9 June 2021

Dr Kerry Schott AO
Independent Chair
Energy Security Board

Lodged by email: info@esb.org.au

Dear Dr Schott,

POST 2025 MARKET DESIGN OPTIONS – A PAPER FOR CONSULTATION

The Clean Energy Council (CEC) is the peak body for the clean energy industry in Australia. We represent and work with hundreds of leading businesses operating in renewable energy and energy storage along with more than 7,000 solar and battery installers. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

The CEC welcomes the opportunity to comment on the Energy Security Board's (ESB's) Options Paper in relation to the post 2025 market design work program. We acknowledge the significant work that the ESB and market bodies have undertaken to date to design a fit-for-purpose market framework to guide the system towards one which is primarily based on renewable energy. We also appreciate having been involved in deliberations to date through the ESB's post 2025 market review advisory panel and technical working group.

The CEC supports many of the proposals outlined in the Options Paper, particularly those aimed at delivering essential system services. The ESB's proposed measures in relation to frequency response and system strength will introduce much needed reforms that will help keep the system stable and secure while supporting investment in dispatchable generation, storage and demand response, as well as make it easier for renewable generation to connect to the network.

However, there are two areas of particular concern for the CEC:

- The proposed physical Retailer Reliability Obligation (RRO), which we are concerned could entrench revenue streams for incumbent thermal generators potentially beyond their operational or economic life, while at the same time potentially deter new investment in lower cost dispatchable generation.
- The continuing intention to introduce locational marginal pricing (LMP) and financial transmission rights (FTRs), albeit as a longer-term reform, which would introduce significant costs and uncertainty for limited benefit.

The CEC has assessed the proposals put forward in the Options Paper against two overarching principles that we consider should guide the post 2025 market design process. First, each work stream should promote a lower emissions future through encouraging the entry of new capacity, rather than prolonging the operation of existing ageing capacity. Encouraging new, more responsive, more flexible and lower cost technologies to enter the market will benefit customers by reducing costs and improving reliability and security. The CEC is concerned that a number of proposals put forward in the

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Options Paper, particularly the physical RRO, do not meet this criterion and instead provide additional revenue streams to thermal generators that will keep them in the market for longer than is efficient.

Second, certainty is critical for market participants to have the confidence to invest in new projects and for banks to provide finance. Certainty comes from having market mechanisms that are as simple, stable, transparent and predictable as possible and, where changes to market settings occur, the impacts are carefully assessed before being implemented. We consider the ESB should be mindful in recommending any major changes that may impact investment signals in ways that are not yet fully understood.

The remainder of this submission discusses the CEC's perspectives on each of the work streams.

Resource Adequacy Mechanisms

The case for change has not been made

Given the changes that are required to transition to a low carbon National Electricity Market (NEM), it is reasonable to question whether the current reliability framework will provide the right signals to deliver the necessary amount and mix of investment as thermal generation retires. However, to date this analysis has not been presented. The broader reliability framework comprising the energy only market, the financial RRO, the reliability emergency reserve trader mechanisms and contract markets, as well as the interim reliability standard, have not been proven to be deficient. The financial RRO and interim reliability standard have only been recently introduced and so have had limited time to demonstrate their effectiveness in supporting reliability objectives.

In addition, the proposed amendments to the procurement of essential system services combined with the introduction of five-minute settlement in October this year will place greater value on, and so provide additional incentives to invest in, dispatchable capacity. In doing so, this will have the added benefit of contributing to greater reliability.

Without a comprehensive understanding of where any gaps in the reliability framework are, and the impact of those gaps on market signals and investment decisions, it is difficult to design and assess potential solutions. There are significant risks associated with changing existing market frameworks that are well understood by investors and market participants, and so the costs and benefits of doing so must be comprehensively explored. This is particularly the case where the proposed changes would significantly alter the nature of investment signals.

As such, without a clear problem to be solved, the CEC considers the ESB should not be recommending any significant changes to the reliability framework at this stage. Rather, consideration of the need for further reform should be paused until the market impacts of these other measures are able to be seen.

While it is possible the NEM could benefit from a mechanism that provides improved investment signals, the physical RRO in particular has not been developed in sufficient detail nor adequately analysed to provide the ESB with enough information on which to base a recommendation in mid-2021, particularly when there will be limited time for the ESB to fully consider submissions. There are significant gaps in the development and analysis of the physical RRO, which has been developed in a very short timeframe and, while being characterised as a "modification", would represent a fundamental change to the way in which the NEM operates.

