place to manage system security) when the system is in normal operation (i.e., in scheduling mode and not in intervention mode).
- **Intervention mode:** Intervention mode would assist AEMO in undertaking last resort out of market intervention (RERT, direction and instruction) to keep the system secure and reliable.

Scheduling mode

The system services scheduling mode will schedule system service contracts to provide system services to meet the objectives of the UCS in operational timeframes.

System service scheduling mode would operate under the following principles:

- Run the scheduling mechanism at either fixed intervals or on a rolling basis, for a fixed horizon.
- Only resources under system services contracts could participate in the mechanism therefore only system services acquired through structured procurement would be scheduled. Energy and system services traded in real-time markets would not be scheduled.
- Communicate the scheduling outcome and associated commitment decision at the earliest possible instance to the market.
- Commitment outcomes would be reflected in pre-dispatch by the relevant service providers under contract.
- The resulting schedule will only apply to contracted resources, all self-committed resources would have no new restrictions for rebidding.

Interventions Mode

Intervention mode may be considered a regulatory feature which refers to the collection of existing AEMO procedures related to interventions.

The UCS would provide support for interventions to maintain system security.

The design of UCS intervention mode would consider the following principles:

- not create new, replace or alter the existing collection of processes for managing interventions.
- when being used to inform the commitment of additional resources will do so in the least distortionary way, that is to minimize the impact on self-committed generation.

- allow AEMO to retain flexibility in determining how best to intervene to keep the system secure and reliable.

UCS Design Elements

The following section outlines the core UCS design elements and considerations.

Services Coverage

The UCS is a scheduling mechanism that would complement any structured procurement of system services that are not traded in the real time market (e.g., system strength). The UCS would not itself specify the individual services that are committed through the UCS. Service specification would occur through structured procurement arrangements included in the NER for the different services. Therefore, the scheduler would only commit resources that are under a system service contract by activating the contracts for the relevant scheduling horizon. It is expected that the UCS would be used to initially to schedule system strength contracts signed between the TNSP and resources. In the future the UCS could be extended to include any structured procurement of system services that do not have a real-time market and can be co-optimised with the provision of system strength. As discussed later in this section the TNSP will be the primary point of contact for these contracts and therefore responsible for the submission of these contracts into the UCS.

System service contracts scheduled through the UCS would be converted into eligible UCS bid input parameters. These parameters are required by the UCS to compare and analyse UCS contracts efficiently. TNSPs and contracted resources will be responsible for negotiating the bid inputs for this compatible format. This is discussed further below. AEMO would be responsible for preparing a procedural document outlining the eligible UCS bid input parameters. This is also discussed further below.

Net market benefit

The UCS could be configured to schedule contracted resources to an efficient level of system service by meeting a dispatch cost minimisation objective. This level would not only keep the system secure but also aim to minimise total system wide dispatch costs.

It is expected that the rules would provide a guiding principle that will specify the requirement for the UCS to meet a dispatch cost minimisation objective and for AEMO to specify how this objective will be delivered. For example, the rules could specify that meeting a dispatch cost minimisation objective will mean:

- scheduling UCS services to an efficient level of dispatch to not only keep the system secure, but to also minimise total system wide dispatch costs.
- explicitly recognising the trade-off between the cost of activating more system services against the benefit of having lower cost generation being dispatched in the wholesale market.
- requiring AEMO to use reasonable endeavours to minimise the impact on the self-commitment decisions by market participants. This is discussed further below.

In scheduling contracted resources to meet a lowest system wide dispatch objective, it is expected that the UCS will require, at a minimum, the following cost input considerations:

- Cost of activating contracted resources (as specified in contract terms) that have not bid into pre-dispatch and are available for activation.

- Cost of resources (valued by their pre-dispatch bids) that have self-committed into pre-dispatch (for the purposes of deriving total system wide dispatch cost only)
- While the scheduler will optimise for all resources in the objective function (contracted and uncontracted resources), it will only bind contracted resources that did not self-commit into pre-dispatch.

Additionally, a number of constraint considerations would have to be incorporated into the optimisation algorithm. These are expected to include, at a minimum:

- Energy demand supply balance constraints to accurately address the whole system when activating additional resources.
- IBR output constraints that would consider whether the total allowable IBR output would increase when compared with the level of system service dispatched, where this represents an outcome where lower cost generation can be dispatched, to lower the overall wholesale price.
- System security constraints to ensure that at least one of the desired combinations are online in each interval.

Therefore, in addition to the guiding principles for net market benefit the rules would also require AEMO to develop procedures that outline the specific requirements and considerations necessary to schedule resources to meet a dispatch cost minimisation objective.

It should be noted that an SSM utilising the optimisation mechanism would be expected to operate on a similar set of principles, whereby the constraints defined in the SSM would be such to ensure the dispatch is able to operate in a secure technical envelope.

Further consideration is required to be given to ensuring the UCS optimisation is not inadvertently centrally committing contracted resources by activating these for a lower total cost, when this is not related activating the contracts for the purpose of providing the service acquired under structured procurement. For example, if it is cheaper to activate a contract where this displaces higher cost generation, without specific controls to prevent it, the UCS optimisation could do so. It is expected therefore, that the UCS would only allow a specific set of constraints to activate contracts, or post-processing prior to publication of the UCS schedule will be run to confirm the contract activation was explicitly required (e.g., to alleviate an IBR hosting constraint).

Questions for consultation:

3. Do stakeholders agree that the UCS should schedule for an efficient level of the service which has been structurally procured, with the efficient level being with regards to meeting a dispatch cost minimisation objective, as defined by the terms of contract activation and pre-dispatch bids.
    - If so, why? If not, why not?
4. Do stakeholders consider the potential for the UCS to centrally-commit contracted resources to be of material concern?
    - If so, are the proposals put forward by the ESB sufficient to address this concern?
    - If not, what should be done to mitigate this concern?
5. If the UCS commits units ahead of time, how would this interact with the existing wholesale spot and frequency markets that are real-time?

Operationalising the schedule

The solution produced from the UCS scheduling mode would be one that not only considers whether there is enough system service available (e.g., sufficient system strength) to keep the system secure but will also schedule contracts for the service to an efficient level. Pre-dispatch information will be an important input for meeting both of these objectives.

For example, in the case of scheduling system strength contracts that have been entered into by the TNSP under the proposed arrangements for evolving the system strength framework the UCS would rely on PDS availability information and bids and offers to determine whether there is enough system strength to keep the system secure.

In scheduling these services to an efficient level (i.e.to meet the objective function of lowest system wide dispatch costs), the UCS would also consider PDS bids and offers as these will form the basis of assessing total system costs.

The output from the UCS system service scheduling mode is only binding for contracted resources that form part of the UCS scheduling solution, providing they have a relevant contract and have indicated that they will not be available in pre-dispatch. Contracted resources would be scheduled in line with their contracted generation capacity and will not be able to set the dispatch price except to the extent that the generator is dispatched above its contracted generation capacity.

Self-committed resources would not be bound by the UCS schedule and therefore would be free to change their bids, offers and availability any time before real time dispatch.

Contracted resources activated by the UCS would be committed into real time dispatch in line with the optimal system service scheduling solution derived by the UCS. This could be achieved by AEMO applying constraints and/or the resource making the required bids into the PDS themselves to reflect the contract activation.

Questions for consultation:

6. What are stakeholder views on how the UCS schedule should be reflected in pre-dispatch and dispatch (i.e., contracted resources being required to bid into dispatch to be scheduled and/or constraints applied)? Are there any possible unintended consequences of these approaches?

Interaction between self-commitment in pre-dispatch, the UCS and dispatch

Committing resources following a UCS scheduling run would result in a material change to the market conditions in the period prior and right up to real time dispatch. Some of these changes would be the result of external factors that could relate to the system conditions (outages etc.), fluctuations in demand and the natural variability attributed to wind and solar generation.

However, some changes may be in response to UCS commitment. Participants rebidding prior to real time dispatch could occur for a number of reasons. For example, previously committed resources might decommit in response to lower pool prices, induced by the UCS committing additional generation and increased VRE output.

This may result in the intended market benefit, originally the basis for the UCS commitment decision, potentially being undermined. For example, a self-committed unit that is part of a system strength combination might decommit in response to a depressed pool price arising from a UCS commitment decision. The UCS scheduler, having previously considered this unit available in its optimisation run, may now have committed generators into a schedule which will no longer realise the original market benefit sought, but instead could potentially even result in a system security breach.

If this issue is considered to be material, the ESB has identified a range of potential options to address this unit commitment issue, including:

- Applying the UCS schedule to all contracted resources, even those that had already self-committed.
- Incorporating an SSM such that all required resources are remunerated for providing the service if it is deemed that this will produce lower overall costs (so long as they voluntarily offer into the mechanism)
- Limiting the ability for all resources to rebid following the running of the UCS scheduling mode.

Questions for consultation

7. Do stakeholders consider the potential interactions between pre-dispatch, dispatch and the UCS to be material? I.e., that participants may change their self-commitment status following the UCS run.
8. What are stakeholders' views on the best way to address the potential decommitment?

Running the UCS

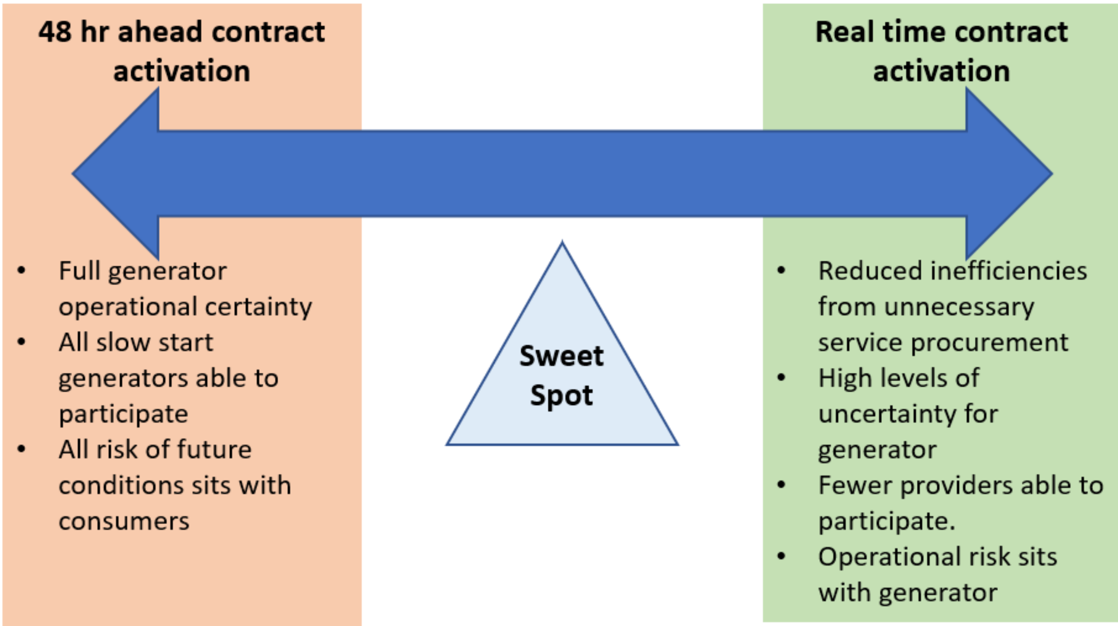
The frequency and optimisation period of the UCS is an important design consideration and is linked to the treatment of uncertainty in the process.

The core considerations of the timing and frequency of the UCS include:

- Certainty for generators and the operator. The frequency of UCS runs and the treatment of start time would impact the operational decision-making process for both generators and for the market operator.
- Risk allocation and uncertainty of future conditions. As future conditions are not fixed and there will likely be changes between forecasted demand and VRE generation and actual demand and generation. This difference between forecasted and actual conditions introduces risk to the commitment decision in the UCS.

- Computational limitations of the optimiser. There are some physical constraints that need to be accounted for in determining the frequency and granularity of the UCS runs. The UCS scheduling optimisation is not instantaneous and would take time to run. The latest estimates suggest that the optimisation would be in the order of 30 - 90 minutes.

Figure 5 Considerations for running time of the UCS



For example, if the UCS optimiser only considers the conditions for the following 6 hours, any generator that has a start time longer than 6 hours could not be called on, as they would not be able to deliver the services during the window considered. This could have implications for system strength contract design, in terms of the remuneration structure for start-up time, and the compensation for actually delivering the service.

In scheduling mode, the optimisation is driven by the 'market benefit' objective function, therefore the market operator would have a different risk appetite compared to optimising the market for purely system security and stability. That is, if a contract is not activated in time, the cost of this could be missed savings for consumers (relative to the current market design), rather than system instability. This change in implications could allow for a more probabilistic approach to scheduling.

The UCS would schedule and activate contracted resources and link long-term contracts with dynamic system requirements in the commitment timeframe leading up to real-time dispatch.

The UCS mechanism would:

- Run the optimiser at regular intervals, depending on the run time of the optimisation and the optimal scheduling horizon, to identify opportunities to schedule contract resources to the efficient level as early as possible.

- Consider a timeframe no longer than pre-dispatch over which to optimize system strength. Timeframes that are further from real-time are likely to be subject to more uncertainty that may make decisions made on forecasts less reliable, however longer timeframes ensure that resources with long start-up times can be considered by the UCS.

- Consider the cost of the uncertainty associated with scheduling units ahead of time into the decision to schedule units to optimise the scheduling of system services. This could be done through a probability assessment consistent with good electricity industry practice and taking into account:
    - Actual and forecast power system conditions and environmental or other similar conditions,
    - The likelihood of the occurrence and impact on the power system of events that are foreseeable in nature but unpredictable in timing, and
    - A prudent allowance for forecasting error.
    - Dynamic assessment of what is the contract that best maximises market benefit.

Questions for consultation:

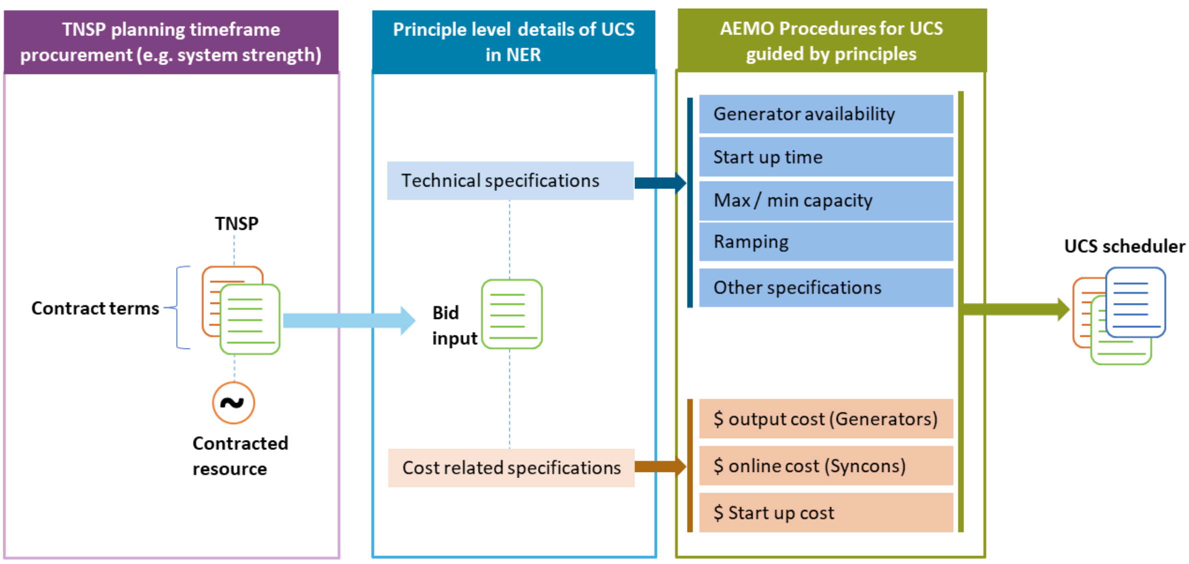
9.	How do stakeholders think that the uncertainty associated with scheduling units ahead of time in the UCS should be managed? Are there any considerations that should be taken into account in addition to those outlined above?

Interactions with system service contracts

Under the proposed evolution to the system strength framework contracts would be negotiated and settled between the resources and the TNSP. If a SSM was to be introduced such resources would be procured by AEMO. Contracts or procurement arrangements under either of these mechanisms would need to set out important commercial and technical terms under which the resource would operate should the contract be activated.

Therefore, the UCS would need a common input/bidding format for all participants to enable the UCS scheduling mechanism to analyse, compare and optimise UCS contracts effectively. These common input parameters will convert contract terms into technical and cost inputs in the UCS scheduling algorithm.

Figure 6 Interaction of the UCS with system services contracts



As outlined in Figure 6, it is expected that AEMO would be required to develop UCS procedural guidelines that outline and define the detailed bid format required for input into the UCS. These procedures would detail the appropriate cost related structure and components, technical related input parameters and any other input parameters AEMO deems necessary to form an acceptable bid into the UCS.

Contracts submitted to the UCS would only be deemed eligible if the contract can be converted into a compliant format that constitutes an acceptable bid as outlined in AEMO procedures.

This design would mean that parties negotiating contracts would have flexibility to decide on contract terms as long as such terms can be converted into an acceptable bid format required by the UCS. For example, TNSPs and contracted resources, at the same time as settling on contract terms, would agree on the technical input and cost bids that will be sent to AEMO for use in the UCS.

The ESB are continuing to work through whether system service contracts would be subject to "must offer" obligations. A "must offer" obligation would be one whereby any TNSP system service (e.g., for system strength) contract must be offered into the UCS.

AEMO is assisting the consideration of these issues by providing cost estimates of the UCS & SSM. There may be cost efficiencies by considering both mechanisms together.

Questions for consultation:

10. Do stakeholders agree with the ESB's proposal that TNSPs would be responsible for providing AEMO with the required contract information for the system service contracts, where these have been agreed between the TNSP and the relevant resource?
11. How do stakeholders envisage the contracts for system services would be designed where these are to be scheduled by the UCS, and what information would be required to be provided to AEMO to support the scheduling mechanism?
12. Do stakeholders consider that all system service contracts (e.g., system strength) should be required to be scheduled through the UCS? I.e., must offer?
    - If so, why? If not, why not?

Roles and responsibilities

AEMO would be required to honour the optimal system service scheduling solution derived by the UCS in all instances with an exception for situations where deviating from the schedule is in the interest of system security.

Generators would be required follow dispatch instructions from AEMO and bid accordingly to enable dispatch in line with the optimal system service scheduling solution derived by the UCS.

The point of contact for the contracts is likely to be the TNSP, who will submit these technical input and cost bids to AEMO for UCS scheduling. A single point of contact for AEMO for all contracts would be administratively efficient.

For contracted resources, it is expected that the contracts they enter with the TNSP could specify their obligation for following the activation schedule and the penalty for deviation. The obligation for uncontracted resources scheduled through the mechanism will be considered further in progressing the design for an operational procurement mechanism.

Transparency

The UCS should improve transparency and predictability for the market by aiding AEMO to better manage system security and improve transparency in the commitment timeframe. There should be a clear and transparent process outlining what resources have been committed in scheduling mode and what has been committed in interventions mode. The UCS should provide transparency in the operational timeframe and an annual reporting timeframe.

In scheduling mode, the UCS will produce a scheduling outcome at fixed intervals that, depending on system conditions at that time, will commit contracted resources. The outcomes of the UCS scheduling run should be communicated to the market at the earliest instance possible and commitment outcomes reflected in the pre-dispatch schedule (PDS) by relevant resource providers to provide market participants with sufficient information to enable participants to manage scheduling risk.

Transparency should be provided in relation to the scheduling run outcomes either through the MMS, AEMO website or other appropriate channel, and detail the time and location (region) that a scheduling opportunity has been identified.

Additionally, it is expected that AEMO should be required in the NER to prepare an annual report on the use of the UCS over the reporting year. The report should include the costs of UCS activation, to the extent feasible the net market benefit of UCS contract activation, and any other information deemed appropriate to facilitate transparency, including trends in UCS use.

The ESB acknowledges that AEMO already has established processes for undertaking interventions and the reporting it undertakes following intervention. Therefore, when using the UCS in interventions mode, AEMO should follow their standard reporting processes following an intervention event. That is to say:

- Post event intervention reports should provide transparency in the choice of intervention mechanism, highlighting the prioritisation made reasonable endeavours to minimise direct and indirect costs and maximise effectiveness of the intervention.
- Post-event reports should be timely.

Questions for consultation

13. Do stakeholders agree with the transparency measures proposed for the UCS implementation, or suggest other considerations exist that should contribute to transparency with regards to the UCS?

2.3. Ramping / Operating Reserve

The ESB is considering the possible implementation and design of an operating or ramping reserve service to address increasing variability and uncertainty in the NEM. The ESB is principally considering reserve services as part of the ESS workstream, while also noting that a reserve service could present a scarcity pricing signal for dispatchable capacity that could facilitate resource adequacy. An explanation of how an operating reserve could act as a resource adequacy mechanism is discussed in Part A (Chapter 2) and will be explored in further detail for the final ESB recommendations.

This Section discusses:

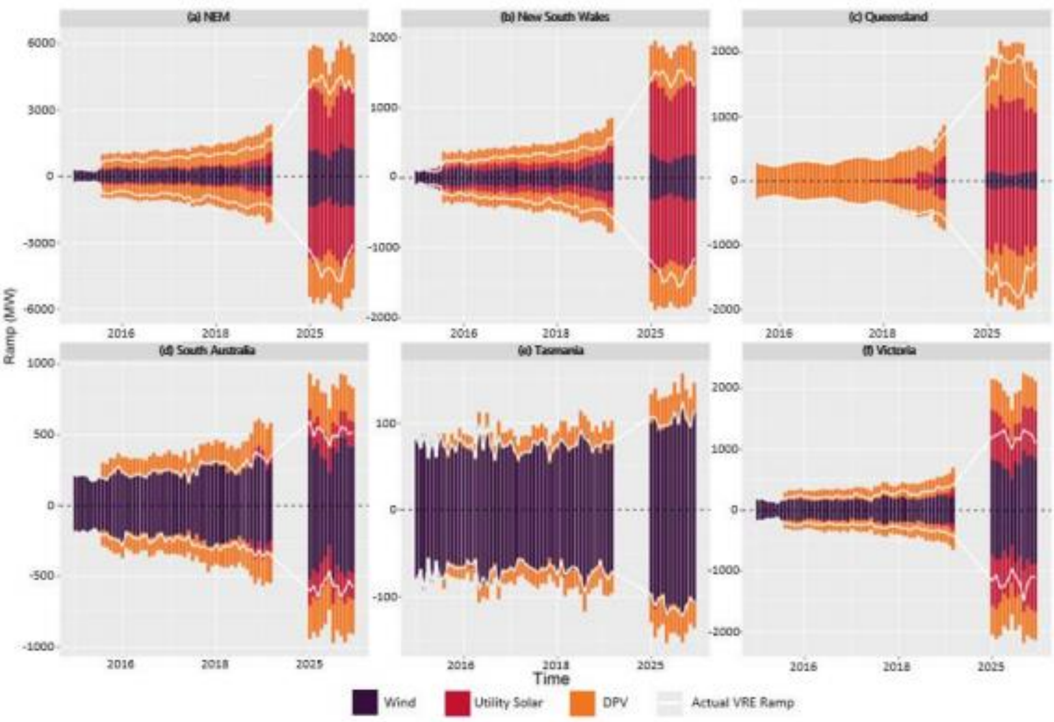
- the need for a ramping or operating reserve service, including the timing or urgency of implementation of a new reserve service, and
- interactions with current frameworks
- interactions with the AEMC Rule Change Process and Directions Paper.

We expect the AEMC will make a draft determination on the reserve services rule change requests in June 2021.

