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Dear Energy Security Board members,

ESB POST 2025 MARKET DESIGN OPTIONS – A PAPER FOR CONSULTATION 30 APRIL 2021

Australia's transition to renewable generation- happening at a breathtaking pace - is a tremendous achievement for all. However, a renewable dominated power system still requires physically dispatchable generation to maintain reliability, both during this transition and beyond. Similarly, consumers still expect that their energy services will be reliable, and delivered at the lowest cost.

However, signals in the current market framework do not support dispatchable capacity into the future, and if we fail to address this we risk reliability problems, price shocks and sustained government intervention to manage these problems.

We propose, a physical retailer reliability obligation (PRRO) which will help to physically stabilise the power system and keep it reliable and affordable for consumers as we bring forward new renewable and other capacity investment.

This mechanism can supplement the current market by:

- placing explicit accountability for reliability on retailers and generators alike,
- supporting much needed investment in plant to maintain stability over time as new renewable resources enter the system, and
- providing a stronger and clearer dispatchable investment signal.

A physical RRO can supplement the current market by placing continuous physical obligations on participants, and be based on actual consumption and generation. Such a mechanism will result in the lowest cost for consumers.

We have provided considered recommendations to solve the problem at hand and welcome ongoing dialogue. Should you have any questions, please contact Sarah Ogilvie on 03 8628 1805 or sarah.ogilvie@energyaustralia.com.au.

Yours sincerely,
Ross Edwards, Markets Executive

Executive Summary

- We are experiencing a rapid decarbonisation of the energy sector in Australia. Older, thermal based plant is being replaced by newer, largely renewable, forms of generation. This has been driven by multiple factors relating to policy, technology and commercial drivers.

- The rapid pace is a tremendous achievement, but in order for the transition to progress smoothly we must meet reliability and affordability requirements of consumers.

- To do this, we need the current system working to achieve reliability and affordability, while we build the new one. This requires:
  - existing assets to remain reliable until they are no longer needed by the power system,
  - adequate signals to invest in the mix of technologies and capacities that are needed to provide the reliability services our customers need, and
  - entry and exit of capacity are timed to avoid shocks to the system and customer bills.

- The current market framework will not provide for this on its own, and needs an additional mechanism focused on actual reliability outcomes. Such a mechanism will enable investment in assets to smooth out reliability and price shocks as the system embraces renewables over the next decade and beyond. Its primary focus is on ensuring reliability at the cheapest cost to consumers, and as such, can work independently of specific government support for new investments.

- Modifying the RRO to make it a capacity certificate mechanism will do this by:
  - making retailers responsible for the reliability of their load on tight supply and demand days
  - making generators responsible for the reliability of their generation on tight supply and demand days
  - providing a stronger and clearer investment signal that enables the market to invest in the right amount of dispatchable capacity to meet reliability expectations. The length of the price signal is a design feature that needs to be further explored.

- The current ESS rule changes are sufficient to maintain system security, but they must be progressed swiftly and accompanied with significant demand information to give investor’s certainty.

- Transmission and access reform should emphasise the importance of NEM-wide planning and look to find practical solutions to problems that exist after other market changes have been implemented.

- Regulatory changes to accommodate Distributed Energy Resources need to start at where the current market offerings are deficient and be driven by what customers want.

Section 1: Resource Adequacy Mechanisms and Thermal Exits

Key points:

- EnergyAustralia is committed to ensuring resource adequacy to facilitate the energy transition. This transition is happening much faster than anyone anticipated. We are accountable to our 2.4 million customers, who expect us to protect them from price and reliability shocks arising from the exit and replacement of large baseload coal plant.

- Owners of generators know the reliability of their plant better than anyone else, and retailers understand the movements of their load better than anyone else. This thinking underpins the current RRO framework. Modifying this to:

    - create new **'physical' capacity,** certificates, would support explicit obligations on owners of generation and storage plant to have capacity available when it is needed, and for retailers to contract this capacity to cover their expected and actual load requirements.

    - have these obligations **'always on'** for liable entities. This places the risk of reliability shortfalls onto retailers and generators, not only for the volume of capacity that is needed, but at the times when the system will be under the most stress.

    - change the **compliance obligations to focus on actual supply outcomes**. In combination with the above, retailers and generators should be held responsible for their actions on the day and how they contributed to system-wide outcomes.

- These modifications will stabilise the current market framework to safeguard reliability and affordability for consumers as we integrate more renewables.

- It does this by providing an explicit signal for dispatchable investment. The current market signal for investment is distorted by non-physical derivatives and an abundance of new renewable energy. The term for the forward time frame for price discovery is a design feature to be further explored. In our market we have seen where there are clear targets and objectives commercial entities have sought to find the right balance between risk appetite, contract term, cost of capital and new investment. The RET is a successful example of this with a range of commercial structures being pursued from merchant investment through to whole of life asset contracts, without an explicit design feature for long-term contracting.

- Alternatives to this physical RRO fall short of providing a balance between investment certainty and low costs for consumers. 'Do nothing' is also not a realistic option.

The market undergoing unprecedented technological change

The unprecedented growth in renewables is pushing wholesale electricity prices to the lowest they have been since the NEM began, including new and sustained periods of negative prices. This is a result of investments in grid-scale renewables as well as behind the meter technologies making demand from the grid, as well as supply availability, less predictable and more weather dependent. Reduced revenues for thermal generators are accompanied by an increasing need for flexibility and ramping over shorter time periods. This places a significant challenge on the technical performance of coal-fired power generation. These combined dynamics bring a risk of deteriorating plant reliability, with exits from the market that are potentially much faster than expected by system planners, and by investors in new plant. The business case for new firming capacity, which is critical in enabling much higher amounts of renewables and to replace exiting thermal plant, is also being challenged.

The current market design is unlikely to deliver affordability in the long term

Once thought expensive, zero marginal cost renewables are causing a marked, and celebrated, decline in wholesale spot prices. There is, however, a reluctance to accept that these lower prices will drive out existing older thermal generation; thereby increasing spot prices. A period of higher spot prices is needed under the current frameworks to encourage investment in replacement capacity.

Some doubt whether our current market framework can provide price signals and cover the 'missing money' required to invest in capital-intensive 'dispatchable' plant, which is now critical to replacing exiting coal plants and complementing more renewables. This doubt may actually be derived from discomfort in generators setting very high prices at times of scarcity, particularly as customers have little ability to respond to such high prices by reducing demand in real time. It is for this reason we consider prospects for incremental change are unrealistic (and likely ineffective), and the ESB is correct in canvassing more substantive options for policy-makers' consideration.

The practical challenge then becomes reforming the National Electricity Rules (NER) in a way to create signals for investment in reliability while at the same time accommodating different jurisdictional preferences regarding the pace and nature of the renewal of the power system. Departures from NEM-wide reliability settings and associated price signals will have distortionary impacts on investment across jurisdictions, and potentially form policy gaps, which all elevate the risk of customers wearing higher costs than necessary over the longer term.

The scale and nature of reliability risks are changing rapidly

Generation resource adequacy has, until recently, typically been a concern at times of maximum demand, with challenges mainly around forecasting temperature and other underlying consumption drivers. These 'times' were generally seasonal.

Reliability risks are now increasingly supply-side, given the growing scale and locational diversity of variable renewable sources, network constraints, extreme or unpredictable weather events and deteriorating performance of aging thermal assets. Weather, network and locational issues also arise in variability of supply from distributed energy resources. There is also an open and important question on whether DER technologies, and the electrification of transport and industry, will assist in enabling active demand to help address reliability concerns, or will make them worse. These reliability risks also occur more frequently.

Signs of this stress are starting to show now, with the power system having only 28 per cent of its energy generated from renewable sources.[1] We need to solve this problem now, before we can shift to 80 to 100 per cent renewables.

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[1] Clean Energy Report | Clean Energy Council

Of all sources of demand and supply fluctuation, the most prominent concern at present is the risk of sudden exit of coal capacity, given the status of the transition, and that these events will have the largest discrete, and lasting, impact of all other factors.