Without a clear reason to move away from the status quo, and without any alternatives that would demonstrably improve market outcomes, the CEC does not support any change to the reliability framework. If additional mechanisms are ultimately required to support reliability, alternative options including an operating reserves market should be considered. However, if the ESB considers it necessary to recommend amending the reliability framework, then the CEC considers the triggerless financial RRO is preferable to the physical RRO as it would leave existing wholesale market signals largely in place.

There is a risk that the physical RRO will harm new investment and be costly to consumers

The ESB has proposed a "modified RRO" to strengthen long term investment signals in the market. It is not clear over what time period the ESB would propose to implement any modified RRO. As noted above, the CEC considers the ESB should not recommend any substantive changes to the reliability framework before current measures have an opportunity to work. This includes the financial RRO, which was introduced less than two years ago, and its effectiveness has not yet been tested.

The six "key measures of success" that the ESB has outlined for the RRO are broadly sound. The CEC would add that the RRO should be revenue neutral to encourage an efficient mix of generation, storage and demand response, and should avoid extending the life of ageing thermal generators that would otherwise naturally retire.

The CEC is concerned that the physical RRO as presented in the Options Paper will not meet many of these success measures and could have the opposite effect of chilling new investment and increasing costs for consumers for no tangible benefit.

There are four main reasons for this.

1. The physical RRO will be costly to consumers

The physical RRO will be highly costly, particularly compared to the status quo. Under the financial RRO, arguably the primary cost is associated with compliance. The financial RRO essentially places a regulatory framework around existing BAU processes, whereby retailers enter into contracts to cover their expected load.

However, the physical RRO introduces new costs associated with buying certificates that have no intrinsic value, other than for retailers to meet their obligations under the scheme. Ultimately these additional costs will be passed on to consumers. Without evidence of an investment problem, consumers would essentially be paying higher costs for the same service.

There could also be a risk that customers end up paying for capacity that is not required. The size of the penalties for non-compliance, combined with individual business' risk appetites, will determine how much capacity they decide to over-procure (or, in the case of certificate sellers, reserve as back-up) in order to meet their obligations. The higher the penalties and the more conservative market participants are, the more capacity may be over-procured.

2. The physical RRO will harm new investment

The physical RRO could create significant uncertainty and so reduce investor confidence. Important details are yet to be developed around how the physical RRO would work in practice and, critically, how it would interact with other market signals. Key elements currently missing from the design of the physical RRO include:

- What are the criteria for "firmness"?
- How much firmness can be provided by interconnectors?
- Will firmed wind and solar be eligible to supply physical RRO certificates?
- Will physical capacity be contracted long term?
- Will there be a centralised system for buying and selling certificates?
- What will be the penalty if a provider of physical capacity is not available at a key time?

Developers will still need long-term offtake contracts, similar to wind and solar developers needing Power Purchase Agreements (PPAs) under the current Renewable Energy Target. If a physical RRO does not lead to multi-year contracts of at least five years, then the physical RRO may not provide sufficient support to secure investors.

Crucial analysis is also yet to be completed. For example, the impact of the physical RRO on wholesale market prices and settings – which currently drive investment decisions – are not well understood. The likely outcome is that wholesale market prices will be supressed, distorting the existing sharp price signals required to incentivise investment in dispatchable technology and demand response. These issues should be explored before the ESB makes any recommendations about implementing an RRO.

Similarly, the value of physical RRO certificates – and therefore the likely cost to consumers of implementing a physical RRO – is not well understood. The price for certificates will likely be volatile, having either a high value or no value. This is because the physical RRO is binary: the market either has enough capacity or it doesn't. This contrasts with traditional capacity markets, which have a demand curve that allows the market to value additional capacity in increments.

As a consequence, a physical RRO will not necessarily address concerns about price volatility held by governments. Further, without more detail on how the physical RRO would work in practice, it is not clear how – or if – investors could reduce uncertainty about the potential revenue streams available from physical RRO certificates. As such, it will be difficult to account for these revenues in developing business cases for new investment, making it difficult to obtain finance without a means to hedge certificate price volatility.

Given there is significant detail to develop, combined with the nature of the changes required, the necessary implementation timeframe for a physical RRO is likely to be at least five to six years. Over this time, the market could see an investment freeze due to uncertainty – the opposite of what is intended – and slow down the transition to renewables. The level of uncertainty will make it difficult not only for investors to obtain finance for new developments but will make it challenging for existing projects to be refinanced.