The need for reserves

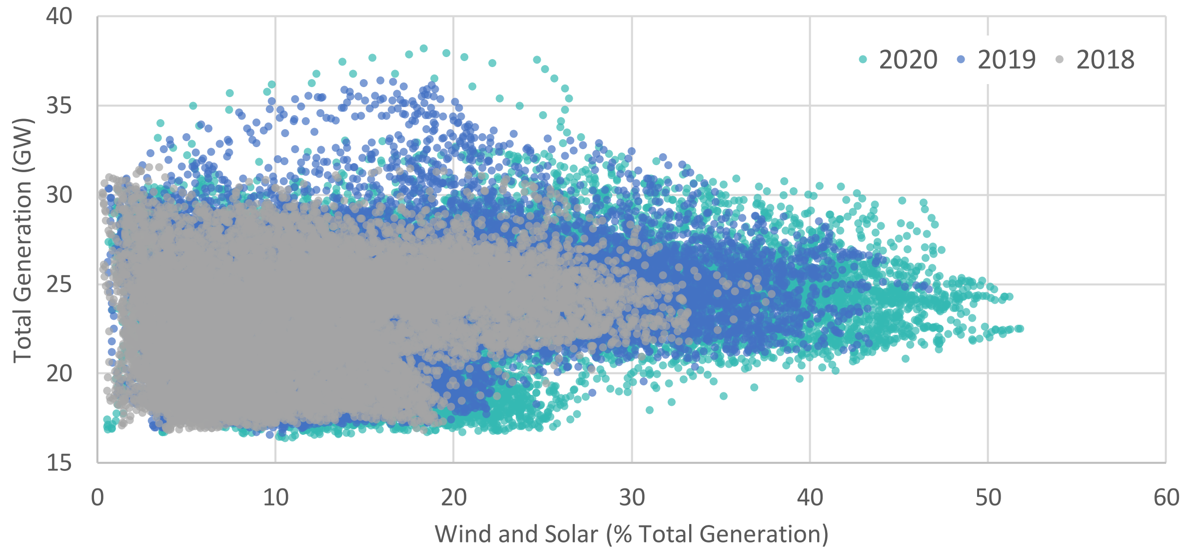
Variability in the NEM is increasing. The AEMO 2020 Renewable Integration Study (RIS) observed and projected significant increases in the variability of VRE over various timeframes, with net-demand ramps over 1.5 GW projected in a single dispatch interval, and over 6 GW in an hour under the ISP central scenario. See Figure 7 below.

Figure 7 NEM monthly top 1% of largest hourly ramps in VRE, actual 2015-19 and projected in 2025 under Draft 2020 ISP Central generation build



Instantaneous NEM-wide VRE penetration in 2020 reached 50% (Figure 8) and VRE installations are currently tracking above the central scenario.

Figure 8 NEM Instantaneous wind and solar output as a proportion of total generation, 2018-2020



This growing variability will increase the need for flexible resources to match the net load across all timescales, from very fast changes (covered by frequency control arrangements), to minutes and hours from generation, storage and demand-side resources as part of central dispatch.

A simplified representation[15] of the ability of the aggregate scheduled capacity across the NEM to ramp over various time horizons is shown for the current fleet (left) and the ISP central scenario's least-cost development fleet (right) in Figure 9.

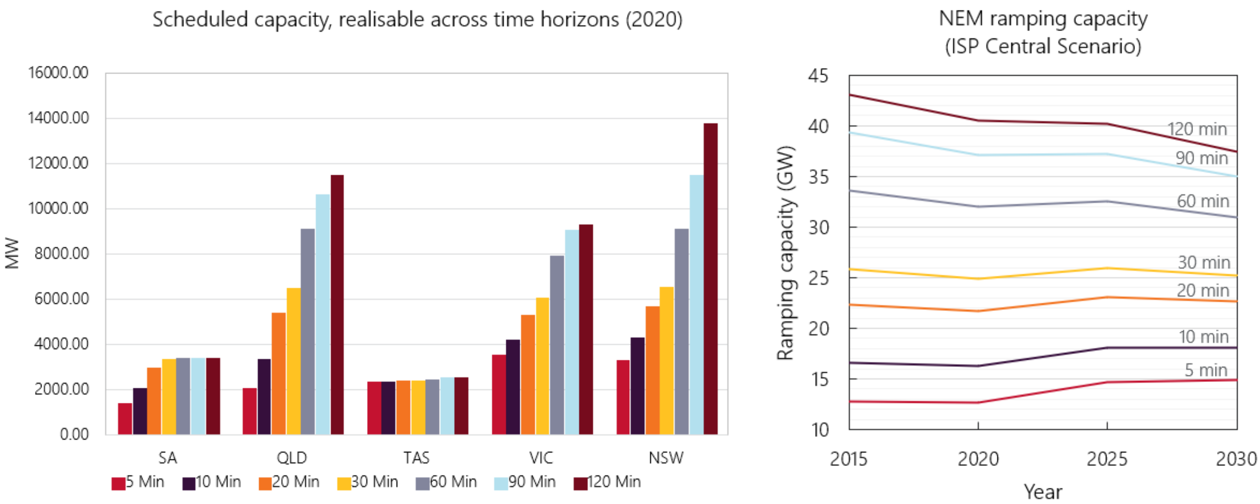
The ISP central scenario, shown below in Figure 9 (right), reflects the least cost transition pathway of the energy industry under current policy settings and technology trajectories. As noted above, the pace of VRE connections is tracking above the level expected under the central scenario. A number of developments and policy changes that impact the flexibility of capacity on the NEM have also occurred since the ISP was released in June 2020, including an additional 2 GW of firm capacity (8-12 hour storage) in NSW by 2030.

At an aggregate level, the ISP's modelling shows more faster ramping capacity and a reduction in slower ramping capacity. This largely reflects committed generator retirements and the entry of Snowy 2.0 to the NEM.

[15] Source: AEMO historical registration tables, Generation Information August 2020 and 2020 ISP central scenario optimal development path. Assumptions:

- Ramping capacity of scheduled NEM generators, assuming they are able to ramp from zero to their max capacity at their maximum ramp rate
- Start-up times or minimum stable generation levels are not factored in but are important considerations
- Future capacity withdrawals reflect commitments according to AEMO's generation information process (August 2020)
- Future capacity additions reflect the ISP central scenario (DP1)
- Assumed that all new build dispatchable capacity (all either storage or DSP) is flexible to its full output over 5 minutes.
- Battery/hydro state of charge or plant energy limitations have not been factored in but are important considerations
- 2015 data reflects registration status, and therefore includes some plant that has been mothballed and/or retired since 2015 e.g., RedBank

Figure 9 NEM scheduled capacity realisable across time horizons



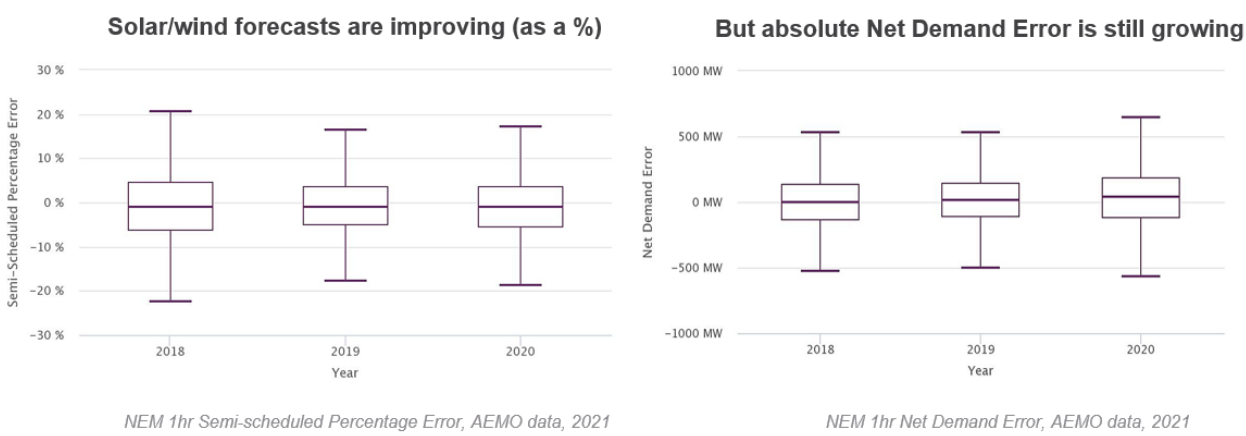
Left: By region, 2020; Right: Aggregate, 2015-2030

The critical question is whether the installed scheduled capacity will be available and physically positioned (e.g., thermal generation being online, storage having sufficient state of charge or demand response being ready to respond) to be dispatched to meet net demand changes at all times and across all timeframes, accounting for both the mid-point (or expectation) of the forecast as well as the forecast uncertainty.

The important consideration is that, in aggregate, there is sufficient capacity that can adjust quickly enough to meet the shifts in net demand. This is dependent on a number of factors including market participant behaviour and magnitude of forecast uncertainty.

Though substantial relative improvements in weather and VRE-specific forecasting techniques have occurred in recent years (Figure 10 left), these improvements have not offset growing uncertainty in net demand (Figure 10 right). An important question is whether scheduled capacity will be well positioned in operational timeframes to meet both significantly larger expected changes in net demand as well as increases in unexpected changes in net demand in line with the trajectory shown.

Figure 10 NEM semi-scheduled generation forecast percentage error and net demand forecast absolute error (one hour ahead)



Role of current frameworks

To date, operating reserves have been provided by scheduled resources keeping capacity in reserve to manage their risks in the energy market. The costs of providing operating reserves are built into the supply offers and recovered through energy prices.

Without an explicit signal for their provision, the level of operating reserves available to the system is dependent on the expected distribution of energy (and FCAS) prices and participant risk appetites. This could create potential issues if participants providing operating reserves in accordance with their own risk appetites would result in:

- an inefficient mix of resources being applied to the system needs for energy, reserves and FCAS, or
- insufficient reserves at certain times, causing increased levels of market intervention or direction (cost for consumers).

These outcomes could potentially occur under a range of scenarios, such as where flexible capacity is used to meet certain changes in net demand leaving inflexible capacity to be in reserve to meet uncertain changes in net demand, or where VRE output is high, and uncertainty is high but energy prices are low. While these scenarios may be possible, more work is needed to consider how participant behaviour is likely to evolve under current frameworks in order to determine whether there is a material risk of such outcomes eventuating.

An explicit price signal for reserves

In its report on Essential System Services in the NEM, FTI Consulting offered a number of principles:

- to deliver an overall efficient 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”

- “In general, the market design should seek to maximise market-based outcomes, such that the required interventions by AEMO are kept to a minimum.”

Consistent with these principles and the increasing value of flexible, responsive resources, the ESB is considering establishing an explicit price signal for reserves that would reflect their relative value at any point in time.

This would unbundle the costs of carrying reserves for the portion of capacity required to address unexpected events from the energy price to its own price and would be focussed on the resources providing the service. By doing so, it would be expected to drive efficient use and investment / re-investment.

The ESB considers that it is prudent to consider this now ahead of witnessing scarcities in reserves.

<u>Potential outcomes from implementing an operating reserve service</u>

This section explores the potential outcomes of implementing an operating reserve service in the NEM.

Influence on participant decision making

The potential outcomes for participant decision making of implementing an operating reserve service depend on the nature of participant decisions that would occur in the absence of a reserve service.

If one assumes that in a future with increased net demand uncertainty participants would not respond by providing levels of reserve commensurate with efficiently maintaining reliable energy supply, then implementing a new reserve service could have the effect of better positioning the fleet to respond to those unexpected changes in net demand. This could result from an incentive to provide additional ramping capacity that would not have otherwise been provided, influencing participant decisions including:

- When and if to commit or decommit generating assets or demand response resources
- To what level of output to commit resources, given technical constraints such as ramp rates
- How to manage battery state of charge, water, gas or other fuel considerations.

If, however, one assumes that under current arrangements participants would respond to the risks of price changes in the energy spot market by providing levels of reserve commensurate with maintaining reliable energy supply, then an operating reserve service to meet the same goal should theoretically have no effect in increasing reliability. There may however be risks associated with a central body choosing an efficient level that is different from the efficient level that would otherwise be provided by participants.

It is also possible that participants under current arrangements could provide an inefficiently high level of reserves, incurring costs that are greater than the costs that need to be incurred to provide for the level of reliability that consumers value. If this were the case, then implementing a reserve service could reduce the overall costs of the provision of reserves on the system by allowing a more efficient mix of resources to meet consumer needs.

The ESB welcomes feedback from stakeholders regarding how commitment and de-commitment decisions are made by participants under current arrangements, how they factor certain risks into decision making, and what this means for how participant decisions might change under a new reserve service.

Questions for consultation

14. How do generators and demand response providers position themselves under current frameworks ahead of periods of high ramping or periods of uncertainty?
15. What challenges are envisaged in a future with higher variability and uncertainty in net demand?
16. How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?
17. Who should pay for reserves and why?

An example of how an operating reserve product could co-ordinate participant decision making across the fleet to unlock additional flexibility is explored later in this section.

Interactions with the energy market

As noted above, the potential value of an operating reserve service depends on the level of reserves provided as a by-product of the energy market. Without an explicit signal for their provision, the level of reserves is therefore dependent on the expected distribution of energy prices and participant risk appetites. There are a range of potential scenarios where the level of reserves provided by participants in response to these signals could be of concern. The ESB intends to explore these by modelling the circumstances or scenarios in which a reserve service would be valuable, and then considering whether there is a risk that the NEM may experience those scenarios with a frequency that would make a reserve service a prudent change to make.

If a reserve service was implemented there should be, at any point in time, a dynamic balance of capacity providing energy and reserves, reflecting the least overall cost of providing both services. This balance would reflect the decisions of participants to bid their capacity into each market. These bids should be based on weighing up the value of providing one service over another, such as the short run and opportunity costs that attend each potential decision. In principle, feedback between the prices in each market facilitates efficient decision-making.

These interactions are similar to those between energy and FCAS markets in current frameworks. In principle, if operating reserves are procured to a level reflecting their value to consumers and their costs of provision, and co-optimised with energy and FCAS markets, then the result should be an efficient allocation of capacity and output across all markets.

Interactions with FCAS markets

FCAS markets target specific system security needs through services that are enabled on a 5-minute basis but delivered in response to frequency deviations or events that may occur at any time. In contrast, an operating reserve product positions capacity to be realised through the energy market dispatch cycle (or otherwise), potentially across multiple dispatch intervals.

The interactions between an operating reserve product and FCAS are mechanically similar to those described above between operating reserve and energy. The ESB considers that capacity should not be simultaneously allocated to FCAS and operating reserves, as the two products reflect different needs, and the addition of an operating reserve product should not undermine the delivery of FCAS.

Interaction with fleet composition

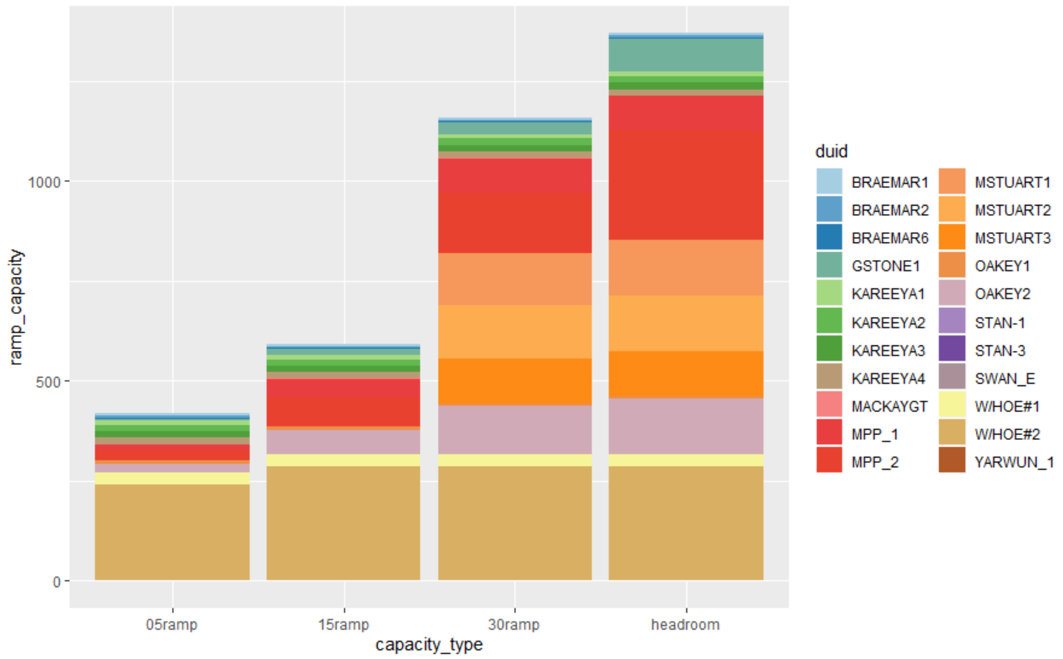
As well as potentially influencing the flexibility of the fleet in operational timeframes, an operating reserve product could influence the makeup of the fleet. The extent to which this occurs is dependent on detailed design and interactions with other frameworks. However, in principle, an operating reserve market could incentivise participation from out of market resources, including demand responses and RERT providers (noting the overlap between these two categories). As noted above, the fleet is already repositioning under current arrangements and incentives to be more flexible. The ESB is carefully considering the interactions between operating reserves, the two-sided markets and RAMs workstreams.

Case study

The ESB does not consider that this historical example is evidence of an issue, given current levels of variability and uncertainty in the NEM. The case study is presented to provide a real-world anchor through which to explore the possible outcomes of a reserve service in a more variable and uncertain future.

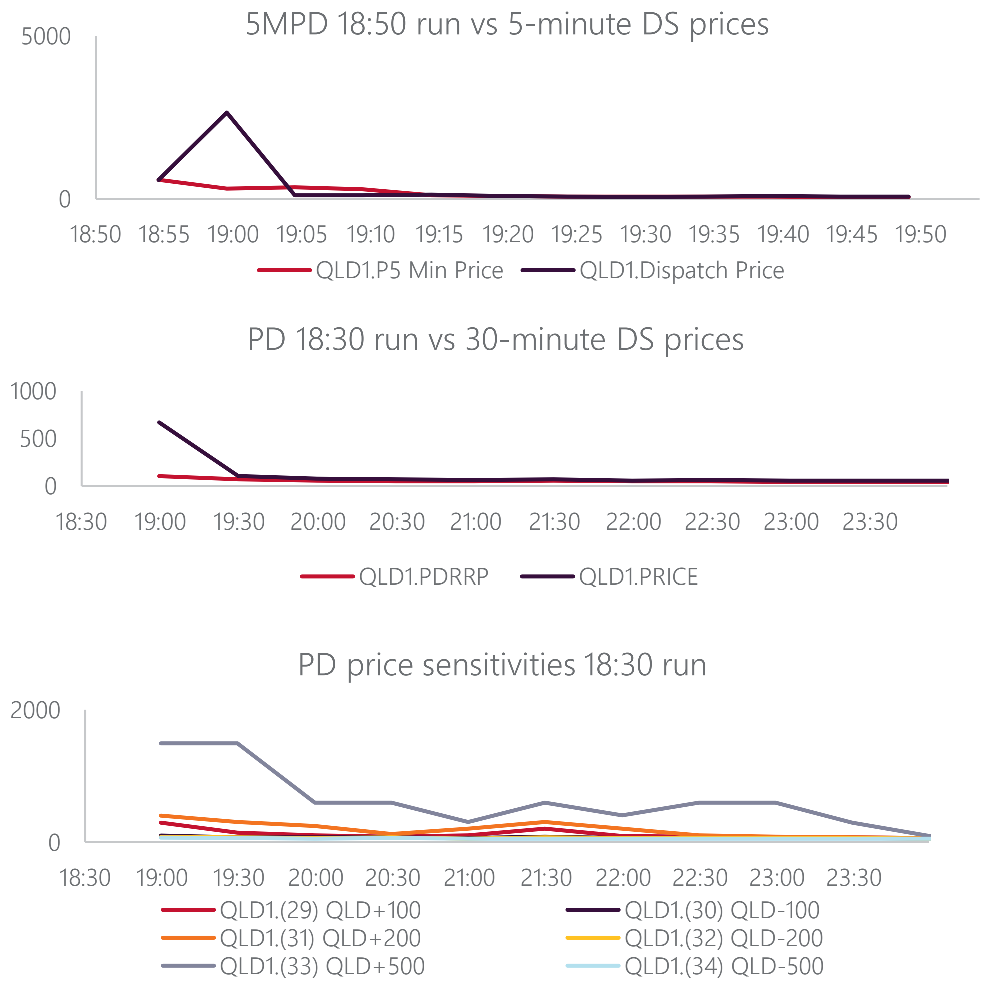
Figure 11 Scheduled capacity realisable across time horizons - QLD 6th March 2020, dispatch interval ending 19:00.

Figure 11 Realisable scheduled unit ramping capacity and total headroom



In this case study, no LOR2 notices were issued to the market, and energy price signals prior to and during the event were as shown in Figure 12 below.

Figure 12 Forecast and actual prices – QLD 06/03/2020, period ending 19:00



To consider the possible value of an operating reserve service, suppose that reserves are procured on the basis of some measure of value to consumers of insufficient reserves, scaled by probability of insufficient reserves given the net demand forecast uncertainty at the time. Suppose also that the levels of reserves shown in Figure 12, at any of the included time horizons, have non-zero probabilities of insufficient reserves associated with them. This would cause a reserve market to clear at a non-zero price and provide incentive for the provision of additional reserves. Depending on bids, constraints, and detailed design, this could result in:

- Relatively flexible units reducing their output to provide more capacity as operating reserve. For example, if Wivenhoe unit 1 (W/HOE#1) reduced its energy output by a certain MW level, this would unlock operating reserves to approximately the same MW level across any of the time horizons shown.

- Relatively inflexible units increasing their output as a consequence of the above. For example, the Milmerran units (MPP_1 and MPP_2[16]) could have substituted the energy that was being provided by Wivenhoe unit 1 if it ramped down to provide operating reserves.
- Units whose ramping capacity is limited by their start-time starting prior to being dispatched for energy. For example, the Mt Stuart units (MSTUART1-3) can ramp quickly but bid a 16-minute start time. To participate in shorter timeframe operating reserve markets, they would need to start in advance.
- Slow start units currently bid unavailable and not shown in the chart remaining in service.

Question for consultation

18. Would the fleet described in the case study have provided more ramping reserves under current frameworks if there was higher net demand uncertainty?

Market participation

The ESB considers that a broad spectrum of participants should be able to provide operating reserves. A broad spectrum of participation benefits consumers by providing depth in the market for the service, ensuring its provision is competitively priced.

Participation in the market for reserve services should be consistent with the principle of technology neutrality, which requires that there should be no unnecessary barriers to any particular technology providing a service. It does not follow that all technologies should be able to provide reserve services. The reserve service should be defined based on what the system needs, and the technologies able to provide that service should not be hindered from doing so.

In line with this approach, the ESB considers any reserve service should not unfairly discriminate between the participation of the demand side as well as the supply side. The ESB also supports, in principle, the participation of VRE in an operating reserve market. How to value operating reserve provided by pre-curtailed VRE is an important detailed design consideration.

The issues with unbundling

The need for operating reserves in the market is clear and is increasing with the growing proportion of variable generation. Unbundling this as an essential system service requires implementing one or more new markets which would incur a range of direct and indirect costs. Direct costs would include the costs of any hardware or systems changes across the supply chain to implement the new service. Indirect costs could come in the form of flow on effects of implementation, such as any costs associated with breaking and renegotiating financial arrangements that were underpinned by the energy only market structure. Unbundling would also mean that the costs of providing reserves would no longer be wholly included in the energy cost. Depending on the cost recovery mechanism for the market, customers or their representatives may need to consider how to manage any price risk for that cost.

[16] Noting MPP_2 had a feeder issue at this time and was in the process of withdrawing from service. This also influenced the actual vs forecast price outcomes.

The benefits of introducing an Operating Reserve market then need to be weighed against the additional transaction costs and additional risk management required with a separate price signal. As the need for the service grows, the benefits of unbundling, to the extent there are any, would also grow. This should be factored into any consideration of the appropriate timing of implementation of a reserve service market. On the other hand, the detailed development and implementation of such a market will take time and early commitment to the concept would be required to be operating in advance of any expectation or risk of material problems under current arrangements.