Reliability concerns relate to the capability of, and trust in, the current regulatory and market framework to effectively signal resource scarcity associated with coal plant exit, such that investors can bank on this signal with replacement generation. Importantly, there is a lack of trust that this generation will be ready well ahead of when it is needed. Related to this, governments and the wider community can never have certainty that enduring high wholesale spot prices in the interim will result in the market delivering replacement capacity.

We need a bankable price signal to support reliability

Market settings will be successful where reliability in the system is maintained while new technologies are replaced for old. Specifically, we need an orderly transition where:

- existing assets to remain reliable until they are no longer needed by the power system,
- there are adequate signals to invest in the mix of technologies and capacities that are needed to provide the reliability services our customers need, and
- entry and exit are timed to avoid shocks to the system and customer bills.

A new price signal to support dispatchable services is required and it needs to be bankable. This would encourage investment in existing assets for reliability; and set a long-term price signal for new dispatchable resources. Such a reliability signal will be needed through the transition, and afterward, when our system is largely supplied by zero marginal cost renewables.

The current RRO attempts to bolster the investment environment. However, it was originally intended to do this on the presumption that derivative contracts were generally backed by dispatchable capacity or demand response. This presumption has not held and the 'financial' nature of the current RRO, coupled with a fast injection of government backed renewables is distorting the energy price, and hence relying on the financial market for dispatchable investment is not working. Consequently, the RRO has been triggered in SA twice and triggered in NSW but without any dispatchable investment coming in as a result. Investments have only taken place on the back of government support. The NSW Electricity Infrastructure Roadmap framework also provides for a separate 'firming' pillar.

The existing RRO can be amended to provide this price signal

We consider that three amendments to the design of the RRO can be made to achieve its original intended objectives, and provide governments confidence that reliability and affordability can be maintained without disruption:

- Modifying the range of **eligible contracts to be explicitly based on 'physical' capacity,** rather than financial 'firmness'. This would be supported by explicit obligations on owners of generation and storage plant to have capacity available when it is needed, and for retailers to contract this capacity to cover their expected and actual load requirements. This maintains the essence of the current RRO design, namely that the owners of generators know the reliability of their plant better than anyone else, and retailers understand the movements of their load better than anyone else.

- Rather than rely on obligation 'triggers', **these obligations should be 'always on'** for liable entities. This places the risk of reliability shortfalls onto retailers and generators, not only for the volume of capacity that is needed, but at the times when the system will be under the most stress. Removing the current RRO triggers shifts 'forecasting' risk from AEMO and the AER onto participants who are better placed to assess and mitigate this risk.

- Change the **compliance obligations to focus on actual supply outcomes**. In combination with the above, retailers and generators should be held responsible for their actions on the day and how they contributed to system-wide outcomes. This ensures that not only the required investment takes place, but that capacity is available to supply in real time.

The design parameters of this physical RRO can also accommodate jurisdictional preferences on reliability settings and investment incentives. This would be done via several means:

- requiring retailers to procure certificates to cover higher proportions of their load requirement e.g. 90 or 100 percent

- calibrating penalties for non-compliance. The 'default' settings would reflect the economic value or opportunity cost of reliability (i.e. VOLL, current market price caps etc) as this provides the 'right' signal for the capacity that is needed

- prescribing triggers or compliance windows i.e. pre-determining the trading intervals where entities must guarantee coverage of their physical supply and demand.

The term for the forward time frame for price discovery is another design feature to be further explored. As per the current RRO, we suggest using a Market Liquidity Obligation (MLO) on generators to start the price discovery signal for reliability. This MLO should reflect capacity assumptions in AEMO's ESOO and can occur anywhere between 5 to 10 years out. In our view, a forward market for reliability certificates extended out to 5 years is a practical limit for price discovery. Retailers are best placed to build on their current risk management capabilities to determine when to purchase certificates given the prevailing physical certificate price, capacity forecasts, predictions of tight supply and demand days, and predicted load movements on such days. With retail prices generally set by a market on a year-by-year basis, we do not believe it is necessary or desirable to enforce a longer-term purchasing commitment on retailers. However, we recognise some oversight of contracting behaviour and levels is desirable, and we suggest contracting positions should be reviewed by AEMO one year out, or as needed to support AEMO's decisions regarding RERT procurement.

In our market we have seen where there are clear targets and objectives, commercial entities have sought to find the right balance between risk appetite, contract term, cost of capital and new investment. The RET is an example of this, with a range of commercial structures being pursued from merchant investment through to whole of life asset contracts. This has been the most successful mechanism to drive new investment despite there being no explicit design feature for long-term contracting.

A further design element to consider is whether any specific introductory requirements, such as a fixed price period, should be introduced to support market confidence.

A physical RRO can supplement the current market and work alongside government investment schemes, if necessary

As noted earlier, amendments to the RRO to make it physical are squarely targeted at providing reliability at lowest cost to support the transition. It does this by providing a supplementary, and clearer, price signal for dispatchable investment to be available for periods of tight supply. A signal for dispatchable investment above the current market will show up in the physical certificate price only if the current market falls short. Therefore, the Market Price Cap and other market reliability settings do not need to be adjusted, as the mechanism only engages if the market predicts are credible supply shortfall. In this way, the current market settings still provide important signals for participants to show up on the day and respond to real-time supply and demand fluctuations.

A clear price for reliability, based off market participant's expectations and reflected in the price of traded certificates, should be used to support governments' decisions regarding underwriting for renewables and other forms of new capacity investment. Having a strong market signal should also help to minimise any subsidies required for firmed renewables or new capacity investment, if such investment is deemed necessary by government. Similarly, as new investments will also be required, through the MLO, to engage with the certificate market, it will integrate the underwriting and reliability obligations to keep the cost of retailer obligations for reliability as low as possible.

A physical RRO has advantages over alternative resource adequacy mechanisms

The physical RRO has inherent design features that make it preferrable to alternative resource adequacy mechanisms (RAMs), namely a 'triggerless' financial RRO, an operational reserve, and centralised capacity mechanism:

- It 'forces' the market to identify and solve reliability concerns. The nature and risk of reliability is changing. Market participants are best able to identify and manage this risk through their contracting decisions, including in reflection of the condition of their own assets and customers' load characteristics. The physical RRO also involves clear obligations to have capacity available when it is needed, in real time.

- The physical RRO specifically targets physical capacity to be delivered. Adjustments to the existing 'financial' RRO and the operating reserves model still rely on financial contracting, which is likely to provide a weaker incentive, as well as make it more opaque in terms of what capacity is required and will be delivered. For these reasons we do not consider the financial RRO or operating reserve will provide adequate transparency and confidence that generation and other capacity will be there when needed, and so minimise price shocks to consumers.

- Alternative 'centralised' capacity market models may give governments more 'visibility' by allowing them, or a central planning agency like AEMO, to directly determine the amount of capacity to be installed at a particular time, and even the specific technology type. However, this would rely on a central forecast of when the system will be under most stress.
    - While this may have benefits from an accountability perspective, it would likely encourage conservatism in forecasts. Costs to consumers would be higher than they would be under arrangements that push forecasting risk onto private entities, whose commercial model is based upon assessing and mitigating this risk on a daily basis.

- Experience overseas and domestically has consistently shown centralised capacity mechanisms to be the least efficient and highest cost method to meet reliability goals, primarily due to fallible forecasting and incentives to over-procure.

We support improved information flows relating to plant exits

We agree with the ESB's recommendations in terms of its immediate reforms around information provision on resource needs, including those that seek to de-risk the prospect of disorderly exit. The ESB should consider existing data that is collected for resource adequacy assessments in order to minimise burden on reporting entities, which would flow into any new or specific assessments prepared for the purposes of jurisdictional governments.

As it relates to the risk of disorderly exit, we support the provision of information and expert advice being provided to jurisdictional governments. This is complementary to RAMs mechanisms, in that providing even more clarity on the timing, scale and impact of exit will provide more investor confidence around business cases for new capacity, and in turn this should provide confidence to governments that replacement plant will be ready when it is needed to maintain reliability. This reporting and analysis should be elevated to the public domain and receive broad stakeholder scrutiny.