3. The physical RRO favours vertically integrated "gentailers"

The physical RRO is likely to be anti-competitive as it benefits vertically integrated retailers that have ready access to a physical hedge via their generation portfolio. It is likely to be harder for independent retailers to access certificates, particularly when they may be forced to buy them from their competitors. In 2019, the three largest retailers controlled 46% of generation capacity in the NEM and four second tier retailers controlled a further 18% of generation capacity.[1] Levels of market concentration are higher within regions: with the exception of South Australia, the two largest owners of generation account for over half of total capacity.

Having to obtain physical RRO certificates would be a significant barrier to entry and may lead to retail market exit by smaller, independent retailers, particularly as the price for certificates would need to be high to incentivise investment. A less competitive retail market will increase costs for customers, as well as remove competitive pressure for innovation at a time when digital technology is opening up new opportunities. The physical RRO is also anti-competitive within the generation market, favouring large, vertically integrated incumbents, rather than diverse, renewable generation and storage portfolios.

[1] Australian Energy Retailer, State of the Energy Market 2020, June 2020, p84.

4. The physical RRO will slow the transition to a clean energy market

Finally, the RRO will lead to poorer environmental outcomes. As noted above, critical details about how the RRO would operate in practice are yet to be determined. For reasons discussed above, the most likely outcome is that existing dispatchable generation – coal and gas-fired generation, and some hydro – will receive payments for their existing capacity. This will provide a supplementary revenue stream to thermal generation, allowing them to stay in the market potentially beyond when it would be efficient for them to retire, and when they are more expensive to run compared to renewable energy options. This is inconsistent with moving to a low carbon industry, as well as resulting in a more expensive outcome for consumers.

The CEC does not support the introduction of a capacity market, but we note that full capacity markets do have some features that are likely to lead to improved outcomes compared to the proposed physical RRO, including greater technology neutrality, more transparency, and prices that are more competitive.

While the financial RRO would act as a reliability backstop to ensure electricity security as high emissions technologies exit the market, the CEC is not convinced that existing market signals are insufficient to deliver the necessary investment to achieve this objective. In addition, the physical RRO encroaches beyond its role as a backstop – it would fundamentally change the nature of the NEM through the introduction of a quasi-capacity market.

Exit arrangement options

The CEC appreciates that governments, policy makers and consumers are concerned about the potential cost, reliability and security impacts if replacement capacity and system services are not available in a timely manner as thermal generation exits the market. The CEC supports a number of the measures that have been implemented to support this transition, including:

- Notice for closure requirements
- The financial RRO
- Improved NEM planning, particularly through the Integrated System Plan (ISP)
- The proposals by the ESB to introduce new mechanisms for procuring essential system services (ESS)
- The development of Renewable Energy Zones (REZs) to support renewables investment.

If there are residual risks, the CEC supports consideration of additional measures that may be required beyond these reforms that would help smooth the transition, provided they do not unnecessarily extend the life of thermal generators beyond what is efficient or distort the market in any other way.

The CEC has some concerns with the proposed integrated process intended to allow governments to manage the early exit of thermal generation. The proposed process provides Governments with an easily-facilitated mechanism to contract with a thermal generator to prevent it from retiring early. The CEC's concern is that the easier this process is, the more likely it is that Governments may opt to exercise this mechanism where they are concerned about the impact on prices.

This has two problems:

1. By supressing prices, the market will not receive the signals required to invest in new generation, storage and demand response.
2. Simply having the mechanism available increases risks associated with potential new projects, if investors consider there is a real possibility that Governments will exercise that mechanism and contract with thermal generators to stay on – essentially crowding out new, cheaper and greener technology.

The CEC considers that if this approach is recommended:

- There should be a clear process for exploring options for providing security and reliability services via competitive processes before any contract is offered to an existing thermal generator. This should include opportunities for repurposing the site.
- Governments agree to transparent and strict controls around when the option to enter into an Orderly Exit Management Contract may be exercised.

Integrating jurisdictional schemes

The CEC broadly agrees with the financial principles that the ESB has proposed Governments adopt when designing long-duration contracts to incentivise investment; that is, leaving parties exposed to real time pricing and entering into bilateral contracts with market participants rather than relying on underwriting contracts with governments.

In terms of information provision from the market to governments, the CEC considers that there is already sufficient market information available via existing processes. This is provided through the Electricity Statement of Opportunities, the ISP, and the Medium-Term Projected Assessment of System Adequacy. However, to the extent that additional information is reasonably required by governments, this is best facilitated through these existing processes to avoid duplicative requirements, multiple processes and potentially multiple compliance regimes.