AEMC Rule Changes

The ESB is working closely with the AEMC, which is currently considering two rule change requests (received from Infigen Energy and Delta Electricity) that propose two different reserve service options to address issues related to variability and uncertainty in the NEM. The AEMC published a directions paper on these two rule change requests in January 2021. The AEMC's directions paper:

- outlined the power system need for operating reserves and the materiality of the need for a new operating reserve product as the power system transforms.
- discussed the ability of a new product to support investment in flexible capacity, and
- set out the high-level design parameters of four possible reserve service product options.

We expect the AEMC will make a draft determination on the reserve services rule change requests in June 2021.

The AEMC received 23 submissions to the Reserve services in the NEM directions paper. Feedback is summarised below.

Nature of the issue and whether a reserve service is needed to address it

The AEMC considered the main issue which may be addressed by a reserve service is an increased risk of insufficient in-market reserves being available to meet unexpected changes in net demand. These unexpected changes are driven by forecast uncertainty and net demand variability as the penetration of VRE generation increases.

Stakeholders largely agreed with the characterisation of the issue that reserves may be required to address such unexpected changes in net demand and would not be required to address expected changes in net demand. Stakeholder views differed considerably on whether these issues are material enough to warrant implementing a new reserve service market, and with respect to the urgency of implementing a such a service. A range of stakeholders also considered further work is required to determine the need for a new reserve service, and to be confident that the benefits outweigh the costs.

Options to address the issues

The AEMC presented a range of incremental improvements to address the issues on the power system or complement a new reserve service. These included improving accuracy of net demand forecasts, publishing better information, pursuing market/system enhancements, integrating DER and adapting system definitions. All stakeholders were at least somewhat supportive of the incremental improvements proposed. Many stakeholders considered these should be pursued as part of 'business as usual' regulatory reform processes. Some stakeholders suggested these reforms may be sufficient to address the issues, while others considered that the implementation of these incremental reforms will not address the issues without also implementing a new reserve service.

The AEMC also presented four reserve service market design options, including integrated and separate markets which procured reserve capacity over varying timescales. The majority of stakeholders were reluctant to commit to supporting a particular option, however several stakeholders specifically did not support the option of a ramping commitment market.

Stakeholders instead commented on preferable design options and considerations for an operating reserve service. Co-optimisation of reserves with energy and FCAS was favoured by most stakeholders. Stakeholders held mixed views on the appropriate timescale for procuring reserves, ranging from 5-, to 10-minutes and 30-minutes. A number of stakeholders considered further detail on the options is needed before their relative merits could be commented on.

The AEMC's directions paper on the reserve services rule changes concluded that a new reserve service may be needed to address unexpected changes in net demand. That is, changes in net demand that were not forecast and therefore were not expected by market participants.

The critical principle upon which to determine whether and when a new reserve service should be implemented to address these issues is that the benefits to consumers of implementation should outweigh the costs, over the long term. Stakeholders clearly hold diverging views on whether the benefits would outweigh the costs at this time, and on what the potential costs may be. Further work to explore the balance of benefit and cost will be developed for the ESB June Paper and AEMC Draft Determination.

Questions for consultation

19. In what circumstances would a reserve service be beneficial for consumers?

3. Integration of Distributed Energy Resources and Demand Side Participation

This section sets out the ESB's proposed framework for a Maturity Plan. This plan will provide a process for industry collaboration on issues to support the effective integration of DER.

This document describes the:

- Maturity Plan framework and intended processes to be used to coordinate activities
- Elements for each Maturity Plan release
- First release and engagement plan

3.1. Maturity Plan Framework

What is a Maturity Plan and why is it needed?

At a basic level, a Maturity Plan is akin to an Egg Timer. Maturity Plans are a concept used in ICT, manufacturing, and quality processes, used to help assess levels of readiness and coordination, and to provide a timetable for uplift of capabilities. A set of priority issues are identified to be worked through over a defined period of time (e.g., 6-months). At the end of that period, the 'egg timer' is tipped over and the cycle starts again to consider the next set of priority issues identified.

The Maturity Plan would introduce a 'co-design framework' that supports bringing multiple stakeholder interests together. Stakeholder input could inform consideration of strategic design questions, enabling coordination of decisions to be made through ESB and market bodies on a regular 6-monthly basis.

The intention of implementing a Maturity Plan is to provide a coordinated process to collaboratively examine strategic issues associated with the integration of DER. These issues have impacts across a range of factors including technical, market, regulatory, digital, communications and across the various dimensions of consumer experience. Considering these issues together will support taking a broad assessment of the potential solutions, on associated costs, and the value that can be unlocked for consumers. Enabling issues to be considered on an end-to-end basis will support decisions on appropriate system architecture and associated roles and responsibilities.

There has been significant effort across industry organisations, consumers and market bodies (including from CSIRO and ENA) to consider DER related issues. However, the pace of change continuing across the sector and, in particular, the continued rapid uptake of small scale DER at household level, highlights the need for clear processes and timing for decision making, and greater coordination across the sector.

The ESB intends the Maturity Plan to be a vehicle to leverage and coordinate these efforts, including alignment with activities in the Distribution Energy Integration Plan (DEIP)[17] and the Energy Consumers Australia (ECA) customer experience and service design workshops. The Maturity Plan framework is intended to enable insights to be shared and to inform cohesive decision making and adjacent regulatory processes, giving greater clarity to parties making investment decisions, and to unlock the value and benefits of integrated DER for consumers in a staged but timely manner. With regular

[17] https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/

engagement, feedback and reporting cycles, the plan is intended to support transparency and collaboration regarding priority issues for the coming 12 months.

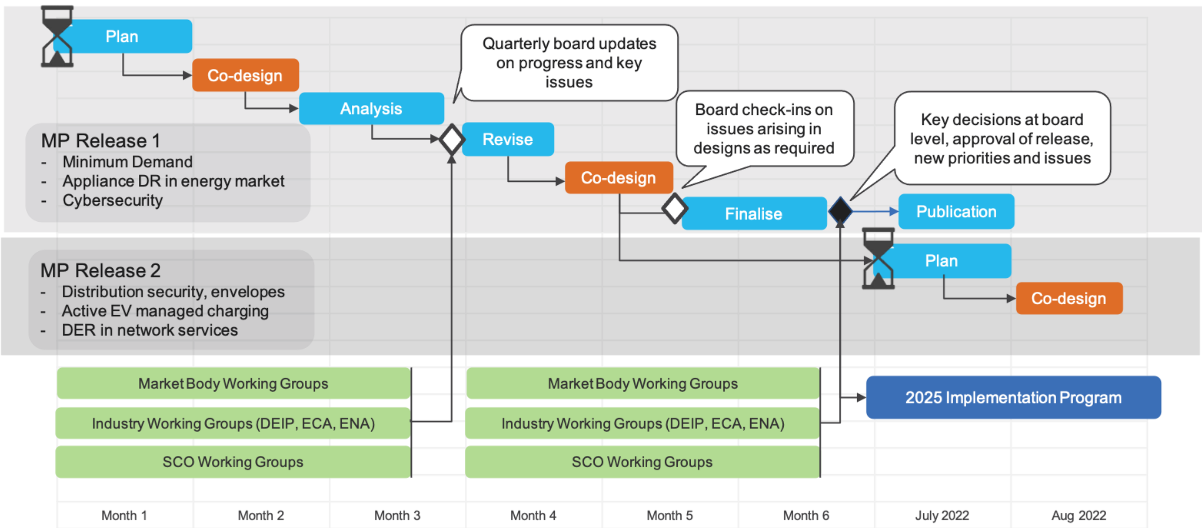
What is the basic Maturity Plan framework and process?
The framework would bring a range of stakeholder interests together (including user advocates, networks, technology providers, retailers, government and market bodies) to consider priority issues in a series of iterative co-design sprints. This is intended to ensure a strong fit and alignment with customer needs, identifying risks, where protections need to evolve and where complimentary measures may be needed.

A suite of design issues to be considered as part of the Maturity Plan are to be set out by the ESB and market bodies. The priority issues for the first release are detailed below. Issues and proposed use cases have been mapped out to provide indicative timing of a forward plan, with flexibility to adapt priorities to the changing needs of the system and sector across each 6-monthly release cycle.

The framework would involve engagement four times a year, over a 2-week window of iterative co-design workshops. At the end of each release cycle, directions are made by the ESB on core decisions relating to each issue. At that stage, the 'egg timer' flips over and the cycle starts again focussed on the priority issues for the next release of the plan.

This process is illustrated below in Figure 13.

Figure 13 Maturity Plan Process



Governance and decision making for the Maturity Plan

In this section, we set out how decisions relating to the Maturity Plan will be made and by which parties.

Firstly, it is important to clarify what the Maturity Plan will not do. The Maturity Plan framework will not replace existing governance processes, e.g., rule changes will continue to be raised with and considered by the Australian Energy Market Commission (AEMC), and regulatory approvals or decisions on technical standards will be considered by the appropriate existing bodies including the Australian Energy Regulator (AER) or the Australian Energy Market Operator (AEMO).

Participation by market bodies as part of the Maturity Plan will enable insights that emerge from the co-design process to inform consideration of rule changes or decisions going through adjacent regulatory processes. For example, where detailed analysis is undertaken to support consideration of issues as part of the Maturity Plan, insights can be provided to and considered by the market bodies to support their work on related matters.

Where potential solutions to issues emerge from within the Maturity Plan process, these could be raised as rule change proposals by participating parties. Any such proposals would be considered by the AEMC consistent with existing rule change processes.

Who will determine the publication of Maturity Plan releases?

The Maturity Plan is intended to enable a coordinated process for stakeholders to work together to consider priority issues together, consistent with each 6-monthly release.

The first release of the Maturity Plan will be issued by the ESB with input from market bodies (AEMC, AEMO, AER) by June 2021. The supporting governance and decision-making arrangements will sit with the ESB and the market bodies for the immediate future.

It is intended that the Maturity Plan framework provides an ongoing vehicle to coordinate consideration of issues required to support effective DER integration by the market bodies and stakeholders. The scale of changes required to support effective integration of DER mean the issues outlined will form the basis of a three-year workplan to develop and deliver the full detailed requirements of reform. This timeframe goes beyond the currently agreed life of the ESB.

Decisions regarding future governance arrangements relating to the ESB, are currently being considered by Energy Ministers.

How will priority issues for the Maturity Plan be determined?

Issues identified as priorities for the first Maturity Plan release have been identified as areas for immediate reform, as outlined for consultation in Part A. Future priority issues will be informed by stakeholder input via the Maturity Plan process and agreed by the ESB and market bodies closer to commencement.

Factors informing the priority of issues to be considered as part of the Maturity Plan include:

- Pressing system wide issues that require a high level of coordination (e.g., falling system minimum demand)
- The pace and scale of uptake of DER, and implications for customers and the wider system
- The emergence and pace of uptake of products and services (both within the energy market and in energy adjacencies, e.g., electric vehicles), and associated risks / opportunities for consumers and the system
- The emergence and pace of digitisation to manage costs and risks
- Trends highlighted as part of market body reporting (e.g., Integrated System Plan, Health of the NEM reports)

As set out in Figure 1, the Maturity Plan provides a quarterly cadence of reporting and decision-making sessions with ESB and market bodies on identified priority issues, informed by stakeholder input.

Potential solutions emerging from the co-design process will be presented to the ESB Board and market bodies for feedback to enable decision making at two key points over the 6-monthly cycle.

Subsequent releases of each Maturity Plan will report on progress and issues arising from the previous cycle. Each release of the Maturity Plan will identify (and update as needed):

- priorities for future releases
- consumer and industry stakeholder feedback on the issues being addressed
- decisions or recommendations made regarding priority issues considered
- confirmation of where solutions may be taken forward in adjacent regulatory processes
- highlight the implications of relevant rule changes or regulatory processes that are either in progress, under development or are planned reforms identified as part of the Post-2025 Market Design Program
- highlight issues that may be outside of regulatory remit of market bodies, but may have implications for effective integration of DER.

Elements for each Maturity Plan release

In this section, we set the following:

- What is the scope of issues to be considered as part of the Maturity Plan?
- How will use cases be included in the assessment of each issue?
- How will consideration of customer protections be built into the Maturity Plan process?

What is the scope of issues to be considered as part of the Maturity Plan?
Beyond the Post-2025 program, there have been a number of critical issues that require further exploration with industry and consumer representatives. To enable issues to be considered from the role and perspective of the customer, a set of use cases will be employed so that the co-design process takes an end-to-end view incorporating consideration of consumer experiences, protections, regulations, standards, rule changes, and an economic case for reforms. Customer protections will be considered as part of assessing risks and opportunities emerging from each issue.

The table below sets out these issues and associated use cases, and their indicative timings based on current priorities. Whilst the priority issues for the first release (R1) have been set, the remainder are subject to change, and should reflect the priorities of the ESB and market bodies (informed by stakeholder input) nearer to the commencement date.

	R1	R2	R3	R4	R5	R6
Minimum demand						
• Emergency backstops	X					
• Active solar in energy market	X					
• Active solar with system constraint	X					
• C&I Turn-up load / WDR			X		X	
• EV turn-up load / shifting			X		X	

Residential appliance participation						
• SGA market participation	X					
• Active DER LV constraints with communication standards (2030.5)	X					
• SGA market participation with cybersecurity considerations		X	X			
DER participation in network services						
• DER responses to advanced tariff structures		X				
• Direct procurement for network capacity		X				
• Direct procurement for voltage services					X	
• Direct procurement for reliability						X
Distribution security for solar PV						
• Residential dynamic limits for solar PV		X				
• C&I trading with dynamic limits for solar PV		X				
Distribution security for DER (storage, EVs, devices)						
• Residential DER trading with dynamic limits			X	X		
• DER import limits (EVs)				X	X	
DER participation new ESS / RAMS markets						
• DER in Fast Frequency Markets			X			
• DER in Operational Reserves				X		
DER participation existing ESS / RAMS						
• DER in RERT				X		
• DER in RRO					X	
DER participation in local energy services						
• Community Storage services				X		
• Local energy matching / trading						X

How will use cases be included in the assessment of each issue?

There are many factors that impact on the effective integration of DER into a future two-sided market. To reduce complexity, each release of the Maturity Plan will focus on a small subset of 'use cases' (reflecting immediate system, market and consumer needs).

A use case approach enables big problems to be tackled in smaller steps. The key benefits of the use case technique are to:

- break the problem into discrete parts that can be tackled in sequence, each of which can be deployed to bring value to customers
- expose interactions between numerous actors and technical platforms, surfacing where systemic complexity exists early in the process
- support rapid and multi-pass engagement in each release of the process
- enable consumers and their representatives to be co-designers of potential solutions, and

- adopt a customer centric language and persona that ensures that the solution does not become too theoretical. Issues can instead be explained in everyday language that all parties can work with.

Selection of use cases to be prioritised is a decision taken by the ESB, informed by stakeholder input, taking into account the following as part of its consideration:

- The relevance of specific use cases at resolving issues present in the market
- Milestones or changing conditions opening up new value streams that flow back to customers
- The potential for harm to customers, and the evolving need for associated protections
- Use cases that highlight, in practical terms, how proposed reforms to the system would provide value back to customers and participants
- Feedback and input from customers and industry stakeholders.

Consumer experiences informing use cases

Recent design thinking workshops with consumer advocates, hosted by ECA, have provided useful insights into how consumers may benefit by having their appliances and solar panels automated, while also addressing minimum demand.

Insights gained from this experience included the importance of customer consent and education in providing other authority to manage assets, the important of consumer engagement and involvement when designing products, communications and services for the new energy future, and the need for changes to be made in graduated steps.

These insights provide a good example for how issues might affect different types of customers as part of the use case creation and testing.

How will consideration of customer protections be built into the Maturity Plan process?

As part of the Post-2025 Market Design program, a risk assessment tool has been developed by the AEMC, informed by customer advocates and stakeholders. This framework is intended to help assess the benefits and risks or potential harms to energy customers from new or emerging products or services. The Maturity Plan framework will not develop such products or services, but consideration of a range of tangible use cases will help to inform where potential benefits and risk or harms may exist for customers.

This risk assessment tool will operate in parallel and be used to support consideration of issues more broadly than those being considered in the Maturity Plan. Insights emerging from the Maturity Plan framework will be taken forward and considered as they arise.

Consideration of potential risks, opportunities and need for customer protections that address these will therefore be integrated within each release and co-design cycle of the Maturity Plan.

Maturity Plan - Priorities for first release (R1)
The ESB will progress the following issues for the first release of the Maturity Plan.

- Minimum Demand
    - Emergency backstop

    - Passive to Active solar PV, responsive to market signals
    - Active solar PV as market responsive by retailers and/or aggregators
    - Consumer protections and risks with new participation models
- DER Participation
    - Appliance based demand response (residential)
    - Cybersecurity, technical and interoperability standards
    - Consumer protections and risks with new participation models

For releases beyond R1, the finalized priorities for the following release of the plan will be informed by stakeholder input and feedback through the engagement plan and confirmed through the decision-making process at the end of each release cycle. This will enable the most up-to-date issues and priorities to be reflected and considered in each release of the Plan.

The ESB seeks feedback on the detail set out in this section.

Questions for consultation

20. What are stakeholder views on the proposed maturity plan approach and priorities identified for the first release?

Consultation and engagement in Maturity Plan activities

Reflecting the urgency of many of the priority issues, the ESB will continue to progress consideration of issues highlighted consistent with the process outlined above.

To support stakeholders in resource planning, the ESB has set out high level timing for co-design and engagement, commencing in April 2021. The ESB anticipates there will be a mix of stakeholders with consumer, network, technology provider, retailer, market bodies or government interests to participate in co-design sprints alongside market body representatives. Interested parties will be able to register their interest to participate in the co-design sprints, noting that the mix of stakeholders involved may change depending on the issues for consideration.

3.2. Consumer Protections – Risk Assessment Tool

The draft consumer risk assessment tool builds on the guiding principles proposed by the ESB in its January Directions paper, which are set out below. These principles do not replace the core principles of the existing consumer protection framework but guide the development of consumer outcomes and protections in the future market.

Access to energy	Recognising that energy is an essential service, customers should have access to at least one source of electricity
Switching providers	Customers should be able to change retail providers if and when they choose
Access to information	Customers should have access to information that is sufficient, accurate, timely, and minimises complexity and confusion to allow them to make informed decisions
Vulnerable consumers	The needs and circumstance of vulnerable consumers will need to be explicitly considered
Dispute resolution	Customers should have easy access to low cost dispute resolution mechanisms for when things go wrong.

Overview of the consumer risk assessment tool:

Context: The risk assessment tool acknowledges the existing consumer protection frameworks that apply to customers in the NEM and how the changing market could pressure them to require amendments or complementary measures.

Benefits and risk identification: Inspired by Catapult Energy Systems,[18] a "benefits first" focus has been incorporated. We consider that consumer benefits should be front of mind when considering market design to help facilitate a better energy environment for consumers and innovation. The tool's risk identification component seeks to identify aspects of the new market that could expose consumers to harms requiring protection through a series of questions. The use-cases described above is an approach to help flesh out both further benefits and identify changes in the market that may expose consumers to harms and vulnerabilities.

Evaluation: In evaluating the risks, it will be important for market bodies to understand the limitations on how they can influence consumer protections in the market. Adopting clear circles of influence will contribute to constructive and reasonable recommendations on how the market bodies could treat future risks. The circles of influence areas:

- **Act:** consequences that are within the control of the NECF and therefore, the energy market bodies.

[18] Catapult Energy Systems, *Smarter Consumer Protection Manual,* December 2019, available at: https://es.catapult.org.uk/brochures/smart-consumer-protection-manual/

- **Influence:** consequences that are not controlled by the NECF but are controlled by other regulatory bodies, either such as the ACCC or regulatory bodies within jurisdictions. In these cases, the ESB will make recommendations for complementary measures to be adopted by these agencies to protect consumers.
- **Monitor:** consequences entirely beyond the scope and control of energy policy that could affect energy consumers and require ongoing understanding and monitoring.

Careful evaluation can assist to avoid over-regulation where benefits and risks are viewed on a scale. As such, it is proposed that this part of the risk assessment tool considers the risks' cause, affect, and magnitude. This can assist market bodies determine if a risk disproportionately affects one type of consumer or is unlikely to have a significant impact on the market or on consumers.

Treatment of risks: Treatment of risk is where consumer protection actions take place. This could include direct actions from market bodies including through rule changes and changes to guidelines and procedures and complementary measures. These approaches would be considered after risks have been understood and assessed through collaboration with stakeholders. Risk treatments would only be accelerated if an urgent and large risk was identified.

Communicating and consultation: This risk assessment tool will be a way to continue to communicate and consult with stakeholders and consumers on ways to protect consumers in the two-sided market through future rule change requests and reviews and the Maturity Plan. As new issues arise in the market, we encourage stakeholders to share these experiences with market bodies or submit a rule change where necessary.

Monitoring and reviewing the treatment: The risk assessment tool will be used over the long term to reassess treatment and determine if or when further changes may be necessary.

Consumer Risk Assessment Tool

Context

The foundation of the national electricity market's energy consumer protections framework is the Australian Consumer Law (ACL), National Electricity Consumer Framework (NECF) and Victorian Energy Retail Code (Victorian Retail Code). As more consumers have two-way energy flows as they move to DER, and digitalisation and better data is increasing control and communication options, we need to consider what protections are needed to ensure customers are able to trust the new business models and not bear unreasonable risks. The ESB is considering consumer protections in the context of the broader consumer experience under the two-sided market, including testing the benefits and risks through the use cases as part of the ESB Maturity Plan.

Communicate and Consult

Benefits Assessment

Identify the benefits

- What does the new service/innovation allow the consumer to do that they couldn't do before?
- How are these impacts likely to change as the future energy system changes? Will these benefits only be realised in the future?
- What evidence is there that consumers want this? And whether it solves any problems they are currently facing?

Map out how the service/innovation is being delivered to consumers

- HOW will they know about this impact?
- WHEN will you tell consumers about these benefits?
- WHO will it come from?
- WHERE will they get this information from?

Identify Risks

- What could this innovation mean for consumers, considering the multiple aspects of consumer experiences and situations.
- How could this be a positive, easy process for the consumer?
- What would this service or innovation mean for personal and sensitive data held about the consumers?

Evaluate

Evaluate the treatment opportunities of the risk

- **Act**: consequences that are within the scope of the NECF and therefore the energy market bodies
- **Influence**: consequences that are not covered by the NECF but are controlled by other regulatory bodies such as the ACCC or jurisdictions. In these cases the ESB will make recommendations for complementary measures to be adopted by these agencies to protect consumers.
- **Monitor**: consequences completely beyond the scope and control energy policy that could affect energy consumers and so require ongoing understanding and monitoring.

Evaluate the impact of the risk

- **Cause**: what is causing the risk?
- **Affect**: which consumers are affected most and how are they affected?
- **Magnitude**: how much of a risk does it pose to consumers?

Treat risk

What options for treatment exist?

- Are treatments required in addition to the existing consumer protection framework (the NECF, ACL, and Victorian Retail Code)?

Who is responsible?

- Who will implement treatment plans (energy market bodies, rule change, guidance change, jurisdictions, etc.)?
- What are the avenues for recourse (civil penalties etc.)?

Re-analyse risk after treatment

Monitor and review

3.3. Flexible Trading Arrangements

This section provides a detailed overview of the two flexible trading arrangements, including the benefits and issues identified so far by the ESB. Allowing more flexibility in the trading arrangements and those that currently exist will facilitate new business models to develop. These models should provide customers with an interface and access to improved choice, revenue streams and cost savings via greater access to the spot and service markets.

In general, the ESB considers that Model 1 is likely to have low implementation costs. It is building off an existing framework, and the main changes are already occurring in current rule change processes (which incorporate consideration of costs and benefits).[19] This may limit the need for a further cost-benefit analysis at this stage. The ESB is continuing to refine the design of Model 2 and based on feedback, will consider the case for and materiality of changes to market and industry systems to facilitate this model.