Ideally information flows should be two-way. That is, jurisdictional governments should be clear on their short-term policy actions and intentions over the longer timeframes that are relevant to private sector investment and market replication. This would include disclosing why certain decisions are made — political risk is higher and private investment will be hampered when government actions are far out of alignment with available evidence, particularly relating to system needs or community preferences.

There may be a role for AEMO in taking existing generator data and analysis e.g. from the MTPASA and ISP, and preparing ad hoc, targeted or more granular scenario-based assessments where there are considerable uncertainties and risks regarding system impacts. If AEMO already does not have powers to initiate this analysis, or is not obliged to conduct it in response to jurisdictional requests, it seems prudent to make this a feature of the relevant regulations.

The ESB should also be mindful of existing information flows between certain generator owners and jurisdictional governments who are already exploring risks in their own regions and communities in which they operate.

The need to amend notice of closure requirements is less clear

It is unclear why the ESB proposes to include mothballing in the notice of closure requirements and who would benefit from this. If the benefit is in providing AEMO better information on whether a plant can be called back on at short notice, this could be drawn from PASA information instead.

There are two situations which pose problems for the current notification and exemption process:

- a generator can currently 'mothball' and then permanently close without seeking exemption for an early closure (i.e. it effectively closes early while still complying with the 42-month notice period)

- the AER refuses exemption and the plant permanently closes anyway.

The ESB’s proposal to trigger an exemption application for mothballing deals with the first of these, however does not deal with the second.

The ‘New’ process elements identified in Figure 3 of the ESB’s appendix appear largely cosmetic i.e. the AER’s exemption process already appears to allow the provision of necessary information to the AER as well as a form of system impact assessment by AEMO. Presumably state governments can already access data and AER/AEMO analysis in determining whether and how to intervene. The value-add in the ESB’s proposal appears to be mandating higher information standards and provision for certain designated generators and in guiding state governments on their reactions.

In any case, additional oversight of closures would not be necessary where there are adequate incentives to keep in existing capacity where this can provide reliability to the system at least cost. Any incentives under a physical RRO type arrangement would also be less effective where existing plant owners are constrained in their ability to respond or are otherwise treated differently to new entrant firming capacity. Requiring generators to seek exemptions may actually encourage some owners to provide earlier closure notice than they really intend, with the option of extending closure dates. This might be to the detriment of the market and also AEMO in its planning role.

Furthermore, the ESB’s proposal around exemption requirements raises various implementation challenges. We would be concerned if any new requirements to seek exemption, alongside additional information provided to governments on the basis of generator commitments or forecasts, were translated into new compliance obligations on closure timing or availability. Again, this would alter incentives on the commitments that generators provide and their closure/ availability decisions.

Section 2: Essential System Services and Scheduling and Ahead Markets

Key Points:

- EnergyAustralia has been heavily involved in the Essential System Services (ESS) rule changes being progressed by the Australian Energy Market Commission (AEMC) and is supportive of the national proposals and outcomes seen to date. These include:
    - the addition of two new Fast Frequency Response (FFR) services to the existing suite of Frequency Control Ancillary Services (FCAS);
    - a new forward-looking and proactive framework for the provision and procurement of System Strength;
    - the assessment of market-based options to replace the mandatory Primary Frequency Response (PFR) obligation;
    - and deep-dive assessments showing an Operating Reserve (OR) to be unnecessary for system security purposes even under extreme ramping and unforeseen contingency event scenarios.
- Inertia Spot Markets are also strongly supported by the broader industry with implementation desired sooner rather than later. We and other members of the Australian Energy Council (AEC) are working on an inertia options paper to inform a rule-change proposal to facilitate this.
- In principle, we support the implementation of the Unit Commitment for Security (UCS) mechanism to maintain a secure system. However, we have strong reservations about using the UCS to alleviate constraints so that additional Variable Renewable Energy (VRE) can be dispatched for net market benefits. Although a sound economic principle, in practice, there remain many details and complexities to be worked through to ensure fair and robust practical application.
- Given the lack of time to pursue such analysis before final ESB P2025 recommendations, we support the AEMC taking carriage of any further exploration of a UCS as part of a detailed forward work programme post the planned disbandment of the ESB.
- Along with the majority of other industry participants, we strongly oppose extending the UCS into a more structured, ahead mechanism for dispatching all ESS via a System Security Mechanism (SSM). With additional, sharper real-time market prices and new investment frameworks efficiently delivering and scheduling ESS, there is no rationale for further complex and costly ahead-of-time coordination mechanisms to do so. We, therefore, recommend that the SSM not be pursued any further.
- We are also strongly opposed to extending the SSM into a fully Integrated Ahead Energy and System Services Market. This has been the subject of fierce industry opposition given its lack of convincing rationale, technical complexity and costs. Once again, we consider no further work on it should take place.
- Regardless of which ESS services ultimately result, we strongly encourage more ESS informational resources be developed. Greater transparency and detail on ESS demand and supply dynamics will result in more efficient ESS investment and faster ESS delivery.

Timely information provision will ensure efficient and rapid ESS investment

EnergyAustralia has been heavily involved with the P2025 ESS rule changes progressed by the AEMC to date. This has included providing technical insight and expertise as part of various Technical Working Groups (TWGs) and other industry fora. In general, we are supportive of the direction these nationally focused initiatives have taken. However, we consider a key additional action should be the development of additional ESS informational resources for market participants. In order to make the most efficient investment decisions and effect the quickest service delivery, information on ancillary service supply and demand dynamics will be required. A five-year AEMO ancillary services outlook that replicates existing modelling for energy would be a welcome and useful addition to support this outcome. Beyond this general point, the following provides further detail on our thinking on each of the ESS rule changes.

Fast Frequency Response is supported

We consider that the industry is already in or beyond the Australian Energy Market Operator's (AEMO's) Step Change Integrated System Plan (ISP) scenario. We, therefore, agree with the AEMC that there will likely be a material cost increase in R6 Frequency Control Ancillary Services (FCAS) requirements over time. Although holding some reservations about the lack of a comparative Cost-Benefit Analysis (CBA) to assess alternate solutions that could address this issue, we consider an FFR market to be a relatively low cost and low regrets solution. That is, in producing net economic benefits compared with a 'do-nothing' alternative, being relatively quick and low cost to implement, and not impeding the development of other longer-term solutions such as inertia markets.

The new System Strength Framework is strongly supported

We strongly support the emerging system strength framework that has been developed in close consultation with the industry. The new supply-side planning standard, demand-side minimum access standards and the system strength mitigation requirement will go a long way toward correcting deficiencies with the current 'do no harm' and system strength frameworks. That is, by promoting a more streamlined and faster connections process and providing the efficient level of system strength via a proactive combination of network augmentation, generator contracting and re-tuning solutions.

Market-based Primary Frequency Response should replace the mandatory obligation

Early reports on the National Energy Market (NEM) frequency distribution have shown a marked improvement in frequency performance since the implementation of the Mandatory PFR rule change in mid-2020. However, this has occurred with only those generators above 200MW having applied the new, tighter PFR settings. Moreover, the incremental benefit in frequency performance has decreased as more units have been included. This clearly demonstrates that imposing costs on all generators via a mandatory PFR obligation is:

- not required to effect an improvement in NEM frequency performance, and
- much less efficient than a spot market approach that would provide the optimal level of PFR based on the marginal cost of procurement from machines that supply the most effective frequency response.

We and other members of the AEC have provided advice to the AEMC on alternative PFR solutions that could replace the mandatory PFR rule when it sunsets in 2023. For example, double-sided causer pays arrangements are being investigated via a joint Australian Renewable

Energy Agency (ARENA), AEC and Intelligent Energy Solutions project. This advice has been well received and we are, therefore, highly supportive of the AEMC's continued investigation of alternative market-based solutions that has resulted.

Operating Reserves are not required for system security and are not supported

We have long-held concerns about the rationale of an ESS OR. Early arguments focused on the possible benefits of using an OR to signal the value of missing ESS. However, with system strength provided under the new framework; with FRR and PFR provided by new markets; and inertia proposed to follow the same route, the case for an additional ESS value signalling mechanism has collapsed.