Finally, governments should be as transparent as possible about their investment/funding plans to provide certainty and important information that may influence investment decisions. As such, the CEC supports the ESB's recommendation that jurisdictions provide information on their investment schemes.

Essential System Services

Cost recovery of ESS

A critical aspect common to all essential system services is how the cost of providing these services will be recovered. A number of factors need to be balanced in deciding whether a causer-pays or beneficiary-pays approach is appropriate. In considering the cost recovery arrangements, the CEC recommends the ESB have regard to the following:

- Who is best placed to manage the risks and to minimise costs associated with procuring the services, which will ultimately be passed on to consumers.
- The impact on the transition to a low carbon industry. If renewable generators are required to pay for ESS, this cost will be reflected in the wholesale price. Thermal generators that are not required to contribute will receive the benefits of the higher wholesale price without the additional costs of the ESS. This will provide them with additional revenue, potentially keeping them in the market for longer than is efficient and slowing the transition to a low carbon market.
- Whether it is possible to assign costs to individual market participants, as is required under a causer-pays approach. Where it is difficult to attribute the cause of the need for the service to any particular market participant, it may be appropriate for consumers to bear the cost.

Frequency Control

The CEC supports the ESB's recommendation to prioritise the refinement of frequency control arrangements for immediate reform.

The CEC generally supports the Australian Energy Market Commission's (AEMC) draft decision to implement two new fast frequency response markets for very fast raise and lower services. However, as noted in our submission to the AEMC, the CEC considers that the two markets should be implemented more quickly than is currently proposed. Given the length of time that other significantly more substantive reforms have taken, such as five-minute settlement with a three year and seven month transition period, we consider that the new fast frequency response (FFR) markets could be implemented in well under three years.

Further, it is important that the approach to FFR is technology neutral. FFR can be provide in multiple ways, including by batteries and demand-side response as well as via interconnectors. The new rules should allow each of these technologies to participate on a level playing field.

In respect of primary frequency response, we agree that alternative, market-based mechanisms for provision of PFR should be explored, rather than the mandated approach that is currently in place.

We look forward to engaging further with the AEMC as these rule changes progress.

Structured procurement arrangements

The CEC strongly supports the proposed amendments to the structured procurement of system strength by transmission network service providers, and the recommendation that these be progressed immediately. While there are a number of details to be resolved, the CEC supports the proposed measures set out in the AEMC's recent draft determination on this issue, including the proposed system strength planning standard, generator access standards and system strength mitigation requirements. We consider that these measures will help resolve deficiencies identified in the current framework and will better support system security.

Operating reserves

Consistent with our earlier submissions, the CEC continues to support a more detailed exploration of an operating reserve mechanism as a resource adequacy mechanism. An operating reserve mechanism could support reliability objectives by sharpening price signals to ensure resource adequacy in operational timeframes.

The Options Paper notes that operating reserves will continue to be considered in the coming months, but appears to focus this consideration on whether operating reserves would provide a "positive externality"[2] for resource adequacy, presumably if implemented to support security needs, rather than a mechanism to promote reliability in and of itself. Instead, the ESB continues to focus on a modified RRO as the primary mechanism for supporting reliability objectives.

The results of modelling commissioned by the AEMC suggest an operating reserve service is unlikely to be needed to support system security.[3] As such, it seems unlikely that an operating reserve will be implemented for this purpose. Therefore, any further consideration of operating reserves will need to be first and foremost as a resource adequacy mechanism.

Given the risks and costs of implementing a physical RRO, as articulated in the previous section, the CEC continues to advocate for exploring operating reserves as an alternative reliability mechanism to a modified RRO.

Unit Commitment for Security

The CEC is broadly supportive of the UCS on the basis that it streamlines and better operationalises the Australian Energy Market Operator's (AEMO) directions and interventions processes by providing a mechanism to schedule resources that have been contracted through structured procurement. In doing so, we would expect the cost of providing additional reliability to reduce compared to today. Further benefits include:

- Obviating the need for manual collection of information, assessment and identification of resource gaps
- Increasing transparency by identifying and communicating potential gaps and providing sufficient time for the market to respond
- Providing consistent application and pricing of direction and intervention events.