The ESB is not considering the previously proposed Multiple Trading Relationship (MTR) changes at this stage.[20] Changes to the Small Generation Aggregator (SGA) framework facilitate a similar outcome and leverage the existing market structure without incurring the significant upfront and ongoing system-wide costs, borne by DER and non-DER customers alike, associated with the proposed MTR design.[21] These significant costs, principally due to retailer and Local Network Service Provider (LNSP) system changes, would be avoided as the SGA framework is already in place and used today. This means the models outlined below would have limited system implementation costs and upfront costs would only be borne by those market participants who can identify opportunities to shape business models using this framework.

Flexible trader model 1 – MSGA+ (Second connection point)

This model seeks to provide more flexibility for the second connection point option. It is essentially an extension of the existing SGA framework, from generation only, to cater for bi-directional energy flows. This essentially means storage and EV chargers, for example, added to generation. The consumer's use/ production of energy services at a single site would be separated into two connections, one or both of which may be bi-directional, via two metering installations and NMIs (consistent with the current SGA model). Doing so enables the NMIs to be treated independently (e.g., for consumer protections, Metering Coordinator appointment, billing, network charging, etc.). The end-user could engage different traders at each connection point.

In accordance with the current requirements of the NECF, to the extent either trader sells electricity to a small customer, that trader would need to be an authorised retailer, unless exempted by the AER and comply with all applicable consumer protection provisions.[22]

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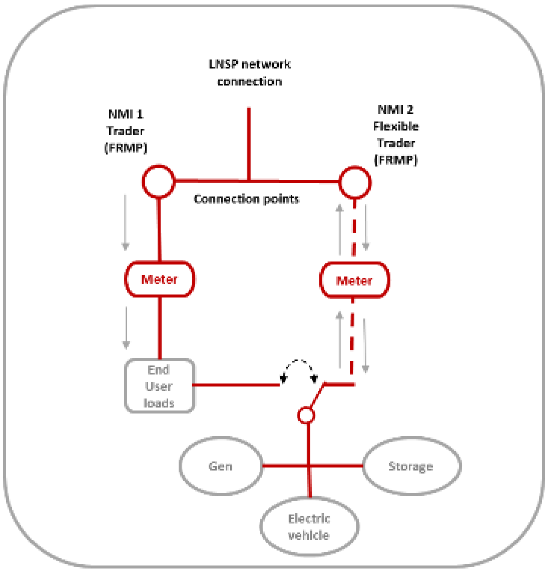
[19] Please see https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

[20] As considered by the AEMC in 2014-15.

21 Jacobs SKM completed a cost benefit assessment of the previously proposed MTR design which estimated total costs in the order of hundreds of millions across retailers, DNSPs and AEMO over an extended time period. This can be seen here https://www.aemc.gov.au/sites/default/files/content/acc6652a-7566-464e-9512-e77e10bcd82a/AEMO-rule-change-proposal.pdf.

22 The AER may also need to consider how the current exemption from retailer authorisation framework might apply. For both models, the AER may not consider exemption from retailer authorisation required – sale of electricity for EV charging in some cases as an example.

The end-user could switch their load and generation between the two connection points, as illustrated in the diagram below.



As identified by Energeia's expert advice to the ESB/AEMC,[23] the upfront cost of establishing a second connection point can pose a material barrier to the use of this model by participants, particularly when retrofitting existing sites. Energeia identified numerous variables and complexities that can considerably increase installation costs, such as upgrading network connections or replacing old metering infrastructure. This limits the use of this framework to sites with high potential value or when the additional costs can be reduced such as for new builds (e.g., new residential home developments) when the additional cost of installing a second connection point is minimal. The ESB considers, however, that the majority of these implementation costs would be borne by the parties choosing to use this model, not spread across all customers or market participants. Parties considering whether to use this model can assess whether it is appropriate for them, given the costs and benefits in their particular application. Second connection points will not be mandated.

The AEMC's Integrating Storage rule change is considering rule amendments to facilitate this model, to an extent.[24] This rule change considers allowing a single registration category to have bi-directional flows, i.e., storage, and provide ancillary services. The AEMC is considering whether this should be done through the existing SGA category or through a new participant category, which could eventually be a universal participant category.

Benefits

An enhanced SGA framework would reduce barriers to entry for aggregators that can harness DER assets as they develop to better participate in the market. This would allow the aggregator to act as a third party who can participate in the wholesale market or provide network support on behalf of small customers with EV chargers, batteries or other controllable devices.

A customer would be able to maximise the return on investment from their DER, e.g., an EV charger, by enabling real-time arbitrage across two retail plans while also allowing the customer to choose to

[23] https://esb-post2025-market-design.aemc.gov.au/32572/1611022920-enegeia-expert-advice-on-the-cost-of-establishing-a-second-connection-point-v2.pdf

[24] Please see https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

use their DER system as a gross or net generator. Enabling energy arbitrage between two retail tariffs would increase retail competition and could be a catalyst for increased retail price innovation among existing retailers.

These changes would also enable different end-users at each connection point or NMI. For example, this could be useful for landlord and tenants in long-term lease arrangements for the installation of generation plus storage.

Issues

There are additional issues on which the ESB would like stakeholder input. This includes the key areas, identified by Energeia, where customers seeking to install a second connection point at a premise could encounter a barrier outlined in the below table.

Issue	Barrier
Network policy	Currently, processes for installing a second connection point differ widely across the NEM. Some distributors do not allow the installation of a second connection point to a small customer's premises for sub-loads or embedded generation, even though the rules do not prohibit this.
Timeliness	The process timeline for a second connection is not controlled by any one party and is a multi-step process with multiple opportunities for delay.
Tariffs	Currently, each NMI is assigned a tariff with a network access charge, meaning a customer with multiple connection points to the grid would have to pay multiple access charges. Potential costs of this are outlined below. Additionally, distributors may also have concerns around how to allocate network costs efficiently between multiple connection points. For example, end-users may avoid demand-based charges (where they are required to be applied) by splitting loads across two connection points.
Upfront costs	Energeia estimated that for a basic new second connection, the average small customer will pay an upfront cost ranging from \$650-\$3,260. The key drivers of final cost paid by the customer are whether a new service wire is required and what type, whether a switchboard, meter box and/or main fuse (i.e., meter board) upgrade is required, and whether the existing connection needs to be de-energised.
Ongoing costs	Energeia determined through researching pricing proposals and discussions with distributors that customers would likely incur additional tariff charges associated with a second connection point. On average across the distribution networks, Energeia estimates that a small customer would be charged \$371 annually for the additional connection point, including network and retailer charges.

Flexible trader model 2 – Sub-meter connection point

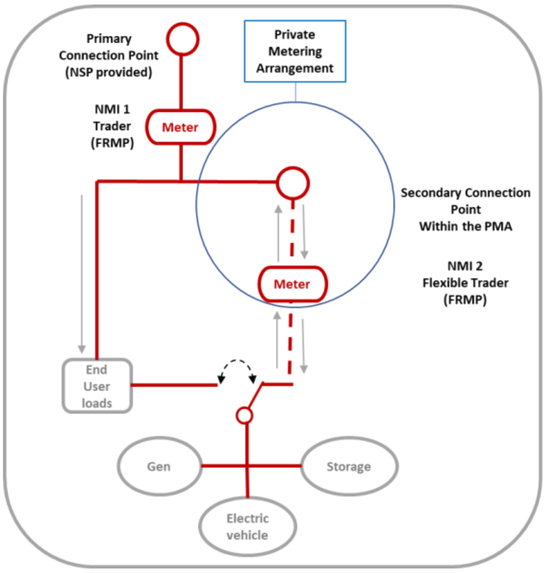
The ESB is considering an additional flexible trader model given the risk that the cost of establishing a second connection point, network tariffs and distributor policies are material barriers to uptake of model 1, that are not easily addressed.

This model provides a specific category of connection arrangement, a Private Metering Arrangement (PMA). The ESB is further developing this framework but considers that it might be based on new NER provisions that establish an appropriately accredited party's ability to establish a sub-metering connection point arrangement (without it being considered under the Embedded Network framework), with technical requirements and safeguards determined in subordinate procedures.

This model could remove or reduce many of the barriers to uptake of the flexible trader model 1. For example, this model could enable a simple additional sub-meter installed concurrently with a new solar, battery or EV charger installation without additional involvement from the distributor or need to upgrade existing electrical infrastructure over and above what would have otherwise been required.

Over time, the PMA requirements could provide a flexible framework for the adoption of non-traditional types of metering installation and meter location, provided that device, installation and maintenance standards can be maintained. For example, a metering installation attached to, and as a component of, a battery and rooftop solar system.

This reform would likely take a longer time to implement than the flexible trader model 1. It would require a new rule change process to implement. The ESB welcomes stakeholder feedback on whether this reform could increase participation, to inform recommendations on timing.



Benefits

The PMA second connection point configuration potentially creates a more advantageous position for the end-user than model 1 as distributor involvement would be removed. The provision and maintenance of the PMA connection point is open to competition. Netting the energy flows between the two connection points would reduce energy-related network charges. Due to the competitive nature of the PMA establishment, it might be more cost-effective than a connection managed by the distributor in relation to the establishment and ongoing costs.

It may be the case that, as for model 1, current retail market processes such as customer switching, meter churn and metering role appointments do not need to be materially altered. This model also ensures that all energy withdrawn or injected into the distributor's network at the site is measured at a single point, removing the risk of an end-user splitting connection points to avoid demand charging and the like.

Issues

A key issue with this model is who should provide the NMI given the secondary connection point is not to the distribution or transmission network. The NER would need to allow a private network manager (or similar) to create NMIs for the metering/private network. The NER would also need to specify who is responsible for NMI creation and define the PMA, with AEMO procedures and processes dealing with the technicalities and approvals (e.g., metering design/configuration approval through metering party accreditation processes). Requirements developed in the rules or procedures would need to provide assurance that the establishment of a PMA would involve the accurate linking of connection points to establish the necessary subtractive process for accurate wholesale settlement.

Another issue is how network charges would be reconciled across both connection points between the two traders. The retailer at NMI 1 must deal with network charges that will not correlate to the wholesale energy attributed to their connection point (this is because the LNSP will base their charges on the flows of energy at the primary connection point rather than the adjusted flows for the retailer at the primary connection point once the NMI 2 energy flows have been deducted). This will require the retailer at the primary connection point to be provided with NMI 2 metering data so that they can reconcile (note that this is the current market practice where subtractive metering arrangements exist). This is the same mechanism that comes into effect where a connection point in a retailer's portfolio becomes a parent connection point for an embedded network.

This model ensures that all energy withdrawn or injected into the LNSP's network is measured at a single point, removing the risk of an end-user splitting connection points to avoid demand charges. Energy flows beyond the LNSP's point of isolation should not impact the LNSP's ability to provide accurate and verifiable network charges. The metering configuration for NMI 2 will need to be specified and the authorisation of wiring connection for energy plant (i.e., generation/storage) should be considered in technical procedures within the NER framework.

Disconnection rights and impacts for NMI 2 could require further consideration. NMI 2 could (if necessary) be de-energised or de-activated by the relevant trader without affecting the primary connection point trader (retailer) and connection point, or the end user's ability to use their storage and generation via NMI 1. If the primary connection point were de-energised, this would de-energise NMI 2 by default (and similarly if exports from the primary connection point were constrained), and arrangements may be needed to provide notice to the relevant trader in this case, contractually or under the rules.

This model is different from an Embedded Network (EN) as the EN framework primarily supports a private electricity network with multiple end-users, not a single user with separate trading relationships.

Questions for consultation

21. Do stakeholders have any feedback on the approach for developing the trader-services model pathway?

22. What technical and regulatory barriers, challenges and opportunities may Model 2 present to Traders, end-users and distributors? What challenges would be present for metering services in either model?
23. How might the designs be improved to accommodate and facilitate greater trading of non-energy services from either model?
24. What are the benefits and risks of enabling arbitrage between separate connection points? If there are risks, including for retailer and network tariffs, how should they be mitigated?
25. Do stakeholders consider there to be high implementation costs for any of these options? If so, would these costs be borne by all system users or predominantly by the party choosing to enter the flexible arrangement?
26. Are there other options the ESB could consider on the path to support more flexible trading for end-users?

3.4. Scheduled Lite

In balancing supply and demand across the electricity grid, the system operator relies on visibility of the intentions and availability of resources, ahead of and in real time, as well being able to adequately forecast demand and the outputs of wind and solar generators. This becomes increasingly challenging in the context of higher proportions of variable and non-scheduled generation responding to wholesale market prices combined with increasing numbers of customer-side relays that can switch devices on and off.

As more customer-side resources and other non-scheduled resources respond to price signals in the NEM, it becomes increasingly important their intentions are accounted for in those calculations. In providing ways for market participants aggregating customer-side appliances and devices and other large customers to provide information to the market, it may also provide access to additional value streams. For example, non-scheduled customers cannot participate in services that require a level of participation in centralised scheduling.

The ESB is investigating changes to enable more service providers to participate in the wholesale market to obtain the best outcomes for customers and the efficiency of the market more broadly. In doing this, the ESB is mindful the status quo (i.e., no change) could have adverse consequences. This includes difficulties in being able to securely integrate more resources into the NEM, which could limit choices for customers who own, or want to own these resources, and may also limit the benefits that customer-side participation could deliver to the market. For instance, without adequate visibility of the availability and intentions of growing demand response, very high and low prices may be managed in ways that are less efficient. This could include committing fast-start generators to respond to forecast high prices or more frequent use of out-of-market interventions, the costs of which are passed onto customers.

What is scheduled lite?

Scheduled lite is a proposal to enable small to medium sized resources (including demand and generation) to actively participate in market processes or dispatch as the current scheduling processes can be complex and onerous to interact with.

Scheduled lite aims to facilitate the further penetration and active participation of DER, flexible demand and renewable energy by opening up opportunities to engage in market services, while giving greater visibility and certainty to the system operator to assist in the efficient and secure operation of the system.

Scheduled lite could form the foundations for enabling greater customer side participation in the NEM in the long-term, beyond 2025. Any proposed model would be voluntary, allowing for participants to decide whether it would be in their best interests to sign up for scheduled lite. The ESB would only consider a transition to a more obligatory approach in the future if:

- operational inefficiencies caused by a lack of visibility accelerated faster than voluntary measures could adequately address; or
- a voluntary system was not able to achieve a balance of obligations and incentives that could deliver value in the long-term interests of consumers.

Objective for scheduled lite

Beyond the high-level purpose of enabling greater participation in market processes or dispatch, the exploration of scheduled lite seeks to achieve a set of specific objectives that are linked to tangible benefits for the market and are in the long-term interests of consumers. The proposed objectives for scheduled lite are to:

1. **Create a framework to encourage greater participation of responsive resources** – Additional resources visible to the market and available in scheduling and dispatch and potentially providing system services should lead to reduced wholesale electricity prices and lower system service costs for all consumers. The framework also enables end users that have invested in responsive resources to be rewarded for their responsive characteristics of their devices.
2. **Improve the efficiency of dispatch outcomes** – If there are material resources that are responding to price or unexpectedly changing their behaviour moments prior to dispatch in a manner not visible to the system operator or participants, this may lead to over or under dispatching of generation. If scheduled lite can provide additional information on likely behaviour or intentions, then this could improve dispatch outcomes and reduce costs to all consumers.
3. **Improve the efficiency of forecasting and scheduling outcomes** – Additional information on likely behaviour and intentions may also improve the efficiency of forecasting for the system operator as well as more efficient scheduling of resources. This could lead to more informed decision making for participants, with the potential to reduce costs. Enhanced visibility may also benefit networks in their management of congestion, operating envelopes and planned and unplanned network outages.

Any obligations from participating in scheduled lite would apply to market participants and would not require consumers to directly interact with the market. The impact on consumers would be established through contractual arrangements with their Financially Responsible Market Participant, in the same way that most end users currently interact with the market (i.e., similar to consumers' arrangements with their retailer).

Separately, the AEMC is assessing a rule change proposal to classify generators between 5 MW and 30 MW as scheduled (or semi-scheduled). Through this assessment, the AEMC is exploring the magnitude of issues caused by non-scheduled generators and will also consider the appropriateness of using scheduled lite as a possible alternative to requiring these smaller generators to be classified as semi-scheduled or fully scheduled.[25]

Question for consultation

27. Are the stated objectives appropriate? Should additional objectives be considered in the design of a 'scheduled lite' arrangement?

25 For more information on this rule change see: https://www.aemc.gov.au/rule-changes/generator-registrations-and-connections.

Principles for design

Given the stated objectives, it is beneficial to establish a set of principles to scope out and govern the detailed design of scheduled lite. These principles, described in the table below, are additional to the requirements of the NEO and are aimed at providing a framework to establish the detailed design. The ESB intends to finalise these principles subject to stakeholder feedback to support directions in the Post-2025 recommendations mid-2021.

Principle	Rationale
Applies only to non-scheduled load and generation resources	• The purpose of the proposed mechanism is to enable additional participation beyond the existing scheduling categories. • Scheduled lite is not intended as a means for existing scheduled or semi-scheduled participants to move to lighter scheduling requirements. • Scheduled lite would facilitate participation from both load and generation in line with the principles of a two-sided market.
Frameworks should enable customer choice	• The scheduled lite design should be flexible and consider the consumer experience, such that they should not be impacted adversely or required to change their behaviour • The scheduled lite design should be complemented and supported by the consumer protection framework. Further, in designing scheduled lite, consideration should be given to whether changes to the consumer protection framework are required.
Additional information required improves the efficiency of operational decisions	• The schedule lite design should not require onerous or excessive information that does not deliver value to the market operator or the broader market. • Careful consideration should be given to the importance, accuracy and granularity of information required (as well as the costs of providing it) to ensure these are proportionate to the market benefits realised.
Design must be congruent with the existing NEM design	• Any changes being considered should not undermine the existing NEM market design principles or compromise the integrity of the market. • The design should not introduce lighter measures that compromise system security or reliability or introduce incentives linked to actions unrelated to the benefits of market participation.
The benefits of more resources participating in forecasting,	• Sufficient central and market efficiency gains and benefits should be realised relative to the costs of

scheduling and dispatch must be relative to implementation and operational costs	facilitating the implementation of any new scheduling arrangement. • As a voluntary mechanism, individual participants can make their own assessment on the value proposition of using scheduled lite.
Obligations and risks should be balanced against incentives for participation	• The design should try to balance the risks and obligations with the incentives to participate in scheduled lite. • Designing scheduled lite with a view to maximise participation would contribute to the overall benefits of the reform. • The design should support appropriate cost and risk allocation.
The design should facilitate resources to offer services into new system services markets where appropriate	• The design of schedule lite should be flexible enough that when new system services are established, if appropriate, resources participating under scheduled lite should be able to access those service markets.

Question for consultation

28. Are there any additional or alternate principles that should be considered?

Overview of scheduled lite models

The ESB is seeking feedback on two possible designs — visibility and dispatchability — to better understand the materiality of: incentives to participate; market costs and benefits; efficacy of implementation; and ability to participate. These two models have different objectives and could accommodate different types of resources represented by a range of market participants, and thus are not mutually exclusive. Both designs seek consistency with the design principles above.

The models presented below set out two possible components of an evolved scheduling framework, with both models establishing the pathway for greater two-sided participation in the market.

Visibility model

Purpose: Provide additional information on the future behaviour and intentions of resources, without requiring participation in dispatch or full responsiveness.

Features:

- Non-scheduled resources (e.g., generation/demand/DER) provide self-forecasts of future behaviour or intentions.
- No telemetry requirements
- Participants incentivised to participate through reduced FCAS causer pay allocation and – if introduced – reduced operating reserve cost allocation.
- Non-financial consequences for inaccurate forecast accuracy (e.g., reputational damage).

Key benefits:

- Additional visibility for the market operator and networks to better manage the system
- More information available to improve centralised forecasting activities, which could assist in scheduling efficiency

Visibility model	Design element	Option	Change from non-scheduled
Market Access (static)	Participant type	non-scheduled load/demand aggregators/generators/VPP	Neutral
	Telemetry	Use 5-minute meter data	Neutral
	Metering	No change	Neutral
Market information (dynamic)	MT PASA	Provide no information	Neutral
	ST PASA	Provide no information	Neutral
Market intention	Pre-dispatch (energy bids)	Provide no bids	Neutral
	Forecasting generation /consumption	Provide forecast of generation/consumption	Increased
	Dispatch targets?	Not in dispatch	Neutral
Incentives	RERT costs?	RERT costs still apply	Neutral
	Civil penalties?	No change to civil penalties	Neutral
	Regulatory FCAS allocation?	Reduce regulatory FCAS causer pay allocation	Improved
	RRO obligations?	No change to RRO obligations	Neutral
	Interaction with OR	Reduce OR cost allocation	Improved

The visibility model would enable both aggregations of small end users, up to individual very large end users to offer their forecasted generation or consumption with some reward for the provision of this information. Forecasts could be updated throughout the day as more information is available, with a threshold accuracy requirement (e.g., 80% accuracy required). This model could be implemented as a new mechanism, or potentially could utilise existing market information provision processes such as the AEMO Demand Side Participant Information Portal.

Dispatchability model

Purpose: Encourage additional resources to participate directly in scheduling and potentially setting the market price, through reducing some of the barriers to participation and providing greater incentives.

Features:

- Non-scheduled resources (e.g., generation/demand/DER) provide energy market bids

- Lighter telemetry requirements for participation (i.e., SCADA light)
- Participants incentivised to participate through:
  - reduced FCAS causer pay allocation
  - avoided RERT cost allocation (for load)
  - reduced civil penalties
  - resource allocated firmness factor for RRO obligation
  - if introduced – reduced operating reserve (OR) cost allocation and potential to bid into a OR market.

Key benefits:

- Additional visibility for market participants, market operator and networks to better manage the system
- More accurate market scheduling outcomes and scheduling for participants
- Access to additional revenue streams for responsive resources

Dispatchability model	Design element	Option	Change from non-scheduled
Market Access (static)	Participant type	non-scheduled load/demand aggregators/generators/VPP	Neutral
	Telemetry	Light version of SCADA	Increased
	Metering	No change	Neutral
Market information (dynamic)	MT PASA	Not required	Neutral
	ST PASA	Provide some information	Increased
Market intention	Pre-dispatch (energy bids)	Provide standing bids	Increased
	Forecasting generation /consumption	Provided through bids, intermittent generators provide forecasts	Increased
	Following DI's	Follow DI (within limits of the resource)	Increased
Incentives	RERT costs?	Load avoids RERT	Improved
	Civil penalties?	Reduce civil penalties	Improved

	Regulatory FCAS allocation?	Reduce regulatory FCAS causer pay allocation. Ability to bid into FCAS markets.	**Improved**
	RRO obligations?	Resource rated on firmness factor for RRO obligations	**Improved**
	Interaction with OR	Reduce OR cost allocation, potential to participate in OR	**Improved**

The dispatchability model could be used by aggregators, retailers, small-scale generation as well as large consumers. It would enable responsive resources that could respond to price signals to do so, under a lighter framework than the current scheduling and semi-scheduling requirements. A benefit of this model is it could allow resources to bid into both system service markets and the wholesale market.

Question for consultation

29. Are there any additional scheduled lite models or design elements that should be considered through this process? If so, what are the purpose, key features and benefits?

Detailed design elements

The following sections provide the detailed policy design and rationale for the visibility and dispatchability scheduled lite models. These design models for scheduled lite are not mutually exclusive and the intention is to refine and adapt according to detailed analysis, insights and stakeholder feedback.

Additional participation

Both visibility and dispatchability models for scheduled lite may require information, physical infrastructure, or forecasts of intended behaviours to participate in the market. Three areas of participation requirements considered include:

- Revealing intentions (bidding and forecasting)
- Participating in dispatch (following dispatch instructions)
- Communicating behaviour (telemetry).

Revealing intentions

For a resource represented by a market participant, to participate in the market, it will need to reveal some degree of its intentions, through either bids or forecasts. The provision of this information could improve efficiency in dispatch and efficiency in scheduling and forecasting.

Currently, participants reveal their intentions to the market through several ways, including:

- **Capacity and availability information** - Semi-scheduled and scheduled generators/load provide information on their capacity and availability into the Short-Term Projected Assessment of System Adequacy (ST PASA) process. This information is used by AEMO and the market to assess and plan resource adequacy seven days prior to dispatch.