Despite this, proponents have suggested that an OR should be advanced on the basis that it may be required to manage:

- ramping requirements in future scenarios of extremely high renewable energy penetration, and

- shortfalls in actual ESS provision that result from differences in the planning and operational timeframes, or ESS gaps that may appear before other ESS procurement solutions are implemented in the next few years.

A recent analysis conducted by Endgame Economics at the behest of the AEMC has undercut these arguments. Using scenario-based, power systems modelling, the analysis shows that an operational reserve would not be required to resolve extreme and unforeseen ramping and unexpected contingency events, even in situations of high renewables penetration. Although noting necessary limitations and simplifications with the modelled approach in a related industry deep-dive session, industry experts were confident that there was sufficient evidence presented that an OR is unlikely to be needed for ESS purposes[2]. Further, that in most cases, the system was capable of responding appropriately to even extreme eventualities as is, or would be able to do so in concert with existing Network Support Arrangements (NSAs) and the mooted UCS mechanism.

We concur with this assessment and, therefore, see no reason for an OR to be considered any further as part of the P2025 ESS Market Design Initiative (MDI).

Inertia Markets should be a priority development

In contrast with industry assessment of the value to ORs, responses to the AEMC's FFR options paper highlighted strong support for a mechanism to value inertia. Further, that such a mechanism is desired sooner rather than later. It is, therefore, surprising to see inertia markets development placed in the next reforms stage.

We agree that further work is required to design and implement inertia markets. However, we consider this should be a priority development in preference to working on Scheduling and Ahead Markets (SAMs) initiatives. That is, given its clearer rationale, stronger industry support and higher expected benefits. To this end, we and other members of the AEC are working on an inertia options paper to inform a rule-change proposal and expedite development. We look forward to sharing this paper with the ESB and AEMC in due course.

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[2] See AEMC notes of the session available from the Reserves and Ramping rule change web page.

A Unit Commitment for Security may help security outcomes but caution is required

Except for using the UCS for some specific security applications, we and the majority of the industry are strongly opposed to the SAMs proposals. In principle, we support the implementation of a UCS mechanism to maintain a secure system. This is on the basis that it should help to streamline and better operationalise AEMO's directions and interventions processes. That is, by:

- obviating the manual collection of information, assessment and identification of resource gaps;
- increasing the transparency to market by showing potential gaps and providing the timeframe for the market to respond; and
- providing consistent application and pricing of direction and intervention events.

However, we have strong reservations about using the UCS to alleviate constraints so that additional VRE can be dispatched for net market benefits. Although a sound economic principle, in practice, there remain many details and complexities to be worked through to ensure fair and robust practical application. These include:

- **Costs and benefits** – Market benefits need to be assessed against the desired baseline of VRE output, but it is unclear what this baseline should be. Similarly, it is unclear whether the impact of being 'dispatched down' as a result of UCS intervention should be included in cost calculations.
- **The objective function** – Dispatch and market outcomes will differ depending on what form the objective function takes. For example, the combinations of units dispatched to maximise VRE output will differ from those dispatched to minimise intervention costs or those which would maximise the difference between the cost and benefits of intervention. This also means that constructing any price-based alleviation supply curve will be difficult, thus making efficient procurement decisions similarly challenging.
- **Timeframe** – Dispatch and market outcomes will also differ due to the period over which the objective function is optimised. For example, the units able to participate in the UCS over a 10 minute ahead optimisation will be different to a day ahead optimisation.
- **Who pays** – Market benefits could be slim if VRE generators bid for constraint alleviation via the UCS, particularly if it results in much lower pool prices. However, if load pays for UCS interventions via a central buyer approach, it will simply result in an inefficient free-rider problem with a smearing of costs unreflective of the true benefit received.
- **Central commitment** – It is unclear if, or how, dispatching plant to alleviate constraints that result in lower market prices as a by-product could be differentiated from dispatching generation solely to lower market prices. Thus, raising the spectre of central commitment.

Unfortunately, these issues have not been discussed in the necessary depth at the ESB TWG Deep Dive sessions to date. For example, despite being a major agenda item of the fourth TWG, scheduling of contracted versus uncontracted resources for market benefits via the UCS and associated issues could only be given cursory consideration given time constraints.

We note that the next opportunity to appropriately consider these issues will only arise with the AEMC's Draft Determination on Delta Energy's Capacity Commitment Mechanism rule change proposal. This is scheduled for publication in late June. This is around the same time as the ESB's final P2025 recommendations to Ministers are due. We do not see how sufficient consideration of these issues can take place for the ESB to realistically endorse any UCS recommendations. We, therefore, recommend that the AEMC take carriage of any further exploration of the UCS as part of a detailed forward work plan post the planned disbandment of the ESB.

System Security Mechanism and Integrated Ahead Markets are not required and are strongly opposed

As noted in the Options Paper, the general objective of a SSM is to maintain power system security by coordinating the dispatch of resources that are uncontracted or do not have a real-time price. However, as with the OR discussion above, it seems this mechanism lacks a convincing rationale given other ESS developments. That is, with:

- real-time prices likely to be seen as part of FFR, PFR and inertia market developments, and
- recent analysis by Endgame Economics showing there to be little need for a short-term mechanism to resolve extreme and unforeseen ramping and unexpected contingency events, even in situations of high renewables penetration.

That would seem to leave only system strength as a resource for a SSM to schedule. However, we note that the new framework intends to provide a proactive and efficient level of system strength at all times. Although there may be limited situations where this does not result, such as in the case of unexpected outages, these are exactly the circumstances that existing NSA and the mooted UCS are designed to address. For example, by notifying the market of any impending gap and AEMO's intention to activate contracts as necessary should a market response not occur in time.

Previous TWGs and responses to earlier ESB papers[3] have noted the far greater complexity and costs of a SSM and fully integrated ahead markets beyond a UCS. Given this, and the lack of convincing rationale for a SSM noted above, we do not see how a SSM, or an integrated ahead market including a SSM, can be reasonably justified or recommended to Ministers. We, therefore, strongly recommend that there is no further investigation of a SSM or ahead markets at this time.

[3] See Creative Energy Consulting's earlier SAMs report for a rigorous analysis of the costs and complexities of various proposed SAMs solutions.

Section 3: Integration of distributed energy resources and flexible demand

Key Points:

- Cost benefit analysis, level playing field and competitive neutrality principles need to be reflected in the regulatory framework for demand-side participation.
- The ESB's focus should be on barriers to customer participation in demand management markets, and not on perceived barriers to service providers accessing these markets.
- Current evidence suggests there are no real barriers to service providers. New entrants (including non-retailers) are providing demand management services via off market arrangements. There is no need to introduce further regulatory mechanisms.
- If the ESB were to introduce new regulatory mechanisms, any new mechanisms should not inadvertently hinder or prevent market solutions.
- The Trader model needs more definition and may result in inefficient outcomes.

Maturity Plan and Customer Risk tool are strong frameworks with some improvements

EnergyAustralia recognises the risks and opportunities of moving to a market with significantly more demand-side participation and the many complex issues that it raises. We support the use of the Maturity Plan as a targeted and systematic way to work through the issues and agree with the issues nominated for the first release.

We also welcome the Customer Risk tool as an appropriate lens to test future demand-side reform, but with one important addition to reflect that the benefits of consumer protection (risk reduction to the customer), taking into account the scale and gravity of the risk, should outweigh the cost.

We also agree with the ESB's guiding principles for future reform in the demand side participation context, but recommend that the ESB should explicitly include a principle that reflects a level playing field and competitive neutrality.

- In relation to a regulatory level playing field, the provision of a service must be regulated in the same way regardless of who is supplying it. This is particularly important as energy retailers (currently heavily regulated) increasingly participate in new flexible demand service markets (that are less regulated). Over time the boundary between the supply of electricity and new demand management services which control load (and affect supply to the customer) may evolve and become blurred. The regulatory framework should be reviewed as this evolution occurs.
- With regard to competitive neutrality, the regulation of Distributor Network Service Provider (DNSP) participation in new services markets will be critical. Functional separation and ring-fencing requirements will need to be strong enough to prevent DNSPs from cross-subsidising new demand management services through their distribution businesses; or conferring a competitive advantage on DNSP affiliated entities.