There are a number of important issues that will still need to be resolved as the details of the UCS are further developed. These include:

- Being clear on what the UCS is trying to achieve i.e., what is the optimisation problem it is solving for and how will this be achieved in practice?
- Designing the UCS such that contracts are procured and the service is dispatched without disrupting competitive pricing behaviours and outcomes in both the energy and ancillary services markets. This includes understanding how the presence and use of the UCS may impact bidding behaviour.
- Ensuring the UCS is transparent so it is clear how contracts are identified for dispatch.

It is important that these issues are given due consideration, including being socialised with industry, to fully understand the likely impacts of the UCS in related markets. The next opportunity for industry to consider these issues will be following the publication of the AEMC's draft determination on Delta

[2] ESB, Post 2025 Market Design Options – A paper for consultation, Part A, p39.
[3] AEMC, Reserves Rule Changes (ERC0295 and ERC0307), Rule change – deep-dive workshop 1, 22 April 2021, minutes, p4.

Energy’s Capacity Commitment Mechanism rule change proposal, scheduled for late June. This is around the same time as the ESB is due to provide its final recommendations to Ministers. As such, it is not clear that the ESB will have sufficient information to endorse any specific UCS recommendations at this time.

The CEC would support the AEMC taking carriage of the further exploration of the UCS as part of a detailed forward work plan, and we look forward to continuing to engaging closely with market bodies as the mechanism is further developed.

System Security Mechanism

The CEC considers that the UCS is of greater priority than any shorter-term system security mechanism (SSM) and, as such, considers the focus of the ESB’s recommendations and further work should be on developing the UCS. As noted above, there are important details that still need to be addressed in order to further develop and fully assess the costs and benefits of the UCS.

The need for a further mechanism to procure system security services in the short term has not been explored. The CEC’s initial position is that the suite of measures currently being proposed to improve system security are likely to be sufficient, and that their effectiveness should be tested in practice to ascertain whether any gaps remain before the SSM is considered further.

Some critical questions about the SSM still need to be explored, including:

- what exactly the SSM would be used for and the circumstances under which it might be used
- how it would interact with the UCS, including incentives on market participants to strike longer term structured procurement contracts versus providing short term reliability via the SSM
- who the costs would be recovered from and how the risks of unpredictable costs of procuring SSM in a short timeframe could be managed
- how the mechanism would integrate with other process.

These issues have not been given sufficient consideration to date to provide the ESB with the necessary information on which to base a recommendation to adopt the SSM.

Inertia

Given the relationship between various ESS, there is merit in examining the need for a separate procurement mechanism for inertia. For example, while inertia and FFR are related and the level of one in the system will influence the requirement for the other, they are not complete substitutes. Arguably, as a separate and distinct service, the value of inertia also needs to be made explicit so as to procure an efficient overall mix of system services.

There is a risk in valuing some services and not others that market participants will experience skewed incentives, resulting in overinvestment in some technologies and underinvestment in others. While a market for FFR will provide important incentives for investment technologies such as battery storage and demand response, a market signal for inertia will encourage innovation and investment in synthetic inertia technologies that will help underpin the grid transition.

Inertia could be procured via a spot market or structured procurement, and the CEC encourages both these options to be explored. Obtaining an efficient mix of ESS may imply having multiple, co-optimised markets for each system service. However, this introduces additional complexity that may not be warranted and, in some instances, such as for system strength, a structured procurement approach is appropriate. There is also a possibility that individual markets for ESS would not be sufficiently deep to support competitive market outcomes. All these issues will need to be explored.

Given there is a degree of substitutability between inertia and other ESS, as an initial step we recommend that analysis be undertaken to understand if addressing the system strength gap and introducing new markets for FFR resolves the inertia gap, or whether inertia needs to be separately priced and procured to achieve efficient outcomes. There may be merit in bringing forward this analysis.

Ahead markets

The CEC agrees that ahead markets are not a priority and do not warrant further consideration at this stage. Rather, getting the frequency control and system strength frameworks in place as a matter of urgency, followed by the UCS, should be the focus of the near to medium term. The CEC also agrees with the ESB's view that the case for an integrated ahead market and energy trading will depend on future market developments, and we would add that the need for any additional mechanisms should be assessed after the existing reforms have been implemented and have had an opportunity to work.

The integration of distributed energy resources and demand side participation

We welcome the ESB's support expressed in Options Papers for enhanced participation of distributed energy resources (DER) and flexible demand in markets. We support the increased role of demand management and demand response in providing system and network services, provided that customers will be rewarded for the provision of these services.

We support the increased focus on customers, and the importance of consent and consumer choice. We also support the increased participation by aggregators.