- **Daily price and quantity bids within bid bands** – semi-scheduled and scheduled generators/load place daily bids through the pre-dispatch and dispatch processes in the form of price bands for different quantities that they are willing to generate or consume at. These prices are then used in the NEM Dispatch Engine (NEMDE) to determine and dispatch which units should generate or consume for each dispatch interval. For semi-scheduled generators, AEMO centrally forecasts the solar and wind generation and uses these forecasted quantities of generation to plan the operation of the market up to dispatch.
- **Providing self-forecasts** – AEMO is currently operating some programs that enable participants to provide self-forecasts of their generation.
  - Self-forecasting program[26] — In 2018, AEMO and ARENA begun a five-minute self-forecasting program with the aim of reducing generation forecast error and providing greater autonomy to existing semi-scheduled generators. In this optional program, participants can provide five-minute dispatch self-forecasts of the unconstrained intermittent generation for use in dispatch. The program requires forecasts meet a threshold level of accuracy and participants may be able to reduce their FCAS causer pays costs.
  - VPP demonstration trial[27] — In AEMO's VPP demonstration trial there is a requirement for VPPs to provide aggregated forecasts of anticipated active power flows which provides information used by AEMO's operational forecasting team in monitoring overall balance of supply and demand.
- **Providing static information on capabilities and likely behaviour** – Market participants with demand or price response capabilities provide some information about those resources at a connection point and portfolio level to AEMO through its Demand Side Participant Information Portal.[28] The information from this portal is used by AEMO in medium-term reliability assessments and processes, including MT PASA.

Based on the experience above, there are three key dimensions when considering how participants reveal their intentions that contribute to the secure and efficient operation of the market.

- Granularity – How granular are the intentions of future behaviour?
- Frequency – How frequent does the information need to be provided and updated?
- Use – How is the information used, and what are the consequences of inaccuracies?

For example, if there is a resource that it is participating in dispatch it would need 5-minute granularity; its intentions (represented through forecasts and bids) would need to be reflective of its

26 More information on AEMO's 5 minute self-forecasting program is available here: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/participant-forecasting

27 More information on AEMO's VPP demonstration trials is available here: https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations

28 More information on AEMO's Demand side participant information portal is available here: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines/demand-side-participation-information-guidelines

capabilities with close to real time frequency; and as the information is used in dispatch the consequences of inaccurate information may be high (depending on the size of the resource).

Proposed scheduled lite design

Scheduled lite model	Proposed requirement	Rationale
Visibility	Resources would be required to provide forecast of behaviour and update if this changes.	• Resources would provide daily forecasts of consumption/generation and update throughout the day as new information becomes available. • The forecasts would be at a 5-minute granularity to enable assessment of ability to avoid FCAS causer pays costs. • As the resources using this are unlikely to impact the operational security of the market, a threshold accuracy approach could be adopted. For example, the resource would need to meet an 80 per cent accuracy threshold, and if the resource breaches that threshold without sufficient rationale, it could be removed from the scheduling category. • Resources could consider forecasting their consumption/generation themselves or could use a third-party forecaster.
Dispatchability	Resources would be required to submit bids.	• As the resource is actively participating in dispatch, it would need to provide granular, frequent bids, that reflect its intentions to trade in the market, in the same way a scheduled or semi-scheduled generator does today. This includes STPASA availability, bidding into pre-dispatch, dispatch and allowing for rebidding. • If the resource is intermittent, it could self-forecast its generation to also allow it to reduce its FCAS causer pay costs.

Question for consultation

30. Are the forecasting requirements proposed for the visibility model appropriate? Are there alternate options for granularity, frequency and use?
31. Are the bid requirements appropriate for the dispatchability model?
32. What are the barriers, if any, to self-forecasting? How far ahead of time would a resource be able to provide meaningful forecasts of their likely behaviour?
33. How appropriate is the use of threshold accuracy and non-financial penalties for inaccuracy? What are the trade-offs of using this approach?

Participation in dispatch

For a resource to actively participate in dispatch it will need to be able to receive and respond to dispatch instructions from the market operator, dictating the quantity of electricity the resource must generate or consume. Resources are required to respond to instructions within the space of a dispatch interval – five minutes. Developing the systems required for participants to receive dispatch instructions may incur additional investment costs for participants. Additionally, the need to comply with dispatch instructions involves compliance costs and failure to comply with dispatch instructions can expose a participant to non-compliance risks, such as:

- being liable to causer pays penalties from negatively impacting system frequency
- triggering dispatch instruction non-conformance rule which, among other things, prohibits any relevant unit from setting the spot price.[29]
- potentially making the participant liable for any civil penalties which might be associated with non-conformance with dispatch instructions.

All of the above requirements add significant cost and complexity to participants and can act as a significant barrier to engage with the market.

To make the scheduled lite arrangements more accessible, an option is to establish some degree of flexibility regarding conformance with dispatch instructions. While maintaining the integrity of the central dispatch process is critical for the development of any scheduled lite arrangements, there is a trade-off to be made between:

- the impacts of non-conformance with dispatch instructions, and
- the cost to the market from fewer active and price-responsive resources participating in central dispatch.

Transpower, New Zealand's system operator, offers an example of how the conformance requirements for dispatch instructions could be reduced for scheduled lite participants in its dispatch-capable load station (DCLS) market participant category.[30] See Box 2 below.

Box 2 Transpower – dispatch-capable load station example

The DCLS category is the Electricity Authority's means of providing a more suitable and convenient mechanism for improving the efficiency of the forecasting and dispatch process and encouraging greater demand side participation.

Retailers or elected third parties are able to classify loads as a DCLS, which make the retailer or third party a dispatchable load purchaser. These dispatchable load purchasers submit bids that form prices and feed into pre-dispatch schedules. The load then receives a dispatch target with compliance obligations that are more lenient than those applied to generators. These purchasers can nominate periods when they do not want to participate in central dispatch and can decline an instruction so long as they immediately re-offer. Transpower has absolute discretion on the decision

[29] Clause 3.8.23 of the NER stipulates the consequences for non-conformance with dispatch instructions both in short and long-term if the non-conformance continues.

[30] More information available: https://www.transpower.co.nz/system-operator/electricity-market/dispatch-capable-load-station-setup

to remove them from the process if they do not comply with dispatch targets issued during their nominated dispatch bid periods.

Proposed scheduled lite design

Scheduled lite model	Proposed requirement	Rationale
Visibility	Resources would not participate in dispatch.	• As the visibility model does not require any responsive capabilities and is primarily focussed on providing intentions of future behaviour, resources would not participate in dispatch or follow dispatch instructions.
Dispatchability	Participants would be required to comply with dispatch instructions but would be bound to a threshold of non-conformance before being exposed to the relevant penalties.	• Not exposing prospective scheduled lite participants to the full suite of compliance risks associated with dispatch instructions will likely be important for encouraging entry into the scheme. • Given the design principle of scheduled lite arrangements to target smaller resources which currently do not formally engage with central dispatch there is potentially more scope to permit a threshold for non-conformance (e.g. must hit 95% of dispatch targets) relative to large, conventional scheduled resources.

However, rather than impacting exclusively operational costs for participants, decisions related to whether participants would be required to comply with dispatch instructions may add material compliance risks and costs to participating in any prospective scheduled lite arrangement.

Question for consultation

34. How appropriate is the proposed approach for the dispatchability model? Will the use of the threshold meaningfully reduce barriers to participation? What are the trade-offs associated with the use of a threshold? How should that threshold be determined (e.g., MW accuracy, or proportion of dispatch targets etc.)?
35. Should an opt-out approach prior to dispatch, like that used in New Zealand, be adopted? Would that meaningfully reduce any barriers to participation?

Communicating behaviour

Currently, scheduled and semi-scheduled resources provide visibility and communicate their behaviour through the use of telemetry. Telemetry requirements can be a barrier to participation in scheduling and dispatch for smaller resources and market participants. Making communications with the system operator control rooms more accessible is a feature of both scheduled lite models.

What is telemetry?

To be classified as a scheduled market participant currently, AEMO must be satisfied that the system has adequate communication and/or telemetry to support the issuing of dispatch instructions and the audit of responses.[31] In practice, AEMO requires these participants to have Supervisory control and data acquisition (SCADA) connections at their facilities to issue and monitor their behaviour in central dispatch.[32] Although these connections are critical for operating within the NEM's existing scheduling framework, establishing and maintaining them are a significant barrier to entry into central dispatch given the granularity of the data they communicate with AEMO control rooms.

There are several local and international jurisdictional examples which acknowledge and address the barriers presented by these conventional telemetry requirements for the benefit of improving access to the central dispatch process. These include:

1. AEMO's virtual power plant (VPP) demonstration project:[33]
    - this project has forgone traditional SCADA connections and instead uses an application programming interface (API) to communicate the activity and intentions of the households which constitute part of the VPP for participation in FCAS markets.
    - Demonstrates that data communications platforms can be created which are sufficiently sophisticated to enable participation in these markets
2. AEMO's wholesale demand response (WDR) guidelines draft determination:[34]
    - in these draft guidelines AEMO proposed that WDR participants would not be required to adhere to the standard requirements for telemetry (SCADA connections) if the units which constitute a WDR participant are geographically dispersed – even if their aggregate maximum response is greater than 5MW at the dispatchable unit identifier (DUID) level.[35]
    - AEMO will only provide these exemptions where it is confident that the aggregation will not materially impact system security or central dispatch constraints.[36]
    - whilst the conditions for this exemption from standard telemetry requirements are limited, they speak to the need for telemetry requirements to more easily incorporate a greater range of resources.
3. Transpower's (New Zealand) dispatch service enhancement project:

31 Refer to Clause 2.2.2(b)(2) of the NER as an example

32 SCADA is an industry term which refers to the remote monitoring devices participants are required to install onto their devices to permit real time data communications with AEMO. Data from SCADA systems is provided roughly every four seconds to AEMO for a number of system variables such as power and system frequency.

33 Project page available here: https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations

34 Project page available here: https://aemo.com.au/en/consultations/current-and-closed-consultations/wdr-guidelines

35 AEMO, Wholesale demand response guidelines, draft determination, p23

36 Ibid, p. 22.

- Transpower has been steadily progressing new dispatch service transitions since September 2019 as it moves away from its legacy dispatch system.
- this new dispatch system permits market participants to continue using traditional SCADA connections to participate in central dispatch.
- alternatively, participants may elect to interact with the market through the newly established dispatch web services where dispatch instructions and data communications are issued through web-based APIs.[37]
- Transpower considers these alternate dispatch protocols will allow participants to consolidate their communications and enable smaller participants to cost-effectively engage in the market by using a protocol which best fits their dispatch operation.

<u>Proposed scheduled lite design</u>

As mentioned above, both scheduled lite models propose different ways of altering the telemetry requirements for improving the accessibility of the central market and dispatch process. The table below sets out how these models differ from the current arrangements with respect to telemetry and the rationale for each approach taken.

Scheduled lite model	Proposed requirement	Rationale
Visibility	Participant activity is communicated ex-post through the provision of 5-minute revenue meters directly to market processes.	• Since December 2018 all new installed meters have been required to record 5-minute resolution data, with participants having up until December 2022 to provide this to AEMO.[38] • this data is currently primarily used for settlement purposes but could be used as an additional input for AEMO's demand forecasts and repurposed as an additional source of demand visibility. • although this would not provide real-time market information for AEMO this approach may be worth pursuing for the purposes of improving demand and generation profile forecasts.
Dispatchability	Participant activity is communicated in real time by formalising the development of telemetry innovations.	• This approach would involve formally developing and supporting a more accessible set of telemetry requirements as has been the case in AEMO's VPP demonstration project or Transpower's dispatch service enhancement project. • Formally developing these arrangements under scheduled lite would permit a greater array of

[37] For more information, refer to Transpower's Web Service Dispatch Simulator Use Guide, available here: https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/UG-SD-785%20Web%20Service%20Dispatch%20Simulator%20User%20Guide.pdf.

[38] AEMC, Delayed implementation of five minute and global settlement, final determination, p. v, available here https://www.aemc.gov.au/sites/default/files/documents/final_determination.pdf.

		resources to directly interface with central dispatch where traditional SCADA links are optimal. • This would be required as any resource which is dispatchable must be able to communicate with AEMO system in real time.

Question for consultation

36. How appropriate are the proposed additional participation elements for the visibility and dispatch models?
37. For the dispatchability model, will the use of lighter SCADA arrangements meaningfully reduce barriers to participation? What other types of solutions could be considered?
38. Aside from those listed above, should the ESB consider any other elements of the scheduling framework when designing additional participation requirements for scheduled lite arrangements?

Incentives for participating in scheduled lite

Both the proposed models for scheduled lite consider making different incentives available to participants for taking part in the scheme. The incentives being considered for scheduled lite participants include:

- FCAS costs
- Civil penalties
- RERT costs
- RRO obligations
- Operating Reserves

FCAS costs

The Frequency Control Ancillary Service (FCAS) are system services used by AEMO to maintain the frequency on the electrical system at any point in time.

There are two broad classification for FCAS services:

- Regulation FCAS – Services to correct a **minor drop or rise** in frequency. These services are sometimes required to adjust for non-linear changes between each 5-minute dispatch interval.
- Contingency FCAS – services to correct a **major drop or rise** in frequency. There are three main time periods for contingency FCAS markets – 6 second response, 60 second response and 5-minute response.

The cost recovery methodology for FCAS services vary depending on the type of service:

- Contingency raise services are currently recovered from generators, as these requirements are set to manage the loss of the largest generator on the system. Costs are pro-rated over participants based on the energy generation in the trading interval.

- Contingency lower services are recovered from customers, as these requirements are set to manage the loss of the largest load. Costs are pro-rated over participants based on the energy consumption in the trading interval.
- Regulation FCAS adopts a causer pays principle and is recovered from generators and customers. The causer pays methodology uses a contribution factor to allocate costs based on 4 second variation in expected and actual consumption/generation in a dispatch interval.

FCAS costs allocated to generators and customers can be significant. For example, in 2020 FCAS costs totalled at $356 million of which regulation FCAS made up $88 million. Under current arrangements, generators are able to take actions to reduce their regulation FCAS causer-pays allocation. As these costs are calculated for individual generators, if the generator does not contribute to the need of regulation FCAS, they are not required to pay its costs. However, as the allocation for non-scheduled generators/customers is calculated at the transmission node, individual end users are unable to avoid their FCAS causer pay allocation. Further, last year end users paid on average 42 percent of all regulation FCAS costs.

As discussed, AEMO and ARENA have launched a 5-minute self-forecast program. Through this program, semi-scheduled generators are required to forecast their likely generation for the five minutes ahead of dispatch. This information is used by AEMO to better manage dispatch, and generators can reduce their regulation FCAS costs if they are able to generate in accordance with forecasts. Anecdotal evidence from the program suggests that some wind farms have been able to significantly reduce their regulation FCAS costs through the provision of these forecasts. As Scheduled lite will provide additional visibility of likely generation/consumption it could be used as a means by which end users could reduce their regulation FCAS costs.

As contingency FCAS costs are incurred from additional resources been issued instructions to turn up or down in response to a major change in frequency caused by a load or generator tripping, additional visibility of a resource would not affect the need for the contingency FCAS being activated. However, if a resource can provide contingency FCAS services, scheduled lite should be able to facilitate this.

Proposed scheduled lite design

Scheduled lite model	Proposed incentive	Rationale
Visibility	Resources would not have to pay regulation FCAS costs if their forecasts are sufficiently accurate.	• In the visibility model, if resources produce forecasts with sufficient granularity and accuracy so that they do not contribute to the need for regulation FCAS, they should be able to avoid any costs associated with this service.
Dispatchability	Resources would not have to pay regulation FCAS costs if their forecasts are sufficiently accurate. Resources potentially able to bid	• As with the visibility model, if a resource does not contribute to the need for regulation FCAS, they should be able to avoid the associated costs. • If the dispatchable resource has the capabilities to provide contingency FCAS, scheduled lite

	into contingency FCAS markets.	should assist in facilitating participation in this market.

Civil penalties

Another possible incentive for participating in scheduled light might be to lower the civil penalties participants are exposed to when directly engaging in the central dispatch process given the extent of compliance risks these provisions currently assign to them.

As discussed in the dispatch instructions sub-section above, there is a trade-off which can be struck between a threshold for non-conformance and the costs of not increasing participation in the central dispatch process.

What are civil penalties?

Civil penalties are penalties for non-compliance with a law. With respect to energy regulation, a civil penalty is a financial penalty (a fine) for not complying with a certain provision of the NER. Throughout the NER, certain clauses are classified as civil penalties where it has been judged that compliance with them is sufficiently important for market operations.[39] Schedule 1 of the National Electricity (South Australia) Regulations lists all of the clauses of the NER which are a part of the civil penalty regime. Historically, the structure of civil penalties has been flat, where non-compliance with a civil penalty incurs a flat initial and daily dollar amount which changes according to whether the offender is an individual or corporation.

In 2021, the civil penalties regime was reformed to assign different tiers to the clauses which fall under this regime.[40] By doing this, the penalty assigned to the relevant participants is able to better reflect the relative severity non-compliance with a particular clause on the market and wider community.

Proposed scheduled lite design

A potential incentive might be to reduce the severity of civil penalties faced by scheduled lite participants, where this reduction would apply to clauses of the NER that they become liable to when entering into the scheme. Only the dispatchability model for scheduled lite would expose participants to new clauses of the NER which have civil penalties attached to them, therefore this incentive would not apply for the visibility model.

Scheduled lite model	Proposed incentive	Rationale
Visibility	Participants would remain liable under all of the civil penalty clauses their operations entail.	• Scheduled lite participants under this model would not be exposed to any new clauses of the NER which have civil penalties attached to them. • Therefore, there would be no change from the current arrangements in this instance.

39 Refer to Clause 4.3.4 of the NER as an example.

40 More information here: https://energyministers.gov.au/publications/proposed-classification-tiers-reform-australian-energy-regulator-civil-penalty-regime.

Dispatchability	The new civil penalty clauses participants would become liable to (such as providing PASA inputs) would be subject to a lower penalty relative to scheduled participants.	• Scheduled lite participants are likely to have a smaller impact on market outcomes relative to fully scheduled participants. • Given the compliance risks of civil penalties can act as a barrier to entry into the central dispatch process, reducing this risk could encourage entry into the scheme.

RERT costs

A possible incentive for participation in scheduled lite is to avoid the Reliability and Emergency Reserve Trader (RERT) costs that would have been allocated in the absence of the load being scheduled. This design option is specific to Market customers (load), as generation does not pay RERT costs. RERT is activated when there is a forecasted reliability shortfall or emergency event in a region, based on the in-market-supply and forecasted demand. When activated, out-of-market resources are shed/generate (RERT contracts are generally with load). RERT costs accrue and are apportioned to load based on relative consumption when RERT is activated in a region, on a causer pays basis. In 2019-20, the total RERT cost was $40.6m and equated to $18,967/MWh.[41]

<u>Proposed scheduled lite design</u>

Scheduled lite model	Proposed incentive	Rationale
Visibility	Relevant load participants would remain liable for RERT costs.	• Loads participating under the visibility model would provide AEMO with a better indication of future market conditions, however they would still contribute to the need for out-of-market resources and RERT under a reliability event.
Dispatchability	Relevant load participants would not be liable for RERT costs.	• Dispatchable load that could be turned down when there is a reliability shortfall would reduce the need for out-of-market resources to be called into the market. • Keeping with the ‘causer pays’ principle as applied to RERT costs, suggests that these resources should not pay RERT costs.

Retail Reliability Obligations (RRO)

Another possible incentive for encouraging entry in scheduled lite might be to exempt volumes of scheduled load from contributing to the POE50+ volume of load that entities must cover as part of their RRO obligations. RRO liabilities form an operational cost for participants and providing an avenue to mitigate this risk may incentivise participants to use scheduled-lite. This could take the form of

41 AEMO, RERT end of financial year 2019-20 report, p7, available at: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2020/rert-end-of-financial-year-report-201920.pdf?la=en

allowing participants in the mechanism to subtract the volume of load that they schedule at T from the POE50+ volume of load that participants provide to the AER when a T-1 trigger is called, which they are liable to cover with qualifying contracts.

<u>What is the RRO?</u>

The RRO is designed to support reliability in the NEM by incentivising retailers and some large energy users to contract or invest in dispatchable and 'on demand' resources.[42] If AEMO identifies a reliability gaps in any of the NEM's regions in the Electricity Statement of Opportunities (ESOO), it will apply to the AER to trigger the RRO. If triggered, liable entities are on notice to enter into sufficient qualifying contracts to cover their share of a one-in-two-year peak demand event. A market customer is a liable entity under the RRO if its annual aggregate annual load is over 10GWh for a particular NEM region. Entities whose required share of load is not covered by qualifying contracts when an assessment day is called, are non-compliant. Noncompliant liable entities will be required to pay a portion of the costs for the Procurer of Last Resort, as well as being subject to civil penalties, up to an individual maximum of $100 million.

Under the RRO scheme, qualifying contracts that contribute to a liable entities' RRO obligations are rated on their 'firmness'. Firmness is the extent to which the contract will reduce the liable entity's exposure to spot price volatility during the reliability gap period. A firmness factor is calculated and assigned to each qualifying contract, in accordance with AER's Interim Contracts and Firmness Guideline.[43] Contracts that are underwritten by intermittent generators generally have a lower firmness rating compared to a scheduled generator.

Progressing this option will depend on careful consideration and coordination with the reform package being progressed under the resource adequacy mechanisms work stream. The mechanics of this option will vary depending on the direction of reform adopted for the RRO, as well as to avoid the risk of double counting load volumes across different mechanisms.

<u>Proposed scheduled lite design</u>

Scheduled lite model	Proposed incentive	Explanation
Visibility	Loads participating under this model at T cannot be subtracted from the volume of load finalised at T-1 that an entity is required to cover with qualifying contracts.	• Resources that participate under the visibility model would not directly add any additional dispatchable or 'on demand' resources to the market or contribute to the purpose of the RRO. • Therefore, the current RRO obligations should remain for these resources.
Dispatchability	Responsive component of loads	• Resources using the dispatchability model to participate in central dispatch would be adding to

42 For more information see: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/RRO%20Bulletin%20-%2020190701.pdf

43 For more information see: https://www.aer.gov.au/retail-markets/guidelines-reviews/retailer-reliability-obligation-interim-contracts-and-firmness-guideline

	participating under this model at T can be subtracted from the volume of load finalised at T-1 that an entity is required to cover with qualifying contracts. Resources could be rated with a firmness factor, to reflect the extent that reduce an entity's liabilities under the RRO.	the responsive capacity of the market, and therefore, if they can effectively reduce the procurement and activation of RERT and actualisation of USE, should be subtracted from the volume of load for which an entity is liable under the RRO. • Additionally, all responsive resources that participate under the dispatchability model should be eligible to underwrite qualifying contracts and be rated for firmness accordingly. Noting that the volume can only be counted as a load reduction OR a qualifying contract.

Operating Reserves

The ESB is currently considering the merits of introducing an operating or ramping reserve market into the NEM. This is also being considered in parallel by the AEMC through two rule change requests from Infigen Energy and Delta Electricity.[44]

Under an operating reserve or ramping market AEMO could procure additional flexible resources close to real time dispatch to help manage the increasing variability and uncertainty in market conditions. This new market could become necessary to integrate higher penetrations of large-scale variable renewables in the NEM over time.

An operating reserve market could be seen as a complimentary measure to scheduled lite. While the visibility and dispatchability models of scheduled lite provides greater certainty of the likely behaviour of non-scheduled resources, the operating reserve would assist in dealing with uncertainty and variability across all resources that contribute to the calculation of net demand.

The ESB and AEMC are currently developing possible designs for an operating reserve or ramping market. This includes considering the appropriate cost recovery approach for any eventual market. The ESB notes that it considers a causer-pays approach is likely to result in the greatest benefits for consumers. This approach could interact with and be an incentive to join scheduled-lite. Resources that participate under scheduled-lite are better able to signal to the market operator their intentions, which would lessen the extent to which they contribute to net demand uncertainty. Those resources may therefore be exempt from or pay a lower rate of the costs of any operating or ramping reserve service that is put in place to address net demand uncertainty across the NEM.