Separately, we note that there is no formal retailer representative in the Industry Working Groups under the Maturity Plan. We consider there should be to represent retailer views, much like network views are represented by Energy Networks Australia (ENA).

Lastly, the Maturity Plan should consider how current reform like the Distributed Energy Integration Program (DEIP), the Wholesale Demand Response mechanism and Competition in metering, interact with the issues considered in the Maturity Plan and may in time solve for them.

Below we provide views on the two key areas discussed in the ESB's paper.

Barriers to demand side participation are not regulatory

EnergyAustralia recognises the value of greater demand side participation to the whole energy sector, regardless of who enables it for the customer (e.g. retailers, aggregators or other new entrants).

The ESB states that reforms should try to make it easier for customers to enter the market and obtain value from their demand flexibility. However, it is a misstep to equate barriers to *customer* participation with barriers faced by *potential service providers*. Focussing on service providers and not the customer may result in solving the wrong problem and incurring unnecessary system costs.

In our view, the reasons why some customers choose to not participate in demand-side participation are due to the complexity, cost (of DER), and customer's finding it hard to engage due to that complexity. The problem is not a lack of offers in the market nor a lack of access to service providers. Service providers may face challenges with the economics of demand management offerings – but this will be overcome organically as new technologies develop and more trials are undertaken to test the value of offerings to both providers and customers. We recommend that the ESB re-focus its attention on barriers faced by customers.

The other important consideration is cost to the energy system as a whole. Even if the new regulatory mechanisms are voluntary/causer pays, there will still be broader system costs to AEMO and regulators which will be borne by the whole electricity sector.

We also question whether there is evidence that service providers are facing insurmountable barriers in the first place.

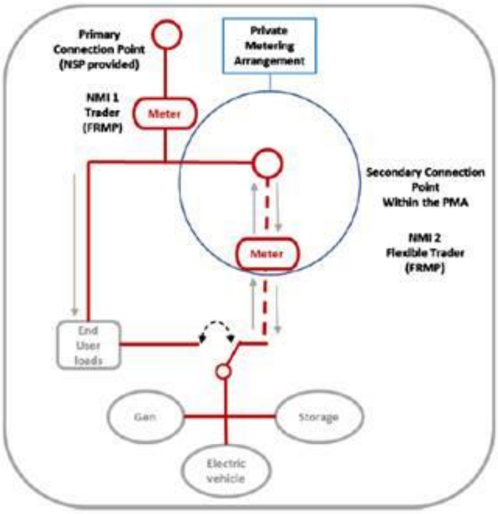
The ESB's proposal of the Trader model and Flexible Trading Arrangements (FTA) (in the transition period to the Trader model) appear to focus on perceived regulatory barriers caused by the current service provider categories being deficient or a lack of access to the customer's premises. The increase in demand response/management offers which are "behind the meter" or "off market" and which involve non-retailer providers (sometimes partnering with retailers) tends to suggest that there are no real barriers in practice.

For example, Tesla has partnered with Retailer Energy Locals in South Australia to provide an energy plan to customers with batteries and aggregate the operation of the batteries to provide a Virtual Power Plant (VPP).[4] Tesla has also partnered with SA Power Networks to test the benefits of VPPs through the use of dynamic, rather than fixed, export limits.[5]

New Flexible Trading Arrangements are not required

The ESB seeks feedback on two FTA models. Model 1 relates to an expansion of the current SGA framework which we understand will progress and which we see potential merit in. The ESB should focus on making the SGA framework more accessible and reducing the cost barrier of establishing a second connection point (which often involves additional costs of upgrading associated infrastructure to compliance standard).

New Model 2 proposes a new sub-metering type arrangement which would allow a customer to make arbitrage decisions around whether their DER generation/stored electricity should supply the house (End User load) or the grid.



Our main point is that Model 2 can be effectively achieved through "off market" arrangements today where there is a two element meter. Specifically, the "off market" product can be set up through the DER operator (operator of Gen/Electric vehicle/storage in the diagram) contracting with the retailer (FRMP at the connection point) to obtain access to the grid, and through shared access to bi-directional meter data at two out of the three points i.e. meters at the connection point and the DER, or the connection point and the house. The third data point can be calculated from the other two data points.

The arbitrage decision of whether to send the DER electricity to the house or the grid can be achieved "virtually" without physically switching the electricity supply between the two. This can be achieved through manipulating the metering data. This is only one example of how off market arrangements can facilitate multiple service providers (the DER operator and the retailer) for the same customer, without the need for Model 2. Both the retailer and DER operator would appear to have the incentive to contract and work together, or otherwise risk losing the customer.

Solutions which make it simple for customers are likely to be embraced by customers. It is unclear whether a customer would want to have to manage the arbitrage decision in the first place. Given only a small proportion of customers are highly engaged in electricity decisions

[4] canstarblue.com.au/solar-power/tesla-energy-plan/
[5] https://arena.gov.au/assets/2021/05/advanced-vpp-grid-integration-final-report.pdf

today, the more likely scenario is that the arbitrage switching decision is a decision that customers would outsource to a single provider – which tends to support a single provider supplying both the house and being the DER operator.

It is also unclear whether customers would want to engage with multiple service providers generally. EnergyAustralia currently offers demand response products to C&I customers, but not products that allow participation in FCAS markets. Several of our large energy customers have indicated they would prefer to bundle demand response and FCAS services with one provider. In the residential market, insights from internal research on bundled services also showed that a common pain point was around the inconvenience and complexity of having multiple suppliers. This view is supported by the increasing bundling of cross sectoral product offerings e.g. energy and NBN by several providers.

In view of off market solutions and questions around customer appetite for multiple service providers, we recommend that the Flexible Trading Arrangements stream be paused until required and deferred to the final releases of the Maturity Plan.

In the meantime, the ESB could explore smaller changes to make off market solutions easier:

- Facilitate the accessibility and sharing of metering data.
- Revisiting requirements for embedded network child connections to ensure they are fit for purpose for DER connections with bi-directional flows. This can include child connections without a NMI (off market solutions do not require a NMI).
- Networks should develop standardised network tariffs that are appropriate for DER imports and exports (continuing current DEIP work). This should be standardised across all networks to promote interoperability and efficiencies.
- General customer education that explains common concepts such as baselining to increase customer comprehension of demand management etc.

New mechanisms should not inadvertently hinder the development of market solutions or prevent them altogether

Our final point is that if the ESB were to introduce a regulatory mechanism to facilitate multiple service providers, any new mechanisms should not inadvertently hinder the development of market solutions or prevent them altogether. It will be important to preserve opportunity and agency for customers who participate in DER (e.g. via retail energy offerings rather than DNSP or AEMO control of devices, or network tariffs that reward behaviours rather than have high unavoidable charges).

Similarly, the ESB could also play a role across jurisdictions to ensure that other unrelated regulatory change does not unintentionally preclude market developments. For instance, DELWP's (Vic) ban on embedded networks may unintentionally ban off market solutions depending on technical definitions.

Trader model needs more definition and may result in inefficient outcomes

Our main additional comment in relation to the Trader model is that it still requires more definition. We also question whether disaggregating energy service provision to multiple providers is economically efficient. For example, the customer may reduce load exposure to spot prices via one trader. However, since the retailer has already purchased contracts to cover this consumption, and charged the customer for this, the customer is not accessing the full benefit of its response. It would be more efficient for the customer's retailer to avoid purchasing risk management products in the first place, delivering lower prices, and then reduce the customers actual consumption, delivering lower bills. A similar argument can be applied to the Flexible Trading Arrangements above to question the efficiencies of multiple service providers at the one premises.

Schedule lite and alternatives should be further explored

We agree *with progressing consultation* around a voluntary form of scheduled lite. The ESB could also look to the self-forecasting requirements for the ARENA VPP program which could be developed as an alternative to schedule lite. In the ARENA VPP trials non-scheduled VPPs self-forecasted load to AEMO and then scheduled accordingly to the forecast. This provided visibility to AEMO and some firmness without requiring participation in central forecast and dispatch processes.