We are concerned by the absence of a vision, goal of desired end state for DER. Without a goal it is difficult to know which policies should be prioritised and whether they will assist in achieving aims for the sector.

We are disappointed that the ESB has not proposed clarification of the roles of market participants in relation to DER. Clarification of roles and responsibilities is a foundational piece of work and without that clarification there will continue to be gaps and overlaps in policy and regulation for the DER sector.

We are also disappointed that the Options Paper does not attempt to address the critical issue of which DER services are mandated, and which should be paid for.

The CEC supports the broad aims of the proposed Maturity Plan. We are pleased that the ESB does not propose to have a large number of reforms planned for immediate delivery but has instead chosen to flexibly prioritise issues of most urgency and delay others which require more market certainty. CEC wishes to support the ESB through the Maturity Plan process on matters relevant to distributed energy. For the Maturity Plan model to achieve the broad support across the sector that is required to enable timely progress, we suggest the following:

- It is critical that a robust governance, funding and decision-making framework be established for the Maturity Plan process. We suggest that the AEMC take the lead in establishing an appropriate system to manage this process. We strongly urge the ESB and the AEMC to consider using the approach outlined in the ESB's July 2020 Consultation Paper on Governance of DER Technical Standards.
- It is CEC's understanding that a temporary steering committee has already been formed. We would like to see more robust and longer-term arrangements in place where the peak customer and industry bodies are respected as key nominating entities for steering committee members.
- The Maturity Plan steering committee should be independently chaired like the Distributed Energy Integration Program (DEIP) Interoperability Steering Committee
- There should be a transparent process for selection of Maturity Plan topics and whether the concept of 'co-design' is equivalent to "collaborate" as defined by the International Association for Public Participation framework.

The CEC notes that the ESB has a rule change (Governance of distributed energy resources technical standards) that is currently pending, and this could be an appropriate vehicle through which to progress the Maturity Plan.

We are concerned that there remains a general lack of agreement on the issues we are trying to solve and the priorities for DER policy. The plan for the Maturity Plan dives into the minimum demand issue as though it is the critical issue.

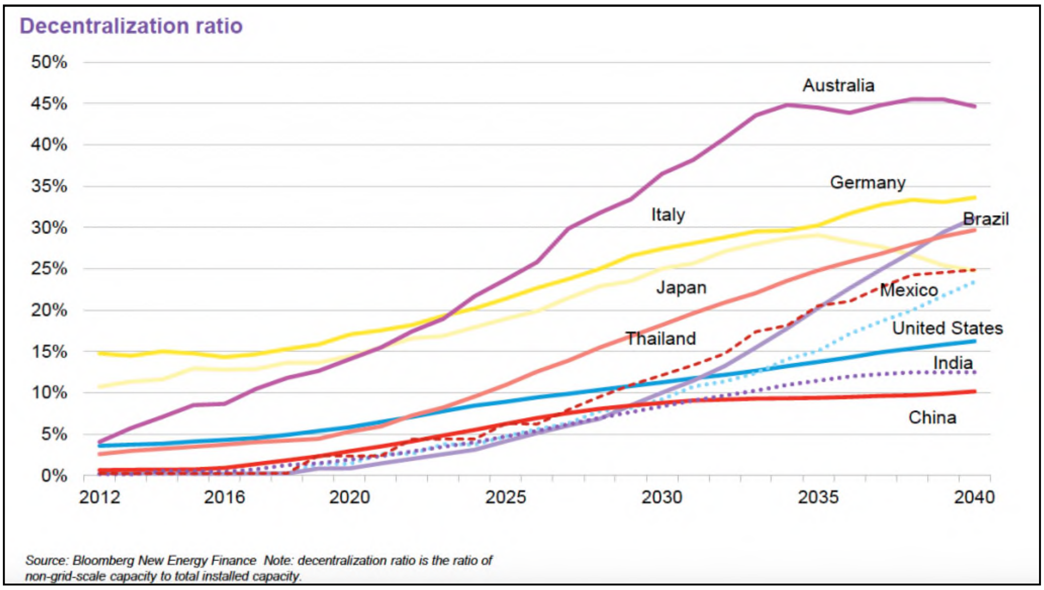
We are disappointed that the issue of climate change and emissions reduction appears to have been omitted.

Some other critical omissions include governance of DER integration, including technical standards and regulation of distribution network service providers (DNSPs), and frameworks for community energy and local settlement.

The principles for the consumer protection framework should recognise that consumers also have a right to install solar PV, batteries, electric vehicle (EV) chargers and related energy management systems.