44 For more information on the Infigen Energy rule change see: https://www.aemc.gov.au/rule-changes/operating-reserve-market and more information on the Delta Electricity rule change see: https://www.aemc.gov.au/rule-changes/introduction-ramping-services

Proposed scheduled lite design

Scheduled lite model	Proposed incentive	Rationale
Visibility	Resources could be exempt from or pay a lesser rate under the potential cost recovery of an operating reserve marker, if introduced.	• Resources participating under the visibility model would be providing the market with information on their likely behaviour and reducing uncertainty to the market operator. • If a 'causer pays' principle is considered in the cost recovery methodology of an operating reserve (if introduced), then scheduled lite resources should be exempt from, or pay a lesser rate for the costs associated with procuring additional resources to deal with uncertainty.
Dispatchability	Resources could be exempt from or pay a lesser rate under the potential cost recovery of an operating reserve market, if introduced. If appropriate, resources could participate in the operating reserve.	• As with the visibility model, if a resource submits its intentions/behaviour and complies with these intentions it should also be exempt from operating reserve costs. • Additionally, if a resource in the dispatchability model meets the operational requirements to participate in an operating reserve market (if introduced), then it should be able to bid into that market.

Questions for consultation

39. How appropriate are the proposed incentives for the visibility model, including:
- avoided FCAS costs
- reduced operating reserve costs (if introduced)?
- Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?

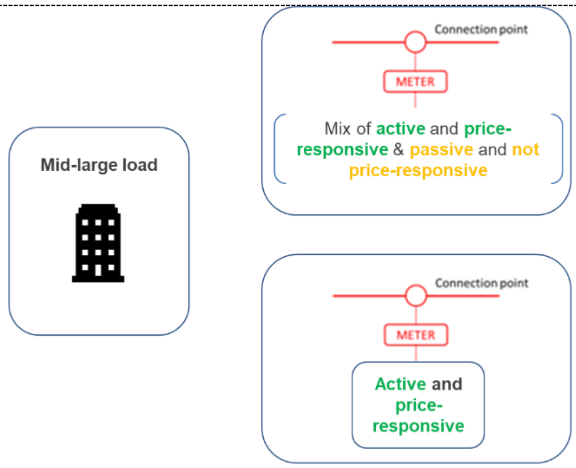
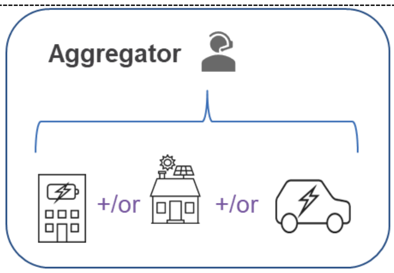
40. How appropriate are the proposed incentives for the dispatchability model, including:
- avoided FCAS costs
- reduced civil penalties
- avoided RERT costs
- avoided RRO costs and the ability to underwrite qualifying contracts (subject to firmness rating)
- reduced operating reserve costs and ability to bid into operating reserve market (if introduced)?

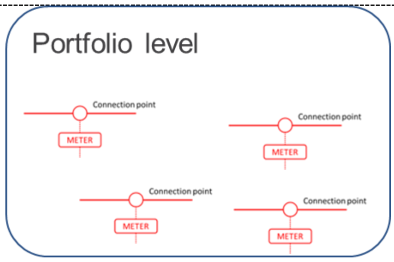
41. Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?

Case studies

Scheduled lite has been designed to accommodate a range of different customer types and market participants. Behind any connection point, there may be a range of different resources with differing characteristics by way of controllability. Using the term ‘resources’ collectively refers to assets (physical unit of any size) and flows (imports and exports). In exploring the characteristics of these resources, it is recognised that resources may be ‘active’ and ‘price-responsive’; or ‘passive’ and not-price-responsive (i.e., price-taker load or passive resources that send out electricity with little/no control). Essentially, there are a range of resources, and many different combinations, which might act in an ‘active’ or ‘passive’ manner.

Two case studies are presented below to further exploring the suitability and practicalities of a potential scheduled lite model. These case studies are non-exhaustive but are provided as examples for reflection and consideration.

<table>
<tr>
<td>A mid-large customer with a mix of active and passive resources behind a single connection point</td>
<td>
</td>
</tr>
<tr>
<td>A market participant with a mix of active and passive resources representing their portfolio of small customers</td>
<td>


</td>
</tr>
</table>

Questions for consultation

42. Are there benefits of making a distinction between active (or controllable) and passive (not controllable) behaviours behind a connection point?
43. How might a market participant (retailer; aggregator) provide information across their portfolio (many connection points)?

4. Transmission and Access

4.1. Case studies re access and congestion issues

This section describes further evidence and analysis of the nature of the issues sought to addressed in transmission access reform as set out in Table 3 in Part A, Chapter 5.

Need for locational signals and the role of REZs

The International Energy Agency[45] and International Renewable Energy Agency (IRENA)[46] have both identified locational investment signals as a feature of a market design that can support high levels of variable renewable energy. While the current NEM design provides some locational signals, these are incomplete and do not adequately incentivise new generators and storage systems to make the best use of existing and new transmission capacity.

The Directions Paper set out the ESB's intent to focus on Renewable Energy Zones (REZs) as a tool to provide locational signals to generators. A REZ framework can promote coordination of generation and transmission by making it more attractive for project developers to invest in certain parts of the network. Generators, storage providers and demand side resources could be incentivised to participate in a REZ using a set of "carrots" which could include scale efficient connection assets, a simpler connection process and a level of access protection.

REZs rely on a planning-based approach to decide which parts of the network are best suited to development. Under a REZ model, the ISP (or other centralised model, such as government policy) is used to determine the location of new generation developments.

Several State governments have announced policies to develop REZs, and the ESB is working closely with governments on these matters. The ESB's work is intended to provide the fundamental principles for REZ implementation which may be complemented by the work of State governments.

As a planning-based measure, REZs can only address the need for co-ordination in investment timeframes. Without additional supporting reforms, REZs will not improve the efficiency of dispatch outcomes in operational timeframes (except insofar as coordinated development reduces incidences of congestion in the first place). However, the ESB expects transmission congestion to increase, even after the actionable ISP transmission investments are built.

45 International Energy Agency (2017) Getting Wind and Solar onto the Grid – a manual for policy makers. Available at: https://www.iea.org/reports/getting-wind-and-solar-onto-the-grid

46 IRENA (2019), Innovation landscape for a renewable-powered future: Solutions to integrate variable renewables. Available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Innovation_Landscape_2019_report.pdf

Box 3 Locational signals provided by marginal loss factors

Some stakeholders have suggested that the current marginal loss factor (MLF) regime provides a locational signal to investors. While it does provide a form of signal for generators about where to locate, MLFs are not designed to measure congestion. Rather, MLFs are used in the NEM to adjust electricity prices to reflect the marginal cost of energy lost in transporting electricity across networks. This does not reflect the impact that electricity generated at a point on the network has on congestion across the entire network.[47]

The NEM Dispatch Engine (NEMDE) currently calculates the cost of congestion for each generator connection point (DUID) as part of its solving process. It is therefore possible to calculate the correlation between the cost of congestion for each generator connection point and the MLF that each generation unit has been assigned for a given financial year.

A correlation coefficient of 1 indicates that the two variables are perfectly positively correlated, which means that 100% of the time, the variables in question move together by the exact same percentage and direction. A correlation coefficient of -1 indicates that the two variables are perfectly negatively correlated, meaning that 100% of the time, two variables move together by the opposite percentage and direction. A score of zero indicates that there is no correlation between the two variables, meaning that they move independently of each other. The results of this analysis are shown below.

Correlation between MLF and average price adjusted for congestion

Financial year	Correlation coefficient between MLF and average price adjusted for congestion for all DUIDs
2016-17	0.127
2017-18	0.249
2018-19	0.239
2019-20	-0.009

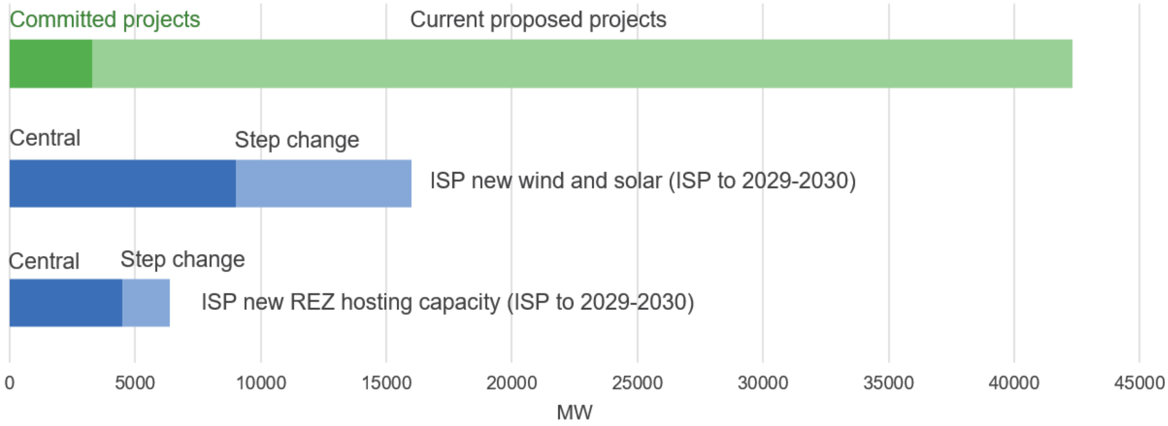
The ESB acknowledges that there are some limitations in this analysis, however it provides a strong indication that MLFs are not good substitutes for price signals that reflect congestion. Reform is needed to make sure that the energy transition is accomplished in a way that does not burden consumers with the cost of poorly targeted investments.

New transmission build will not eliminate congestion

Congestion is a normal, everyday feature of efficiently sized transmission infrastructure to accommodate variable renewable generation – not an anomaly. Figure 14 compares the amount of committed and proposed projects to the level of new investment required under the ISP optimal development path.

47 It is also possible to have price signals that reflect the combination of congestion and losses.

Figure 14 NEM committed and proposed solar and wind projects vs ISP optimal development path



Source: ESB analysis of AEMO data[48]

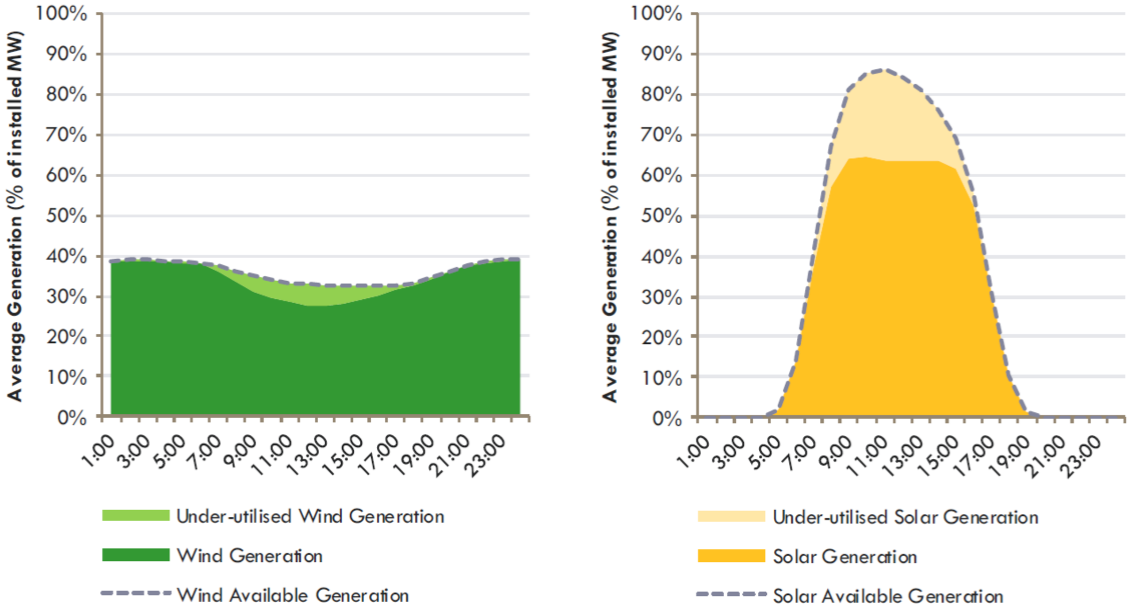
The actionable ISP transmission projects intended to alleviate congestion are much smaller than the total amount of proposed new generation projects. For instance, EnergyConnect has a rated transfer capacity of 800 MW, which is dwarfed by the 10 GW pipeline of proposed new generation capacity in South Australia, as well as a number of proposed projects in Southern NSW, some of which may eventually seek to connect to the NEM.

The 4.5 GW of new transmission capacity that becomes available over the next decade under the ISP central scenario is also significantly less than the nearly 6 GW of new generation that commenced operation and become committed during 2020. Even under the step change scenario - which involves 10 GW of new transmission hosting capacity over the next decade - investment levels are much lower than in recent years. Some of the new generation will connect to the existing network, however, it appears likely current generator concerns regarding congestion are unlikely to be wholly alleviated by new transmission build. This is to be expected because the current market design systematically incentivises generation investment at a rate that exceeds the least cost development path identified by the ISP.

Congestion is likely to increase because the cost of building the incremental transmission infrastructure to allow for the dispatch of variable renewable generation for the sunniest or windiest of times exceeds the benefits to reducing the cost of dispatch or reducing emissions at those times. It is more cost effective, and reduces emissions by a greater extent, to build more variable renewable generation than can always be accommodated by the transmission infrastructure, even if that variable generation cannot be always used.

48 The new transmission hosting capacity in this chart does not include existing spare hosting capacity that would also be available for new connections. The current proposed projects include a group of pipeline projects that are at different states of development – including some which may not reach financial decision or connection application and as such, the actual projects that eventually seek to be connected may be much lower. On the other hand, the committed/proposed projects row includes only those generation projects that currently meet the relevant criteria and does not include new generation projects that may emerge between now and 2030. See AEMO generator information: (https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information) for more information on the proposed projects and their development status.

Figure 15 Average utilisation of utility scale wind (left) and solar (right), neutral scenario

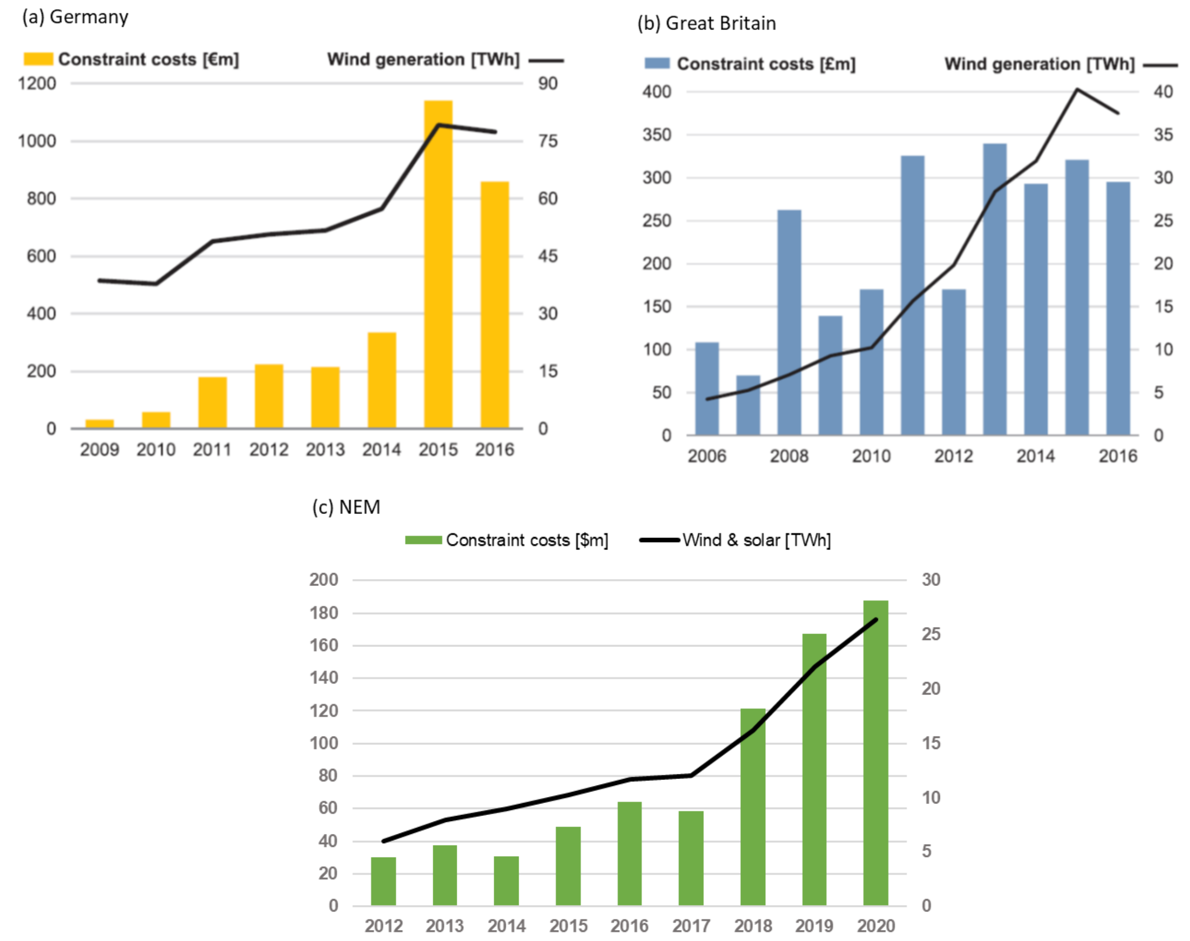


Source: AEMO, 2018 ISP, p36

It can be profitable for solar developers to build solar farms that produce surplus output during the middle of the day, to be able to produce more during the lucrative shoulder periods. It would be inefficient for the transmission network to be able to accommodate all this surplus generation.

The ISP does not, and should not, seek to remove all congestion from the system, meaning that issues relating to access will be common despite the transmission infrastructure expansions foreshadowed by the ISP.

Figure 16 VRE output and constraint costs, Germany, Great Britain and NEM



Source: Joos and Staffel[49] (Germany and Great Britain), ESB analysis of AEMO data (NEM)

Need for congestion management in operational timeframes

In operational timeframes, the current framework can rise to inefficient and complicated results in the presence of congestion. This is because the regional pricing model creates a divergence between what happens on the power system and what happens in the wholesale market. The current market design does not efficiently manage congestion in operational timeframes. Instead, during periods of congestion the dispatch algorithm applies simplified rules that reward market participants for acting in a manner that is inconsistent with economic efficiency.

One such inefficiency that arises is a consequence of 'disorderly bidding', also known as 'race to the floor bidding'. In the presence of congestion, generators know that the offers they make will be unlikely to affect their regional reference price. The profit maximising behaviour of a generator is to bid at the market floor price of -$1,000/MWh. This maximises their individual dispatch quantity, and hence the revenue they receive (the dispatch quantity multiplied by the regional reference price). All generators affected by the constraints are incentivised to maximise their share of the limited

[49] Joos and Staffel (2018), Short-term integration costs of variable renewable energy: Wind curtailment and balancing in Britain and Germany, Renewable and Sustainable Energy Reviews 86 (2018) 45–65.

transmission capacity by engaging in this 'race to the floor' bidding behaviour: not racing to the floor when one's competitors are doing reduces the generator's share of dispatch, and hence revenue.

The NEM dispatch engine selects market participants to be dispatched by minimising total as-bid costs while ensuring that the pattern of dispatch is consistent with the physical capacity of the system. It uses as an input the bids made by market participants; it does not distinguish between the underlying actual costs of generators. As a result, in the presence of congestion and disorderly bidding, dispatch is shared based on administered rules between generation with high and lower underlying costs, all of whom are bidding at the same price. This results in productive inefficiencies – it would have been more efficient for the lower cost generation to be dispatched ahead of the higher cost generator – and ultimately in higher prices for consumers.

Analysis of dispatch inefficiencies and congestion in the grid show that over time the impact and associated costs of these issues are likely to significantly increase. NERA modelling undertaken for the AEMC[50] estimates that costs arising from race to the floor bidding could reach up to NPV $1 bn over the period from 2026 – 2040 ($2020). Analysis of international case studies suggests benefits to consumers from efficient dispatch signals could be in the order of up to $137 million per year.[51]

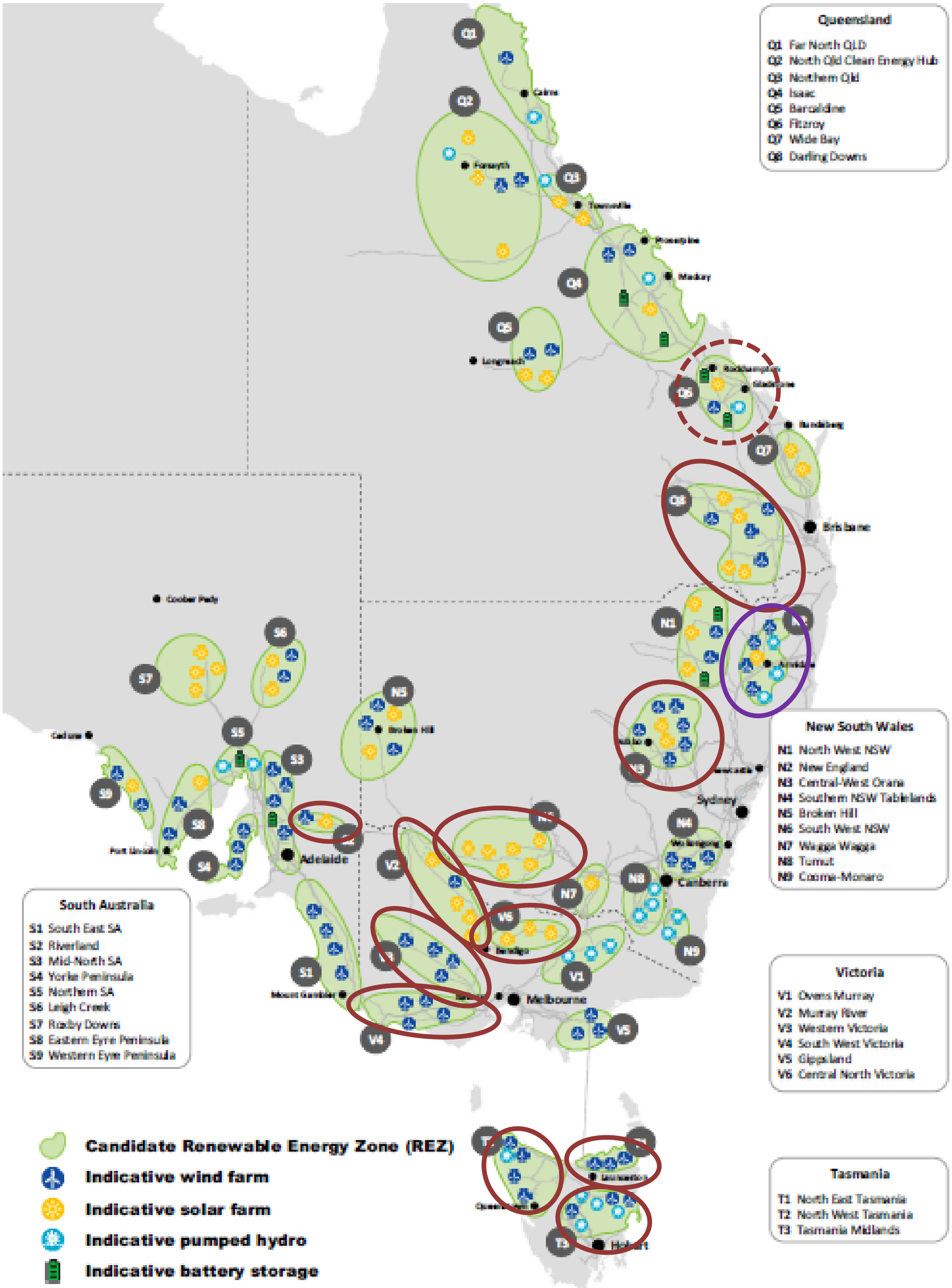
Risk of underutilisation of interconnectors

The current access regime also creates specific problems around the treatment of interconnectors and inter-regional flows. Of the 12 REZs identified for further development in Phase 1 and 2 of the 2020 ISP, all but the Fitzroy REZ are located on interconnector flow paths. The New England REZ (which is slated for 8 GW of additional generation capacity under the NSW Electricity Roadmap – shown in purple below) is also located on an interconnector flow path.