Section 4: Transmission and access

Key points:

- We remain concerned that consumers will face all the risks and costs of large, transformative transmission investments.
- We support the ESB's work on creating the 'Actionable' ISP and in guiding REZ development frameworks. Departures from NEM-wide planning and cost-benefit assessments pose a significant risk to long-term customer interests, and this should be given more weight by the ESB and ministers in implementing post-2025 reforms.
- The separate question of transmission access reform is problematic. The ESB is primarily focused on complementing planning frameworks by promoting quite technical economic incentives, with the expectation that market signals will significantly shape the delivery of unprecedented amounts of new generation and storage investment in the coming decades.
- The transitional pathway envisaged by the ESB involves stepping from REZ-specific access regimes, to a medium-term NEM-wide arrangement, then to a long-term solution involving LMPs and FTRs, within the space of around 10 years. This would be unnecessarily disruptive and materially hamper prudent investment.
- The ESB should consider less ambitious reforms than set out in its options paper, particularly as other market changes should at least partially address the problems identified by the ESB. The ESB's recommendations should be based on, or set out a pathway for, further analysis to fully explore costs and benefits of the preferred range of options.

National frameworks are critical — the ISP, RIT-Ts and contingent projects

In our view, if jurisdictional interventions significantly depart from NEM-wide planning pathways, and are decided on the basis of impacts solely within state borders, this will likely result in customers facing materially higher costs and poorer reliability outcomes than decisions based on integrated NEM-wide assessments.

As the ESB has noted, NSW (and likely other jurisdictions) will be developing access regimes for Renewable Energy Zones (REZ), alongside long-term generation investment targets which will impact on the timing, amount and location of required network hosting capacity. The NSW Government has already declared five REZs, while the 2020 ISP identified Central-West Orana as 'actionable', with the New England and North West REZs identified as a development opportunity from the 2030s. The Victorian Government has also allocated $540 million for 'stage one' network projects, for delivery in the next two to five years, to support six REZs in its jurisdiction, which have similarly not yet been triggered by the ISP or RIT-T framework.

The ESB cannot dictate jurisdictional policy, however can play an important role in reaffirming the benefits of the nationally consistent frameworks that already exist. In our view, this is more critical and of greater impact to customers than the potential benefits of locational investment and congestion management signals.

The ESB questions the additional benefits of RIT-T assessments that occur between ISP and Contingent Project Applications.[6] In doing so, it overstates the ability of the ISP to accurately determine the prudence of certain network solutions amongst a range of potential alternatives. The ISP's role is to identify emerging system needs i.e. the requirement for an investment solution, not which solution is most efficient. We appreciate jurisdictional governments may wish to see transformative transmission projects progress faster — these assessments should take as long as necessary to safeguard consumers from paying excessive costs. The recent delays associated with Project Energy Connect reflect how finely balanced this assessment can be, particularly when there are significant upward revisions to transmission costs. Work to develop more accurate cost estimates is already under way that will help future assessments. Governments wishing for investments to be obviously NPV positive and hence fast-tracked through regulatory approvals are able to contribute funding to projects. We oppose suggestions to weaken this approval process and push the risk of marginally beneficial investment onto unwilling consumers. Changes to processes in the form of Actionable ISP projects should also be given time to work through, namely 'front ending' considerable stakeholder engagement and allowing TNSPs to narrow down the range of considerations and inputs, scenarios etc in their RIT-T assessments.

Governments can also continue playing an important role in completing preparatory work, such as community engagement around route selection and approvals, which should speed up investment timeframes as well as contain cost increases. We disagree with the ESB's suggestion that 'wider' economic benefits be captured in project assessments to guide funding decisions as this is likely to distract from or muddy the water on what electricity customers should pay. Notably, there is a risk that policy-makers will be overly focused on broadening the consideration of benefits, without similarly ensuring wider societal cost impacts are captured, such that taxpayers might not have full transparency on the merits of government 'top ups'. The ESB may wish to consider what information that already forms part of ISP and RIT-T assessments that can usefully inform policy decisions e.g. different jurisdictional impacts.

Where project financeability is a concern for project proponents or governments in delaying prudent investment, the AEMC has already initiated work to examine these issues and this work should be allowed to progress. To this end, we note that Project Energy Connect now appears to have resolved financing issues without the need to amend the economic regulatory framework under the NER.

We support the ESB exploring contestability in the delivery of large transmission projects in order to minimise costs. This should include examination of general expenditure incentives administered by the AER, noting they have been, and continue to be, refined over time. TNSPs already tender for a significant proportion of project costs and adding contestability requirements may increase administrative burden for limited gains. Other cost drivers to be explored include the scale and sequencing of large investment, and the capacities of local workforces and communities to absorb or support them.

We also await the release of the ESB's advice on allocating the costs of interconnectors between jurisdictions. These considerations can be informed by releasing further data on jurisdictional impacts, including modelling of wholesale prices, as part of ISP and RIT-T assessments.

Moving from REZ access to LMPs/FTRs is more than just a 'stepping stone'

The ESB identifies that a NEM-wide regime involving LMPs and FTRs is still an ideal long-term solution, while at the same time developing medium-term solutions that attempt to

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[6] ESB, *Post 2025 Market Design Options – A paper for consultation*, Part A, April 2021, p. 78.

accommodate stakeholder concerns raised about the AEMC's COGATI proposals. The ESB has also devoted considerable effort to providing a framework for 'interim' solutions in the form of REZ-specific access options, which seeks to apply some national consistency to jurisdictional investment frameworks. We appreciate the ESB's challenges in progressing from prior COGATI proposals, and also in accommodating uncertain jurisdictional preferences in REZ access regimes. However, we do not consider it is desirable or feasible to transition from models of REZ-specific access, to a medium-term solution, then to a longer-term solution involving LMPs and FTRs. The ESB characterises its medium-term options as a 'stepping stone' which glosses over how disruptive and wasteful these regime changes would be.

It is not yet clear to us why REZ access regimes will be necessary to provide a locational signal for developers, or provide a potential revenue stream such that the risk and cost of transmission projects can be shared between developers and customers.

In NSW at least, developers will be reaching financial close on the basis of LTESAs, which presumably will only be offered to those connecting inside REZs (thereby providing a very strong, if not blunt, locational signal). The value offered through LTESAs will also reflect the volume and shape of generation output relative to hosting capacity and other connecting generation, which will work to optimise congestion and network hosting capacity in the locations where most foreseeable generation investment will take place. This includes capturing system strength and scale efficiencies through REZ connection and tendering processes. That these interventions will be centrally planned highlights the importance of integrating with NEM-wide assessments such as the ISP, relative to providing economic signals to guide otherwise uncoordinated investment.

We appreciate the ESB must take the prospect of REZ-specific access regimes as a given and appreciate recommendations to ensure national consistency under its Stage One and Stage Two REZ planning consultations. We note the ESB's recommendations on interim REZ frameworks will be submitted to ministers, and having visibility of these would be useful in understanding how its post-2025 options will integrate with any state-based regimes.

The ESB has a more direct role of promoting NEM-wide access models. Rather than leave COGATI open as a lingering risk, the ESB should make clear recommendations on whether or not models involving LMPs and FTRs will be adopted, and if so, when, including a detailed transitional pathway. This will be critical in providing long-term clarity to investors for the decisions they will make in the short to medium term.

Updating cost-benefit analysis may indicate a reduced need for ambitious reform

The options canvassed by the ESB touch on two main issues:

- providing efficient locational signals, which ultimately contain congestion to optimal levels and minimise associated transmission costs
- providing efficient dispatch signals, which will address disorderly bidding and provide signals for storage (and potentially load) to operate in a way that mitigates network congestion.

We consider the ESB has undertaken a fair analysis of a range of options that would address these issues, and also placed weight on concerns raised in consultation on COGATI. On the basis of these considerations, the ESB's preference to introduce a model with LMPs at its heart while also providing an auxiliary locational signal (in the form of a separate connection or ongoing usage charge) seems sound in principle.