Responses to questions raised in the Options Papers

The scale of Australia's electricity system decentralisation is unprecedented and internationally ground-breaking. Australia's electricity systems are becoming more decentralised than almost any other power system in the world. According to the AEMO[4] and other plausible scenarios, the coming decades are likely to witness between 30% and 50% of annual volume being served from generation connected to distribution systems.



A significant proportion of this fleet of many millions of distributed generation systems will be customer-owned and sited. Given the significant proportion of privately-owned resources that will serve between 30% and 50% of future generation requirements, a holistic and progressive approach to tariff evolution, market integration and potentially the creation of additional markets will be required to maximise both the full 'value stack' available for DER-owners and the financial incentives for providing the services of greatest value to the power system.

The degree to which this rapidly growing fleet of distributed energy resources is effectively integrated into the NEM will have a significant impact on outcomes for all customers for the coming decades. These impacts will affect both those with DER and those without regarding quality and security of supply, economic outcomes and environmental impacts.

Effectively achieving deep system integration of DER is a non-trivial task. It involves many different disciplines, a widely diffused body of relevant expertise and diverse stakeholder perspectives. It is

[4] AEMO Forecasting and Planning Inputs, Assumptions and Scenarios Report 2020

essential that a robust, properly funded collaborative model be established to coordinate the portfolio of activities to achieve deep 'whole system' integration of DER.

The difference in the depth, maturity and distribution of technical, economic, customer and regulatory knowledge between the traditional centralised power system and the emerging more distributed power system is stark. The traditional centralised power system benefits from a mature body of knowledge and expertise built up over a century and that is highly concentrated in a relatively small number entities (including generators, networks, governments, market and regulatory bodies, etc.). By contrast, the expertise required for the deep 'whole system' integration of the millions of DERs that will need to reliably serve 30 – 50% of the NEM's future generation requirements is far less established. Australia is on the global frontier and as such this body of knowledge is still immature and continues to evolve. Critically, it is widely distributed across a much larger number of entities including various customer types who will be capable of providing both generation and critical flexibility services.

The remainder of our DER and demand side participation section focusses on addressing the questions raised in the Options Paper.

Options Paper A

27. **What are stakeholder views on the issues raised on supporting market participation for active DER? Are there other paths that could be considered for different types of consumers?**

We welcome the support for enhanced DER participation in markets. DER policy is lacking a framework or agreement on which services should be provided through market mechanisms and which should be provided using regulations and standards.

As a general principle, provision of system services and network services should always be paid for and should not be mandated as a condition of grid connection. This should include support for Frequency Control Ancillary Services (FCAS) markets and voltage management on distribution networks. The only exception to reliance on market mechanisms should be genuine, well-defined emergency situations.

28. **Is the unbundling of services delivered by active DER resources from energy supplied by DER viewed as important to allow innovation and new business models? What might be the pros and cons of this approach?**

The ESB Options Paper has not articulated the case for prioritising unbundling of services delivered by active DER from energy supplied by DER over other potential reforms. We do not understand why this should be considered a priority, compared with other potential areas for policy reform.

If the Maturity Plan proposal proceeds, the unbundling proposal is one reform option that could be considered alongside the many other reform proposals that might be prioritised.

29. **What might be the implications of a growing fleet of active batteries and electric vehicles? Are there other pathways that need to be considered to reflect these needs?**

The presence of more energy storage on distribution networks will enable better management and cost reductions for all consumers. Most of the energy storage likely to be installed on distribution networks will be privately owned, either as batteries or grid-connected electric vehicles (EVs). It would be a massive, missed opportunity if we do not enable these privately owned energy storage assets to participate in markets. It will be important to encourage EV charging during daylight hours. This would be assisted by tariff reform and availability of EV charging infrastructure wherever EVs park during daylight hours.

30. Are there constraints on switching providers with DER today? Are constraints on switching likely to occur through standards being introduced now or expected, such as IEEE 2030.5?

DER providers would be better placed than CEC to provide information regarding issues arising with switching DER providers. We would expect standards for interoperability to simplify the process for customers who wish to switch providers.

31. What are stakeholder views on approaches outlined? What might be the advantages and disadvantages associated with each?