[50] https://www.aemc.gov.au/sites/default/files/2020-09/NERA%20report%20Cost%20Benefit%20of%20Access%20Reform%202020_09_07.pdf

[51] Some generators have indicated that these costs could be overstated because their trading systems are not sophisticated enough to engage in race to the floor bidding. The ESB notes that this could have the opposite effect and increase the costs of disorderly bidding. If the parties that don't rebid are the new entrant renewable generators, and the parties that do rebid are the larger thermal incumbents, then partial race to the floor bidding could result in the more expensive generation receiving a larger share of dispatch than they would if everyone raced to the floor.

Figure 17 Phase 1 and 2 REZs in 2020 ISP (red), plus New England (purple)



This investment pattern is efficient; as historic underinvestment in interconnectors is resolved, new transmission capacity becomes available along these routes. However, this trend also creates a pressing need to address flaws in the current market design.

As discussed in the January Directions Paper,[52] when congestion arises between a generator and its regional reference node, if the generator is able to access an interconnector, they may instead be dispatched into a neighbouring region. This generator will still be paid the price that applies in its home region. If the price is high in the home region due to the congestion, then counter-price flows may occur.

When the value of counter-price flows across an interconnector exceeds a certain level, the Rules require AEMO to "clamp" the interconnector (i.e., change dispatch outcomes so that the counter-price flow ceases). This requirement is designed to protect customers from large negative inter-regional settlement residue balances, which would manifest as an increase in transmission use of system charges. While there is a clear justification for clamping, it represents a sub-optimal use of interconnector assets that arises due to flaws in the market design.

Incidences of clamping are likely to increase in materiality as REZs are developed near the regional boundaries. As these issues arise due to price outcomes rather than underlying costs, they are not taken into account in the ISP and RIT-T assessments. There is a risk that interconnector investments will not deliver the anticipated market benefits if clamping becomes a frequent occurrence.

The congestion management model has the potential to address flaws in the current treatment of interconnectors, however, this is a complex issue that could have flow-on consequences for other aspects of the market design.

Appropriate signals for storage and demand response

Market designs that provide more localised price signals would open up new business opportunities for emerging technologies so that they are able to fulfil their key roles within a high variable renewable energy power system. This section provides two case studies: batteries and hydrogen.

Case study 1: Batteries

The recent history of large-scale battery deployment in the NEM is one of rapidly declining costs, increasing interest in the technology and a few landmark early developments. Batteries can be more rapidly deployed than traditional firming capacity and in many contexts are more flexible in terms of where they can locate.

As of January 2021, the storage capacity of the battery fleet in service in the NEM is 327 MWh. The storage capacity of all projects that have been publicly announced according to AEMO or are in the development phase is 12,370 MWh. Whilst this is likely significantly larger than the capacity that will actually built in the near term, other sources are estimating over 900 MW of battery energy storage will be delivered to the NEM by 2024.[53] Therefore, it is important that the market design incentivises efficient operation and location of battery storage.

Batteries in the NEM have to date been deployed under business cases that attach greater emphasis to frequency control ancillary services (FCAS) market revenues than energy arbitrage revenues to recoup their investment costs. However, with FCAS revenues being relatively small and likely to reach saturation with further battery entry, it is likely that energy arbitrage along with network service

52 ESB (2021) Post-2025 Market Design Directions Paper, p95.

53 https://www.pv-magazine-australia.com/2020/12/11/new-research-gauges-australias-battery-energy-storage-pipeline-at-7-gw/

provision will become a crucial component for many battery business cases at some point in the future, especially as costs of batteries continue to decline.

The current market design does not reward batteries for alleviating congestion. Instead, batteries are incentivised to behave like a generator, even though they have a broader range of capabilities. More granular local prices could enable batteries to compete with both generation and transmission, for instance by enabling batteries to become virtual transmission lines that earn revenue by arbitraging differences in local prices. Batteries targeting revenue from arbitrage are prevented from receiving greater intra-day price spreads than those that occur at the regional reference node. Due to intra-regional congestion, there are locations (nodes) on the network where the difference between the highest and lowest price in a day is not the same as the difference at the regional reference node, with some of the spreads being smaller, and some larger, depending on the impact of generation at that location on congestion in the network (see Table 3).

Table 2 Summary of average intra-day price spreads by NEM region

Region	Average Price Spread Lowest Node	Average Price Spread RRN	Average Price Spread Highest Node	Difference Between High and Low	Difference Between High and RRN
NSW	95	102	280	185	178
QLD	79	91	91	12	0
SA	199	223	274	75	51
TAS	103	106	170	67	64
VIC	135	207	274	139	67

Source: ESB using the AEMO MMS database, 2019

By definition, the location with the biggest intra-day nodal spreads provides the biggest difference in value to the system of relieving congestion when charging (perhaps when sited next to wind or solar farms away from a load centre) and discharging when demand is high and lines are relatively free of congestion (perhaps in the evening peak when the sun has set) in a single day. The inability to access these prices means that batteries:

- Are not able to capture the full value they can provide to the power system and therefore under-incentivised to enter the market in aggregate;
- Do not receive efficient price signals to locate at nodes where they can provide the most value to the power system. Given storage's inherent flexibility in location decisions, this is likely to result in significant inefficiency in the medium to long term.

The current design also does not provide efficient operational incentives for batteries. Profit-seeking batteries are not rewarded accurately for the impact they have on congestion management. This is because it receives the same price in its region, regardless of what congestion is near where it is located. If there is high congestion in its area, there would be system-wide benefits for the battery to charge, alleviating congestion. However, if the regional price is high at this time then the battery will not have the appropriate incentive to do so. Conversely, if there is little congestion in its area, then it should export, but again the current incentives do not create this effect. This undermines the value that batteries can offer to the system, particularly where they are needed to support flexible resources.

Case study 2: Hydrogen

Deloitte in their report supporting the National Hydrogen Strategy[54] have estimated that the potential load associated with hydrogen production could be as large as 912 TWh.

With appropriate market structures, there are substantial benefits to the NEM as a wider system from large hydrogen projects choosing to be grid connected for either some or all of their load. These relate to the increased supply of demand response and FCAS services, but also more widely to the ability of such large loads to co-locate with large renewable developments and manage their consumption over their operating cycles to match the output profiles of the increasing amount of renewable generation in the NEM. Storage or load that can follow the output profile of variable renewable energy can absorb surplus renewable energy during windy and/or sunny periods and reduce demand during periods of scarcity.

One of the biggest decisions facing the hydrogen industry at the moment is whether to locate on or off grid. This is coupled with the challenge of financeability and ensuring projects are competitive. There are many benefits to the grid of hydrogen choosing to locate on-grid, however the current access framework does not adequately incentivise hydrogen to do so.

The shadow LMPs produced by AEMO can serve as an estimate of the cost of congestion at a particular location on the network.

The average price of the shadow LMP at Gladstone was $8.14/MWh lower than the QLD RPP in 2019. Additionally, in Victoria the average price difference between the lowest priced node and the RRP in 2019 was $15.2/MWh. This significant difference in prices and therefore the cost of energy to a new large load like hydrogen, reflects the potential value to the underlying economics of new hydrogen production capacity, where it can locate at the lower priced nodes in each region of the NEM. While this may be a crude metric, it does however give an indication of the price differences available under a framework that includes prices that reflect the impact of congestion. Given that approximately 70% of the cost of green hydrogen is the cost of electricity input, access to these price fluctuations will be critical to support the business case for grid connected green hydrogen. The importance of having access to this significant price difference is discussed in Box 4.

Box 4 Economics of hydrogen and the importance of the cost of electricity

The economics of hydrogen production from the use of renewable energy resources is improving with reductions in capital costs for electrolysers. In 2018, electrolysis costs under PEM technology were estimated to be $6.08-7.43/kg in the CSIRO's National Hydrogen Roadmap. In the longer term, hydrogen production costs between at or below $2/kg, the "H2 under $2" target, are targeted as part of efforts to create a sustainable and competitive industry.

Analysis based on the CSIRO's National Hydrogen Roadmap makes it clear that energy costs will play a key role in ensuring the hydrogen industry is competitive longer term. The analysis shows

54 https://www2.deloitte.com/content/dam/Deloitte/au/Documents/future-of-cities/deloitte-au-australian-global-hydrogen-demand-growth-scenario-analysis-091219.pdf

that for every $10/MWh improvement in the electricity price, the cost of hydrogen is lowered by approximately $0.45/kg, assuming improvements in the efficiency of electrolysers take place.

Appropriately incentivised, hydrogen could help the power system to integrate more renewables by acting as a load as well as a potential source of supply. As with batteries, hydrogen and other flexible loads can alleviate transmission congestion by locating near or within REZs. This is particularly important given the potential size of hydrogen load to be developed as well as the associated VRE that will be built to support the increase in demand from the hydrogen production market.

More insights on the developing hydrogen industry and the role it can play in the NEM will be available as part of the AEMC's hydrogen policy spotlight series.[55]

4.2. Medium term access solutions

This section describes each option in more detail and assesses their strengths and weaknesses against the ESB's access reform objectives. The options considered are:

- A congestion management model
- Congestion management model with REZ adaptions
- Connection fees
- Generator TUOS
- A hybrid model of connection fees and the congestion management model.

Congestion management model

Model overview

As under the current arrangements, generators would continue to be settled at the regional reference price[56] for their energy.

This model introduces two mechanisms which work in tandem.

1. First, scheduled and semi-scheduled market participants would face a ***congestion management charge***, calculated each dispatch interval as the market participant's marginal impact on the cost of intra-regional congestion in the dispatch interval.
2. Second, market participants that are exposed to the new congestion management charge would receive a **rebate**, calculated each dispatch interval, funded from the collective revenue received from the congestion management charges. This rebate would seek to replicate, in broad terms, the way that congestion risk is currently shared between market participants through the dispatch process – on the basis of the market participant's availability, the transmission capacity and the degree to which the dispatch of the market participant contributes to the intra-regional constraint. Collectively, in each dispatch interval the rebate provided to market participants would equal the total congestion management charge received from market participants.

55 https://www.aemc.gov.au/hydrogen-new-australian-manufacturing-export-industry-and-implications-national-electricity-market?utm_medium=email

56 Multiplied by their marginal loss factor.

This approach:

- exposes market participants to the marginal cost of intra-regional congestion in each dispatch interval, reducing incentives to 'disorderly bid' and so promote dispatch efficiency
- provides a hedge to incumbent market participants against the cost of this congestion that results (in combination with the rebate) in financial outcomes for the incumbents that are broadly consistent with the current arrangements, limiting the disruption to existing market participants as a consequence of the changes to the access arrangements
- given how it is framed, ideally minimises consequential changes to participants contractual arrangements and power purchase agreements
- provides more accurate information to market participants, AEMO, TNSPs and the AER relating to the cost of congestion.

In the basic form of the congestion management model, rebates are made available to all generators, including incumbents and new entrants. This means that the model does not provide locational signals, because the refund offsets the signal created by local prices. The adapted congestion management model mechanism, modified for new generation investment and REZs, is discussed below (see page 98). When adapted to accommodate REZs, this model also incentivises generators to connect in efficient parts of the network, because they will have a better ability to manage congestion risk in these locations than other parts of the grid.

Congestion management charge reflective of marginal cost of congestion

In order to address the issues of congestion in the NEM, the proposal introduces a congestion management charge for market participants which is calculated each dispatch interval. This charge is calculated as the marginal cost of congestion caused by the market participant – something that is already calculated by the dispatch engine – and is on a $/MWh of dispatched energy basis.

The net effect of a generator being settled at the RRP, and then paying the congestion management charge, is for generators to be settled at their locational marginal price (LMP) (noting that generators will also receive a rebate, so that their total payment through the market is not the LMP).

This means that market participants will be incentivised to make operational decisions that promote consumers' interest in the market. This will be important given the increased interconnection and so potential for increased counter-price flows, as well as congestion more generally. While generators will be incentivised to bid consistent with their underlying costs, they will also receive a rebate that leaves incumbent generators largely unaffected in the payouts that they receive.

Congestion management charge rebate

Market participants would also receive a rebate on their congestion management charge. The rationale behind the design of this rebate is that market participants would be broadly financially indifferent to the introduction of the congestion management charge compared to the status quo arrangements (while the congestion management charge, described above, improves dispatch efficiency).

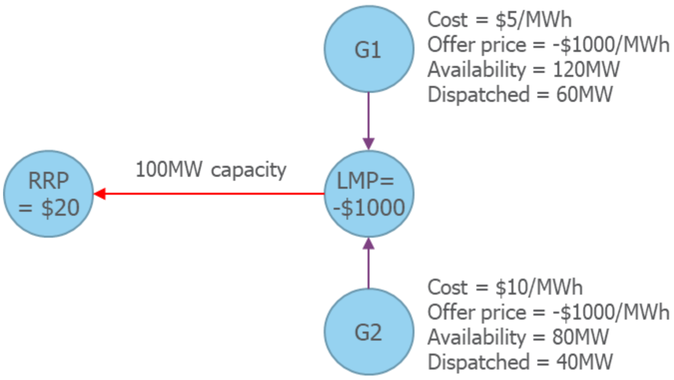
Under the current arrangements, in the presence of congestion and disorderly bidding, a generator's dispatch, and so revenue, is a function of:

- the generator's **availability** in comparison to the availability of other generators participating in the binding constraints. This is because tie-breaking of bids which have identical impacts on the cost of dispatch as calculated by the dispatch engine[57] is done on the basis of generators' availability
- the degree to which the generator contributes to the binding constraints in comparison to other generators
- the available transmission capacity.

The revenue received from the congestion management charge is then shared among incumbent market participants as a rebate, with each participant's individual share being determined as a function of the factors listed above. This in turn means that incumbent generators are largely financially indifferent to the introduction of this regime.

A simple example of this is provided for a radial line, below, which ignores the effect of losses for ease of explanation:

Figure 18 Current arrangements with disorderly bidding



Under the current arrangements, it is privately profit maximising for both generator 1 and generator 2 to offer at the market floor price: -$1,000/MWh. As the dispatch engine is unable to distinguish between the underlying costs of the generators, it pro rates their dispatch quantities in proportion to their availabilities. There is 200MW of available generation behind the constraint, of which generator 1 has 120MW (60%) and generator 2 has 80MW (40%). Given the limit on the radial transmission line is 100MW, generator 1 is dispatched for 60% of this (60MW) and generator 2 for 40% (40MW) - in proportion to their availability.

This dispatch pattern is inefficient and so creates costs for consumers. Generator 1 has lower underlying costs and so it would be more efficient for the system as a whole for generator 1 to be dispatched for 100MW and generator 2 dispatched for nothing. But this is not profit maximising for generator 2, who would prefer to be dispatched and be paid the RRP. Depending on the relative carbon emission intensity of the generators, this outcome is also likely to be more carbon intensive,

57 The dispatch engine minimises the cost of dispatch based on the offers of generators, not the actual underlying costs. Regional pricing means that generators are incentivised to bid inconsistent with their underlying costs (in a "disorderly" manner), meaning that the dispatch optimisation based on these inputs is inefficient.

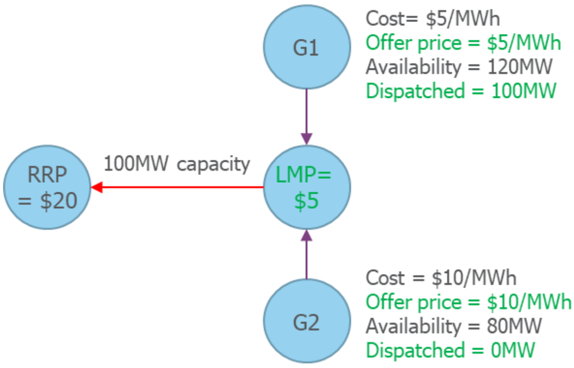
as thermal generators tend to have higher variable costs than variable renewable generators. The profitability of each of the generators is provided in the table below:

Table 3 Financial outcomes under status quo arrangements

	Price received ($/MWh) (A)	Cost incurred ($/MWh) (B)	Quantity generated (MW) (C)	Profit ($/h) (A – B) x C
Generator 1	20	5	60	900
Generator 2	20	10	40	400

Figure 19 compares the outcomes for under the congestion management model.

Figure 19 Outcomes under the congestion management model



Because the generators each face a congestion management charge which reflects the local marginal price, they offer reflective of their marginal costs (changed outcomes shown in green in Figure 18). To do otherwise would risk either not being dispatched or being dispatched for a price that is lower than their costs if their bid is too low. This is of course simplistic, but a useful assumption for illustrative purposes.

Given these offers, the dispatch engine dispatches 100MW of generator 1 and zero MW of generator 2. However, the financial impact on generator 2 is mitigated by the congestion management rebate.

The marginal cost of congestion, and hence the congestion management charge, is equal to the difference between the RRP and the LMP: $15/MWh. This results in total rebates paid by the generators (in this case all by generator 1) of $1500/h, because there is 100MW of flow on the transmission line.

This is then divided between generator 1 and generator 2 in the ratio of their availability behind the constraint: 60% to generator 1 ($900/h) and 40% to generator 2 ($600/h).

The overall financial outcomes for the generators are outlined in Table 4.

Table 4 Financial outcomes under congestion management model

	Price received ($/MWh) (A)	Cost incurred ($/MWh) (B)	Congestion management charge ($/MWh) (C)	Quantity generated (MW) (D)	Rebate (E) ($/h)	Profit ($/h) (A – B – C) x D + E
Generator 1	20	5	15	100	900	900
Generator 2	20	10	15	0	600	600

The following results arise:

- Under the congestion management model generator 2 is better off: because the total cost of dispatch collectively across all the generators has decreased but the revenue received from all consumers is the same, so the **collective profitability of the generators has increased**. In this case the benefits have accrued to generator 2, who has been compensated for not being dispatched *and* avoided costs associated with physical dispatch.
- **Settlement balances.** All the revenue collected from the congestion management charge is exactly allocated back to the generators as rebates.
- The **dispatch efficiency has improved under the congestion management model compared to status quo**. Under the current arrangements, the generators physically share the constraint, despite having different underlying costs. Under the congestion management model, generators have an incentive to bid reflective of underlying costs, because the share of the rebates available would not be dependent on the volume for which a generator is dispatched. Increasing their volume by disorderly bidding may increase their congestion management charge (which is calculated on a $/MWh basis), without an equivalent increase to their rebate. In turn, the dispatch engine will select the lowest cost generation combination.

It appears to be always the case that the incentives for dispatch efficiency will be improved, and that generators will be *collectively* more profitable (or no worse off) under the congestion management model.[58]

Under the simple example above, which has a radial constraint (i.e., a single route for power to travel from generation to load) the allocation is on the basis of availability alone. More complicated situations which include meshed networks and where there are multiple constraints binding simultaneously require a more sophisticated approach, which also takes into account the participation factors of the generators in the constrained transmission lines.[59] Participation factors represent the proportion of a generators' output which flows across a constrained transmission line and are already used by the dispatch engine.[60]

58 At least in the short run. Over time, we would expect that competition would erode the increase in profit to generators, to the benefit of consumers.

59 This more sophisticated settlement algebra is found here https://www.aemc.gov.au/sites/default/files/content/bd0bae75-0d9a-4c14-a2db-de275ab88209/International-Power%2C-AGL%2C-TRUenergy%2C-Flinders-Power%2C-Loy-Yang-nbsp%3B-4-April-2008.pdf pp.9-11.

60 On meshed networks, participation factors vary between -1 and +1. On radial parts of the grid, the participation factor is always exactly 1 (or minus 1). Because all the generators behind the constraint have exactly the same participation factor, this simplifies the more complicated settlement algebra discussed in the footnote above to give the simple result that the revenue received from the congestion management charge in allocated in proportion to just the generators' availabilities.

While the example above resulted in no individual generator being worse off than the status quo, this is not always the case on a meshed network, nor when the cost of the generators exceeds the RRP. More detailed quantitative assessment is required to understand the circumstances when this arises. Nevertheless, the sharing approach to determining the rebate for individual generators attempts to *broadly* replicate the existing way in which congestion risk is shared between generators (as occurs under disorderly bidding), while at the same time attempting to create efficient dispatch incentives.

Storage and load

Load (and storage when acting as load, which from now on will simply be called load for simplicity of explanation), alleviates congestion when it is behind a constraint. Consequently, the congestion management charge for load will be negative, meaning that the load pays the regional price and then receives the marginal *reduction* in the cost of congestion it alleviates. In combination, the load will therefore pay its locational marginal price – which will be lower than the regional price.

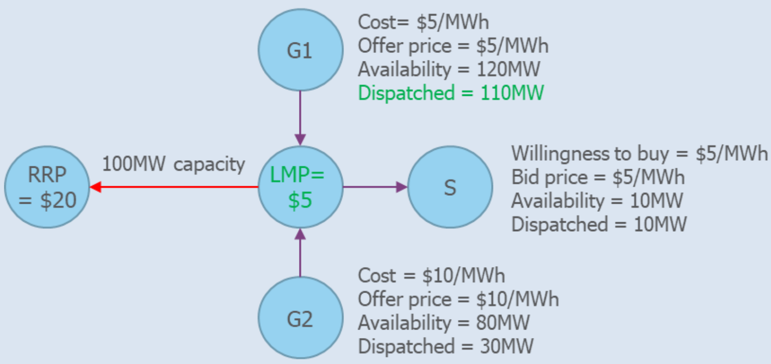
This sends the appropriate and efficient signal in investment and operational timeframes with regard to storage and load, such as hydrogen, as discussed in earlier in this appendix (section 4.1).

It may be appropriate for only scheduled load to receive/pay the congestion management charge, protecting non-scheduled load from the prospect of positive congestion management charges which would mean they pay more than the regional reference price.

It may also be appropriate for the load subject to the congestion management to *not* receive the rebate (which again may be negative).

This would be better for the individual load and better for the system as a whole, as receipt of the (negative) rebate would disincentivise load from locating in parts of the grid where they alleviate constraints. Figure 20 provides an example of how this would work.

Figure 20 Operational incentives for storage under the congestion management model



Both generator 1 and 2 are solar generators, and the dispatch interval is in the middle of the day. As a result, both generators are capable of generating a combined output of 200MW, absent of transmission congestion. The introduction of a storage unit, S, means that 10MW more generation is dispatched, all of which is from generator 1 as it is the cheapest and still has sufficient capacity. Less renewable generation is spilt.

The storage unit pays the RRP, but then pays the (negative) congestion management charge of $15/MWh, meaning that overall, it pays the LMP of $5/MWh. There is still $1500/h of settlement residue, and this continues to be allocated on the basis of the two generators' availabilities (i.e., 60% and 40%, respectively). The financial outcomes of each of the generators and storage is provided below:

	Price received (\$/MWh) (A)	**Cost incurred (\$/MWh) (B)**	**Congestion management charge (\$/MWh) (C)**	**Quantity generated (MW) (D)**	**Rebate (\$/h) (E)**	**Profit (\$/h) (A – B – C) x D + E**
Generator 1	20	5	15	110	900	900
Generator 2	20	10	15	0	600	600
Storage	20	0	15	-10	0	-50

Storage would pay \$50/h or \$5/MWh, whereas under the current arrangements it pays \$200/h or \$20/MWh (the regional reference price). When the sun sets, and the constraint is alleviated, the storage can then discharge and receive the regional price at that later time, with a higher arbitraged profit as a result.

The result incentivises for storage to operate and invest efficiently, based on the principle that prices should reflect marginal costs. In contrast, under the current arrangements, storage may be incentivised to not locate behind the constraint in the first place (because it is unable to financially capture the economic benefit it provides to the system) or may even engage in disorderly bidding in competition with generators 1 and 2 to export to receive the RRP – exacerbating the constraint and causing yet more renewables to be spilt.