However as per our feedback on the COGATI proposals, and noted above with respect to national planning frameworks, we consider that the likely benefits of introducing access reform need to be considered in light of enhancing centralised planning under the Actionable ISP and via REZ development frameworks. The ESB (and the AEMC before it) regard these reforms to be complementary, however there has not yet been a systematic attempt to quantify system inefficiencies in a counterfactual with staged REZ tenders and release of network hosting capacity in a way contemplated by the NSW Government (and likely to be emulated by other jurisdictions).

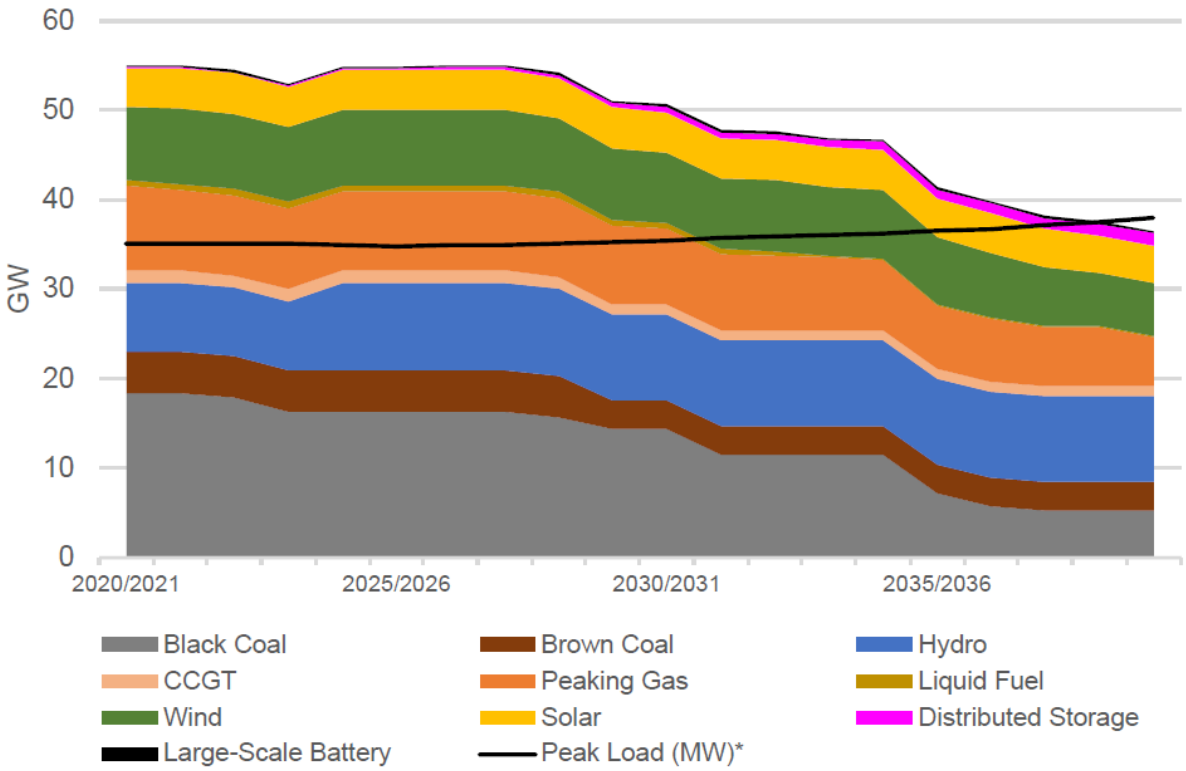
Similarly, the ESB's conclusions regarding disorderly bidding inefficiencies appear to be almost entirely based on earlier modelling conducted by NERA for the AEMC. These benefits were associated with coal plant being dispatched out of merit order, with benefits declining as coal plant retire. To the extent disorderly bidding constitutes a significant part of the ESB's problem statement, further analysis should explore the very large discrepancies between the modelling of benefits by NERA (up to $1 billion), and modelling by ROAM Consulting in 2013, which found benefits in the order of $19 million.[7]

NERA's modelling could also be refreshed to consider the pronounced likelihood of accelerated coal plant exit given more recent spot price trends, with a proportionate decline in benefits to be captured from introducing LMPs. NERA's modelling suggested that system cost inefficiencies would arise almost entirely as a result of black coal being dispatched out of merit order. [8] These plant are likely to be more sensitive to deteriorating capacity factors and spot prices than other existing forms of generation. NERA's modelling also took coal retirement dates as exogenous rather than based on economic closure decisions within its modelling. AEMO's Step Change scenario (now more probable given NSW announcements) shows black coal exiting the system much more rapidly relative to announced closure dates.

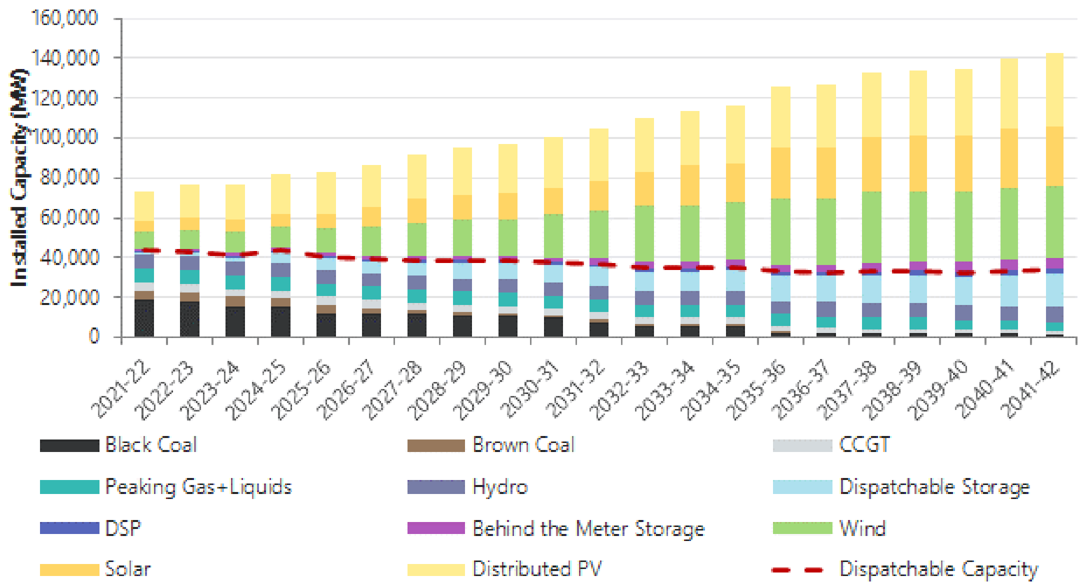
[7] https://www.aemc.gov.au/sites/default/files/content/271255f4-4323-4931-934d-50566be6be5b/ROAM-Consulting-Modelling-Transmission-Frameworks-Review.PDF. See pages 53 and 54, the value of $18.6 million presumes a 5 per cent transmission outage rate.

[8] https://www.aemc.gov.au/sites/default/files/2020-09/NERA%20report%20Cost%20Benefit%20of%20Access%20Reform%202020_09_07.pdf, pp. 52-54.

Figure 2.3: Existing Capacity Mix, 2020-2040



Source: NERA, 2020.



Source: AEMO 2020 ISP – Step Change (DP1)

The ESB's Congestion Management Model (CMM) has the potential to create different and perverse incentives around disorderly bidding. That is, generators currently 'race to the floor' with their pricing bids as congestion rents are allocated on the basis of dispatch volumes. By changing the allocation method to one that is based on generator availability, bidding incentives are shifted from price to volume. That is, generators will have an incentive to maximise their availability bids. Availability is, however, less variable and bound by closer review by AEMO/AER as it affects reliability and reserve calculations. Ultimately this behaviour should be corrected through enforcement of good faith bidding rules, however these factors are worthy of consideration if the ESB further pursues the CMM. The ESB should also consider building on the AEMC's analysis of cost impacts to explore the extent to which a CMM framework, as a stepping-stone from REZs access to a long run model of LMP and FTRs, would be less costly and still result in net benefits to consumers.