Implementation and transitional costs

While AEMO has not yet undertaken a detailed assessment of the cost and timing of implementing the model, relevant information needed for calculating the various components of the model are available (such as the participation factors that represent the impact generators have on network flows). It is likely that the model does not require major changes to the dispatch engine. This is likely to reduces complexity, cost and timeframes compared to, for example, the introduction of dynamically calculated marginal loss factors and volume weighted average pricing for non-scheduled market participants, as contemplated for the enduring NEM-wide access reforms. However, it would require a change to the existing settlement methodology given previous analysis of a similar model took place over five years ago, new analysis and testing will be required to ensure that it stands up to the recent changes to the electricity system, such as five-minute settlement. Overall, the regulatory, administrative and transitional costs associated with the reforms, for both AEMO and market participants, would be easier than anticipated for the LMP/FTR approach but would still require steps to undertake further design, scoping, timing and cost, and it may (or may not) be a sizeable implementation task for AEMO and participants.

Table 5 Assessment of congestion management model

Objective	Assessment
Efficient congestion management signals in operational timeframes	Efficient operation would be promoted under this model. By exposing market participants to the marginal cost of congestion, the efficiency of dispatch and the ability of the system to manage congestion, would be increased.
Efficient locational signals in investment timeframes	As rebates are provided to all market participants (with the possible exception of storage and load as discussed above – noting that they may be better off as a result because their rebate may be negative), this may reduce the incentives for efficient locational investment decisions going forward given that new investing generators know they will enjoy the rebate even if they locate where it is heavily congested. A potential solution is discussed below.
Efficient signals for storage	Both efficient operation and efficient investment for storage will be promoted under the model, because storage will be exposed to the efficient price – the regional reference price less the marginal cost of congestion.
Ability for generators to manage risk	This model removes the existing volume risk for generators through the elimination of incentives to 'race to the floor' and the necessity for the existing tie breaker methodologies in dispatch to determine dispatch quantities. This model introduces basis risk for generators through the introduction of congestion management charges. The introduction of the refunds is designed to mitigate this risk by leaving generators equal to or better off than under the status quo. However, the refunds will not be perfect at achieving this outcome for all individual generators and therefore are unlikely to perfectly mitigate this risk.

Congestion management model mechanism modified for new generation investment and renewable energy zones

Under the basic congestion management model described above, rebates are provided to all scheduled and semi-scheduled market participants, with the possible exception of storage and load who would be better off without the rebate given it may be negative.

This does not solve a key problem in the existing regime – that of incentives to invest in efficient locations. Under the current regime, the incentives to invest in inefficient locations arises due to regional pricing, which ignores the fact that the marginal cost of congestion varies within a region. Under the congestion management model, the inefficient investment incentives arise because new connecting generators receive the rebate.

In order to address this concern, a modified version of the congestion management model is to charge all scheduled and semi-scheduled generators the congestion management charge (as per the basic model) but limit receipt of the rebate to:

- incumbent generators, as their investment decisions have already been taken and so there is little possible efficiency gains from withholding the rebate. As with the basic congestion management model, described in this will limit the disruption of the change to the access regime.
- new entrant generators that connect to, are foundational to, and contribute towards the cost of, a REZ.

That is, new entrant scheduled and semi-scheduled generators that are either not foundational to a REZ, or do not connect inside a REZ, would not receive a rebate.

Given that the rebate to each individual generator is a share of the total congestion management charge that arises from all generators, excluding some generators from the rebate will leave more for others. This will provide a strong signal to connect within, and contribute to the cost of, the REZ, because they will have a congestion risk management tool in the form of a rebate.

Those generators connecting late within a REZ, or outside of a REZ, will face exactly the efficient price signal in investment timescales, inclusive of the marginal cost of congestion, but will be less able to manage the risk of congestion because they do not receive the rebate. As such, the model allocates the risk of congestion (which is an inherent feature of any appropriately sized transmission network) to those new generators who did not contribute to the cost of the REZ infrastructure.

This model would have all the benefits of the basic congestion management model, while addressing the incentives for inefficient investment.

Table 6 Assessment of CMM modified for new generation investment and REZs

Objective	Assessment
Efficient congestion management signals in operational timeframes	Because all market participants would face the marginal cost of congestion via the congestion management charge, efficient dispatch would be promoted.
Efficient locational signals in investment timeframes	By limiting receipt of the rebate to those generators that have contributed to the cost of the REZ infrastructure, the model can be used to influence investment at efficient locations. Foundational generators within the REZ can purchase access to the rebates through REZ auctions, which in turn manage the risk of congestion. Given that the rebate to each individual generator is a *share* of the total congestion management charge that arises from all generators, excluding some generators from the rebate will leave more for others. This will provide a strong signal to connect within, and contribute to the cost of, the REZ, because they will have a congestion risk management tool in the form of a rebate. Those generators connecting late within a REZ, or outside of a REZ, will face the efficient price signal in investment timescales, inclusive of the marginal cost of congestion, but will be less able to manage the risk of congestion because they do not receive the rebate.

Efficient signals for storage	As with the congestion management model, both efficient operation and efficient investment for storage will be promoted under the model, because storage will be exposed to the efficient price – the regional reference price less the marginal cost of congestion.
Ability for generators to manage risk	Foundational generators that connect within the REZ will be able to manage the risk of congestion through purchasing access to receive the rebate. As new non-foundational REZ generators and other new generators outside of REZs would not have access to the rebate, the *share* of the total congestion management charge rebated to each individual foundational REZ generator would not be as substantially diminished by new connecting generators. New connecting non-foundational REZ generators may face difficulty managing risks under this model. They will not receive refunds and therefore be exposed to basis risk without a risk management tool.

As with the congestion management model, we expect this model to be low cost, and likely quick, to implement, for both AEMO and market participants.

Furthermore, the risk of additional congestion would be borne by those that did not contribute to the cost of infrastructure required to alleviate it, because they would not receive the rebate.

Variation – Congestion rebates for new interconnectors to be auctioned

One possible variation on this model is to apply a special regime to new interconnectors for the purpose of determining who receives congestion rebates. When a new interconnector comes online, the associated congestion rebates could be allocated to generators in accordance with the outcome of a tender or auction process. Auction proceeds would be used to offset transmission use of service (TUOS) charges paid by customers. Consistent with the proposed treatment of REZs, this approach would enable the costs of interconnector investment to be shared between customers and the generators that wish to use the assets. Under this model:

- *Incumbent generators* would automatically receive congestion rebates whenever they are affected by congestion, except where the congestion arises on a new interconnector. To be eligible to receive congestion rebates in respect of a new interconnector, it would be necessary to purchase the rights via auction.

- *Foundational REZ generators* would automatically receive congestion rebates whenever they are affected by congestion, except where the congestion arises on a new interconnector. To be eligible to receive congestion rebates in respect of a new interconnector, it would be necessary to purchase the rights via auction.

- *Generators connecting to the REZ after establishment* would not automatically receive any congestion rebates. To be eligible to receive any congestion rebate, whether in respect of a new interconnector or elsewhere on the network, it would be necessary to enter into an arrangement to purchase the rights.

- A design choice would need to be made about whether *new connecting generators outside the REZ* are eligible to receive an automatic allocation of rebates. If they are given rebates, it would be necessary to consider how to establish locational signals. For instance, a connection fee could apply – see the connection fee/CMM hybrid model. Either way, to be eligible to receive congestion rebates in respect of a new interconnector, it would be necessary to purchase the rights via auction.

At a conceptual level, this approach would be similar to grandfathering the current transmission network, and applying LMPs/FTRs to new infrastructure. A further design choice would be to extend the obligation to purchase rights to congestion rebates (essentially FTRs) to all new intra-regional investments as well as interconnectors.

There is potential for this model to be complex due to the need to identify which constraints have been affected by a given upgrade. The ESB is continuing to explore the feasibility of this model.

Locational connection fee

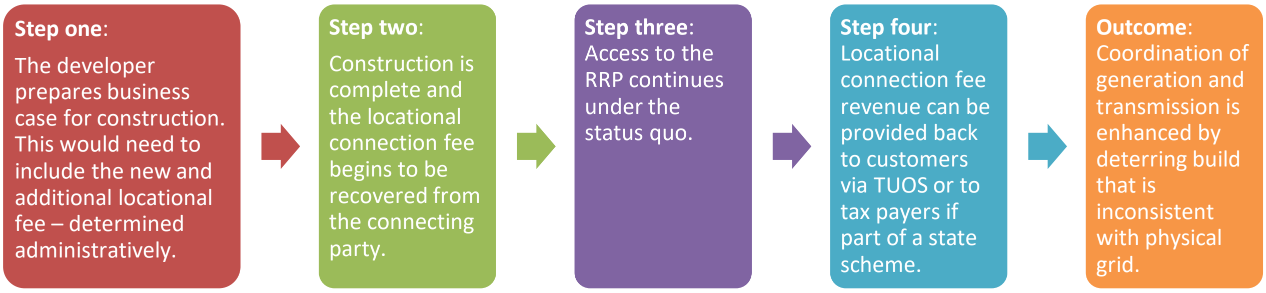
The ESB has developed a locational connection fee model that could provide a stepping-stone towards the long-term, whole of system access solution of locational marginal pricing and financial transmission rights. This model is designed to avoid some of the perceived problematic elements of the LMP/FTR model; namely, managing fluctuations in LMP and FTR prices over time, and the impact that this has on electricity contracts. It would also avoid the need for grandfathering arrangements as it would only be applicable to new entrants.

This model will charge new connecting generators a fee upon connecting to the grid. Locational connection fees and charges are not new to the transmission access debate. The connection fee idea is also a conceptual extension of the Connection access protection model from the interim REZ consultation paper.

The model, while in the early design phase, could work as follows:

- The connection fee would be an additional locational fee calculated at the time of the connection application - potentially based on alignment with the ISP and/or a forecast of congestion.
- It is expected that the fee would be determined administratively, likely by AEMO, based on an agreed methodology in a guideline, procedure or the rules. The fee could reflect a specific time horizon that could coincide with the implementation of the long-term access solution.
- The connection fee can be calculated based on one of two options:
    - The net present value of the expected marginal cost of congestion caused by a generator connecting to the grid at a particular location, over a defined period.
    - The net present value of the efficient cost of transmission infrastructure required as a consequence of a generator connecting to a particular point on the transmission network.
- The absolute level of the fee and levels of differentiation could be determined NEM-wide or specifically for state-based REZ deployment. There would be a trade-off between the accuracy of the locational signal and the simplicity of the process used to calculate the fee.

Figure 21 Indicative overview of a connection fee process.



The figure above highlights that the locational connection fee would be calculated before generation is built, and therefore will be considered in the business case for development. This provides an incentive for developers to locate at points on the grid that minimise the cost of the connection fee, which would also be locations with sufficient forecast hosting capacity.

Incentives for generators to locate in areas of the grid that have forecast sufficient hosting capacity will, in the long run, help to ensure that transmission infrastructure is used efficiently. Connecting parties who choose to locate in areas with a high connection charge will, through payment of the charge, contribute to offsetting the costs of any transmission investment needed to improve their access outcomes.

A principle for the fee would be to address the imbalance in which transmission is increasingly being built to meet developer requirements, but consumers pay under current arrangements. The locational connection fee could be designed to recoup some funds back to consumers.

The revenue received from the locational connection fee could be used in a number of ways, including:

- Offsetting consumer TUOS charges
- Provide ongoing financial access for foundational REZ generators
    - Note that if this approach was taken, the cost of transmission is no longer shared between generators and consumers.

Given that the NEM planning regime would have already planned for an efficient level of physical access, it is proposed that best practice would be to return revenue to customers.

Impact on new generation investment and renewable energy zones

Any fees paid through an auction or tender round would be paid by new generation investment in a REZ. The auction process would determine this fee. The value of being a foundational generator is likely be higher if it was known that higher fees would be payable later to locate outside the REZ or try to occupy the REZ as a late joiner given that these will likely have a more significant impact on network congestion. In this way, a locational connection fee that penalises non-optimal location will help establish value inside the REZ and differentiate the product (space in the REZ) that is being auctioned.

A key challenge will be to address the role and complementarity of generation types so that the design of fee does not inadvertently impair solutions to security and reliability issues being delivered through market responses and other NEM 2025 reforms.

Assessment of the model

This section examines the results of a detailed assessment of the locational connection fee model against the objectives. A summary of all the models rated against each other is in Table 7.

Table 7 Assessment of locational connection fee

Objective	Assessment
Efficient congestion management signals in operational timeframes	The locational connection fee is calculated and applied at the time of investment and would not provide price signals in operational timeframes. It therefore does not provide efficient incentives for a generators to manage congestion.
Efficient locational signals in investment timeframes	The locational connection fee model will provide an investment signal before the asset is built that reflects the ISP and congestion forecasts and will aim to encourage investment in optimal locations. The connection fee will vary depending on the impact that a given generator is forecast to have on network congestion by connecting at a given location. Therefore, connecting generators will face lower fees when connecting in areas of the network with sufficient capacity to host new generation output. It is important to note that a limitation of this model is that the accuracy of the locational signal is dependent on the quality of the forecasts. This task is likely to be more challenging the longer that the model is required to be in place before a move to long-term access reform. For example, forecasts of congestion are much more likely to be accurate within ten years than over the life of a generator.
Efficient signals for storage	It is unlikely that locational connection fees would be able to create efficient incentives for storage to locate. It will not be possible to predict at the time of investment whether storage will cause or alleviate constraints on the network and therefore it will be very challenging to calculate a connection fee. Similar to generation, this option does not create any incentives for storage to relieve transmission congestion in operational timeframes. Furthermore, it does not provide disincentives for storage to cause congestion in operational timeframes.
Ability for generators to manage risk	Under the locational connection fee model generators will continue to bear volume risk and have no direct congestion risk mitigation tools for operational timeframes. Similar to the status quo, generators would continue to not bear basis risk as they would continue to be paid the regional reference price.

The ESB's preliminary view is that a locational connection fee dependent on an administrative forecast of the future cost of congestion is likely to improve locational price signals in investment timeframes. However, connection fees, by definition, will not provide efficient price signals in operational timeframes for generation or storage and are unlikely to be able to provide efficient locational signals to storage.

Charging generators for their use of the transmission network

Under a generator transmission use of system (G-TUOS) charge model, generators would be required to pay an ongoing charge that reflects the relative cost of providing transmission infrastructure at a given point on the network. The charge would be designed to provide a locational signal for generators such that they internalise the network costs associated with maintaining the generator reliability standard at their chosen location.

Consideration would need to be given to what proportion of TNSP revenue would be recovered from generators. Both generators and load benefit from the transmission network and so it is difficult to precisely assign costs between them. The most straightforward method of allocating costs may therefore be a fixed proportion of TUOS revenue, such as a 50/50 division.

Alternatively, load could continue to pay TUOS charges for all the network capacity that is required to meet load reliability standards. Generators could then pay the incremental costs of any additional capacity that was required to meet the generator reliability standards, above and beyond what is required for load. We would need to consider how to determine the capacity of the network that is used to meet load reliability standards, relative to generator reliability standards, which may be difficult.

Once the appropriate split between load and generators is determined, a G-TUOS approach typically uses an administrative process to calculate a locational factor that is used to apportion transmission costs between generators. There are a range of different methodologies that could be used to calculate the locational factors, including by calculating long run marginal cost (using the Integrated System Plan as a baseline), incremental flows and flow tracing.[61] Ideally, the methodology should seek to reflect cost of transmission or congestion at connection point (or a zone within a region).

It would also be necessary to establish a charging methodology to define the metrics used to calculate generators' charges – for instance, whether generator bills are calculated by reference to the capacity or output-based factors, and whether there is a fixed portion. Charges would be recalculated annually as part of the transmission charging process.

Consideration would also need to be given to the appropriateness and form of any transitional provisions to apply to existing generators.

While the G-TUOS model is in the early design phase, the following example demonstrates a possible approach to how generator TUOS could be calculated.

[61] See AEMC (2011) Transmission Frameworks Review First Interim Report, Appendix C.

Box 5 Example – Generator TUOS

The administratively calculated cost recovery calculated from applying the AER's revenue determination permitted a TNSP to recover $600m in total TUOS for a given year. The regulatory framework under a G-TUOS model specifies that 50 per cent of TUOS is to be recovered from load, and 50 per cent from generation. The generators' component of TUOS is split between four generators based on a locational factor and their capacity.

Generator	Capacity	Rate	Charge
A	100MW	$350k/MW	$35m
B	300MW	$150k/MW	$45m
C	250MW	$200k/MW	$50m
D	700MW	$214k/MW	$150m
TOTAL			$300M

In this example, GTUOS charges are recalculated annually as part of the transmission charging process. Internationally the requirement for generators to pay for the transmission network is typically combined with either a physical or financial firm access framework. For example, the G-TUOS approach applied in Great Britain currently provides generators with a defined level of financial access in return for paying TUOS charges. In essence, when generators are constrained off due to congestion on the network, consumers fund payments to generators to mitigate the impact of not generating. If we were to adopt such an approach, we would need to assess the expected reduction in TUOS to consumers from G-TUOS compared to the payments to generators when constrained.[62] Alternatively, G-TUOS could be paired with a generator reliability standard that does not allocate firm access to any specific generator.

Assessment of the model

This section examines the results of a detailed assessment of the G-TUOS model against the objectives. A summary of all the models rated against each other is in Table 8.

Table 8 Assessment of G-TUOS

Objective	Assessment
Efficient congestion management	Due to the timeframe that G-TUOS would be set on (likely annually) and the administered basis of the charges, this option does not appear to be able to provide

62 An example of constraint payments in the UK is included in their monthly balancing services summaries. https://data.nationalgrideso.com/backend/dataset/f89a12fc-94ef-4a09-bce2-c094c7212e1f/resource/e46d25a4-0c6e-4761-b677-541ed12e7f33/download/mbss-november-2020.pdf

signals in operational timeframes	efficient price signals in operational timeframes and therefore will not efficiently manage congestion.
Efficient locational signals in investment timeframes	The G-TUOS charges would provide some locational price signals to generators and storage. There is a risk that these price signals may not be entirely efficient or accurate. The generator will only receive efficient price signals to the extent that the administratively determined charges can be calculated to reflect the forward cost of congestion, and the generator can predict the administratively determined charges at the time it makes its investment decision.
Efficient signals for storage	It is not clear that G-TUOS would be able to create efficient locational signals for storage. At the time G-TUOS is calculated, it would not be known whether storage would operate in a way cause or alleviate constraints on the network. This option does not create incentives for storage to operate in a way that relieves transmission congestion.
Ability for generators to manage risk	Under the G-TUOS model, generators continue to bear volume risk and have no risk mitigation tools, unless paired with a firm access framework. This is not an improvement from the status quo in regard to risk management tools. While this model does not impose basis risk on generators, it does result in risks to generators of the administratively determined G-TUOS charges changing over the life of the generation investments. For example, similar to the current MLF regime, the resetting of G-TUOS charges on an annual (or 5 yearly) basis represents an unhedgeable risk to generators.

The G-TUOS model has the potential to provide some locational signals to generators in a way that does not change the wholesale pricing framework. It also has the potential to allocate some costs from consumers to generators for use of the network, in turn re-balancing the allocation of risk associated with transmission investment. However, there are a number of cons associated with the model. Assuming the G-TUOS costs are set administratively and vary periodically they will be difficult for generators to mitigate the risk of unpredictable changes in these costs. The model also does not appear to provide efficient bidding signals to manage congestion in operational timeframes.

Combinations of the models

Table 3 of the main document (see Chapter 5, Part A) presents the strengths and weaknesses of all the models against the objectives described above. Given that each of the models has different strengths and weaknesses it is worth considering if the models could be combined into a hybrid approach to utilise the strengths of multiple models.

Of the models discussed here, the congestion management model is the only model that provides efficient congestion management signals in operational timeframes, which has been highlighted as a priority in the medium term. We therefore focus on combinations of this model and G-TUOS or connection fees here.

Congestion management model and connection fee hybrid

The congestion management model and the connection fee models would be likely to complement each other particularly well. The connection fee model would provide locational signals in investment timeframes, while the congestion management model would provide efficient congestion management signals in operational timeframes. Importantly, the combination of these models would be internally consistent because the fixed up-front nature of connection fees (targeted at investment decisions) will not crossover or 'double up' with the dispatch by dispatch interval price signals (targeted at operational decisions) provided through the congestion management model.

This combination would also appear to provide an effective means to facilitate REZs. The changes to the congestion management model to facilitate REZs described in Section 11.1 above could be applied with one additional change. This would be to allow generators connecting outside of REZs to connect *and* be granted congestion management refunds but charge them a connection fee. The connection fee would need to include calculations of the extent to which the connecting generator would be likely to cause congestion for foundational REZ generators. The outcomes and likely incentives of such a hybrid approach are provided in Table 10.

Table 9 Outcomes and incentives under CCM/connection fee hybrid

	Receive access rights?	Pay connection fees?	Incentive
Foundational generators inside the REZ	Yes – through participation in the REZ auction	No, but do pay the REZ auction price.	Incentive to locate inside the REZ to receive access rights which are unlikely to erode over time.
Generators connecting to the REZ after establishment	No.	No.	Disincentive to connect. Generators would receive no access rights and therefore be exposed to their LMP with no risk mitigation tools.
Existing generators outside the REZ	Yes.	No.	Are exposed to the LMP to provide efficient congestion management signals. No connection fee applies as have already connected. Receive congestion management refunds to make them financially indifferent to the reform.
New connecting generators outside the REZ	Yes.	Maybe – depending on where the generator is seeking to connect.	Discouraged from investing in locations which are likely to be congested in the future through connection fees. Are exposed to the LMP to provide efficient congestion management signals but receive congestion management refunds as a result of paying the connection fee.

The hybrid model meets most of the objectives. Its primary weaknesses are potential inaccuracies in the administratively determined connection fees, and instances where congestion management refunds do not provide effective risk management tools.

Table 10 Assessment of hybrid model

Objective	Assessment
Efficient congestion management signals in operational timeframes	Congestion management under the hybrid approach is provided through the expose of participants to the LMP via the congestion management charges under the CMM. Exposure to the LMP provides efficient signals for generators to bid reflective of their underlying costs and therefore results in efficient dispatch and congestion management.
Efficient locational signals in investment timeframes	Locational signals in investment timeframes under the hybrid approach are provided by the connection fees. To the extent that the administratively set connection fees can be calculated accurately, these will provide efficient locational investment signals.
Efficient signals for storage	Storage under the CMM is exposed to (and benefits from facing) the LMP and therefore would not be required to pay or receive congestion management refunds under the hybrid approach. With no congestion management refunds, the exposure to the LMP results in storage facing efficient price signals in operational and investment timeframes. With storage already facing efficient locational investment signals, there is no need under a hybrid model for storage to be charged a connection fee.
Ability for generators to manage risk	The hybrid model would help market participants manage risk. In particular: • The congestion management refunds within the CMM help alleviate generators' exposure to price risk • The CMM removes volume risk through the provision of LMPs, and • With connection fees known prior to investors committing to specific projects, they are able to assess whether they wish to proceed with the investment on the basis of the connection fee.

Alternative hybrid approach - Congestion management model and G-TUOS

As set out in Section 3.2.4, the development of a potential G-TUOS framework is in the very early stages and G-TUOS can take a wide variety of forms. It is therefore difficult to assess whether it could be combined with the congestion management model. Several preliminary conclusions can however be drawn:

1. G-TUOS which applies fixed charges to generators instead of energy (kWh) or demand (KVa) is more likely to be compatible with the congestion management model. The latter types of charges provide price signals in operational timeframes which would 'double count' the LMP based price signals in the congestion management model.

   Fixed charge-based forms of G-TUOS targeted at sending locational signals about the upcoming costs of congestion may closely resemble the connection fee model. With the main difference being that connection fees are set and locked in at the point of connection, while G-TUOS would be updated annually. These would therefore be compatible with the congestion management model and the main choice would be an evaluation of this framework against the connection fee framework regarding which would provide better locational investment signals and allow market participants to manage risk.

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