Other changes can address disorderly bidding and locational signals

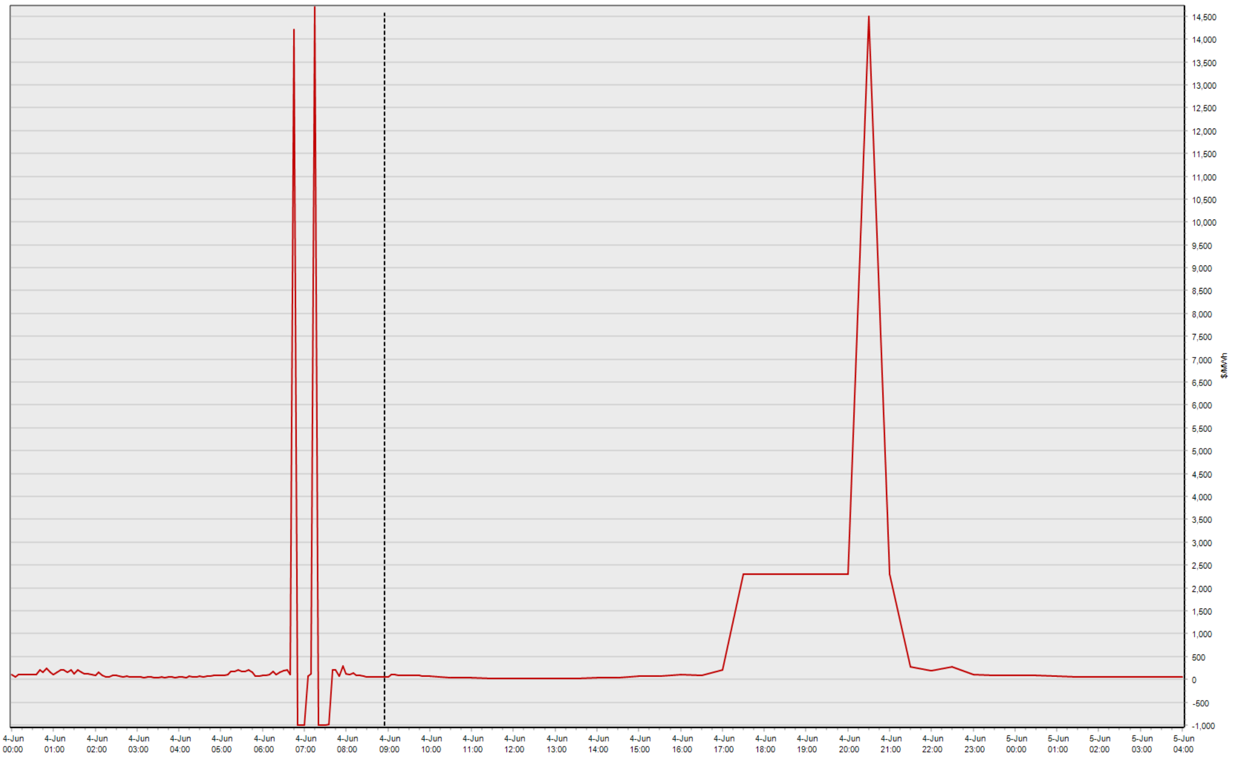
In addition to revisiting earlier cost-benefit assessments in light of more recent policy announcements (i.e. REZ planning and government investment targets) and deteriorating outlooks for coal plant, we recommend the ESB also consider:

- the change to 5-minute settlement (5MS)
- the role of loss factors
- the impact of system strength reforms
- the treatment of interconnectors in constraint equations.

The impact of changing from 30 to 5-minute market settlement will be significant and did not form part of NERA's modelling approach. That is, we expect incentives for disorderly bidding to significantly decline under a 5-minute settlement framework. The ESB identifies that the cost of reform models should be reassessed in light of 5MS interactions[9] and re-examining benefits also seems a reasonable request. We expect incentives for disorderly bidding (where participants look to modify their dispatch within a broader 30-minute trading interval to capture 5-minute outcomes) to significantly decline under a 5MS framework.

To illustrate this, the chart below shows price outcomes in QLD for the 6:30 and 7:00 settlement intervals on 4 June 2021. It shows prices reaching close to the market price cap with participants putting in bids at the price floor to stay in dispatch, and so share in the higher average prices over each of the 30-minute intervals. With settlements moving to 5-minute intervals our expectation is that such bidding opportunities would no longer exist. Notably, with the incentive for negative bids reduced, plant would have bid and been dispatched in merit order, although customers would have paid much higher prices for the affected trading intervals.

[9] ESB, *Post 2025 Market Design Options – A paper for consultation*, Part B, April 2021, p. 99.



Source: EnergyAustralia

The ESB also states that more coordination of transmission and generation "will also reduce the risk of low marginal loss factors and facilitate grid connection."[10]

Regarding grid connection, elsewhere the ESB notes that the AEMC's system strength reforms will support more timely connection of new generation. The ESB suggests these changes are complementary to access reform, noting that system strength issues can be integrated into REZ planning arrangements.[11] However, it is not clear how these reforms are complementary, and also how access reform will improve connection times. If anything, changing from the current 'open' access regime to models that require explicit or implicit valuation of congestion risk, including by centralised agencies in setting G-TUoS, access connection fees or in auctioning of rights, will add to the list of matters to be assessed and settled when project proponents wish to connect. System Strength reforms will incentivise efficient locational investment through new remediation charges and planning mechanisms that explicitly signal the value of 'strong' and uncongested networks. In lieu of access reform, the ESB should consider the sufficiency of these signals as well as others arising from improving existing locational signals as discussed below.

Deterioration of loss factors is an important consideration for connecting participants and warrants further attention. The ESB seems to suggest that access reform would help maintain stability in loss factors, however loss factor deterioration is a key locational signal, and one that is currently dampened for practical purposes i.e. they are 'static'.

[10] ibid.
[11] ibid., p. 82.

We note loss factors have already been considered in prior rule change proposals. The ESB has presented high level analysis based on existing static loss factors and suggests "MLFs are not good substitutes for price signals that reflect congestion."[12] However it may be worth the ESB revisiting this matter and considering a more pragmatic solution where MLFs change on a semi-frequent basis, e.g. monthly, or providing 'shape' around losses that are still static but are different across times of the day. This would apply to generation as well as load, providing improved locational and operational incentive for storage, and obviously capture losses more accurately.

The ESB also notes the proliferation of REZs in proximity to regional interconnectors, which diminishes inter-regional trade and introduces associated issues around counter-price flows and clamping. These issues have prevailed since early wind development in the South East SA REZ and raise a more fundamental point around the differential treatment of interconnectors, in terms of coefficients or minimum co-efficient thresholds in dispatch constraint equations relative to in-region generators.

The current formulation of constraints treats interconnectors in the same way as generators where they are included on the LHS as a dispatchable term anytime their co-efficient exceeds the AEMO defined 0.07 threshold. In practice, this means interconnectors with low coefficients are materially leveraged in dispatch outcomes, such that their targets can be varied from one interval to another across a wide range. This range far exceeds a generator that has a defined maximum capacity with ramp rates overlaid. The operation of constraint equations via dispatch presumes infinite ramping capability of interconnects between dispatch intervals and similarly that regional supply can match these swings in power flows. Such extreme ramping directly across interconnectors, and then indirectly into regional supply stacks, will increasingly put pressure on power system performance and compliance all manner of network measures such as line flows, voltages, phase angles and losses are impacted in a manner similar to a fault.

Correction of how interconnects are treated e.g. applying slower ramp rates and/or a higher materiality thresholds in relation to their constraint coefficients (for example increased to 0.20) appears necessary and prudent to manage power system variability and performance (more so as system strength issues become prevalent) as volatile network congestion occurs. This would also provide increased locational signals for generators intending to locate in proximity to interconnectors as they can disproportionally constrain interconnectors due to the leveraging impact of constraint equation coefficients.

[12] ibid., p. 84.