The sequence that would seem to make most sense is:

- Review international standards to determine what is most appropriate for Australia, noting that there is already significant momentum behind the adoption of IEEE 2030.5
- Develop an Australian implementation guide for the selected standard, noting that the Australian National University (ANU) is currently working on an Australian implementation guide for IEEE 2030.5
- DNSPs to develop application programming interfaces (APIs)
- Ideally, standardise the market interfaces across DNSPs so that retailers and aggregators need to interface with one interface nationally, rather than one API per DNSP[5]
- Ensure that retailers and aggregators are able respond appropriately to the DNSPs' API(s)
- Leave it to retailers and aggregators to develop the interface with customers' sites and devices behind the meter

32. Are there other potential approaches that could be considered?

It is unclear at this stage whether it makes any sense to adopt IEEE 2030.5 as an Australian standard. It is preferable to utilise a suitable international standard, where a suitable one exists.

There is no need to create or specify a particular communication type or platform such as IEEE 2030.5. Instead, what needs to be specified by AEMO are the parameters - response time, accuracy class, cyber security mechanisms etc. It should be an outcomes-based approach focused on 'the what', rather than getting into the weeds of 'the how'.

33. Under what situations could the distribution network operator perform the role of the retailer / aggregator?

We are very concerned by the inference that the ESB is amenable to the idea of allowing DNSPs to act as retailers / aggregators. This concern is exacerbated by the fact that the ESB Options Papers have not proposed clarification of roles and responsibilities of market participants in relation to DER.

The DNSP should not perform the role of retailer / aggregator. Not under any circumstances.

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[5] Noting that DNSPs may be unlikely to share intellectual property and that the key issue is not ownership but standardisation using a single common market interface

The model for roles and responsibilities should be based on outcomes. AEMO should focus on what it needs from DNSPs and aggregators and should stop trying to tell the industry how to do its job.

A useful contribution that the ESB could make would be to recommend whether all future DER installations should be required to sign up to a virtual power plant (VPP) aggregator or 'Responsible Agent', as is currently the case in SA. The ESB could also recommend the roles of the aggregator or retailer or Relevant Agent (which we will henceforth refer to as the Responsible Party) in relation to managing "minimum demand". The roles of the Responsible Party could include:

- Communicating with the fleet of customers' DER,
- Ensuring that their customers' sites respond in aggregate to the commands issued by the DNSP or the AEMO commands relayed by the DNSP, which would include "backstop" responses,
- Controlling DER and other assets behind the meter in accordance with the wishes and consent of the customer,
- Signalling and passing through financial incentives for import and export and provision of grid and system services, as they do already under VPP arrangements.

It should also be noted that the role of Responsible Parties need not be limited to customers with solar and battery systems. Customers that do not have solar PV could sign up to one of these entities to have them take control of behind the meter assets or maybe even just AC-coupled storage.

CEC proposes a hierarchy of control that starts with the customer, as follows:

- First and foremost, the customer should have control of their assets
- Customers should have a choice as to whether they give some control of assets behind the meter to their Responsible Party. If a customer gives that consent, the Responsible Party would be responsible for controlling assets behind the meter to ensure the site responds appropriately.
- DNSPs should control what enters their network from sites. They should not control assets behind the meter[6].
- AEMO should only intervene in situations critical to system security.
- When AEMO intervenes, they should operate like they do now in South Australia, with instructions issued to the DNSP, which are then passed on to the Responsible Party.
- AEMO should not have control of assets behind the meter. AEMO should not attempt to tell aggregators how to do their job. The role of AEMO should be limited to ensuring that DNSPs respond to AEMO instructions as required.
- The role of the DNSP should be to ensure that Responsible Parties respond as required.
- The role of the Responsible Party should be to ensure that their customers' sites respond as required and this could involve control of assets behind the meter where the customer has given consent for that to happen.

The Responsible Parties would be required to demonstrate their capability to provide the necessary response to instructions from AEMO requiring changes to generation and load (the so-called

[6] Noting that some DNSPs have legacy tariffs and other arrangements based on ripple control of some devices behind the meter. These legacy issues should not change the policy principles.

“backstop” requirement). Exactly how the Responsible Parties communicate with DER assets would vary but the responsibility for the infrastructure would lie between themselves and the product vendors. The Responsible Parties would take market signals to trigger responses and control requests to DER assets. They would also take requests and / or signals from DNSPs and AEMO.

From a backstop or system security perspective there should be a hierarchy of control whereby on a day-to-day basis the Responsible Party would dictate the best way to control DER assets based on ensuring the best return for the consumer. If, however, a DNSP requires a particular event to be managed they can trigger an overarching control or outcome request, and above this AEMO could do the same. Exactly how this is achieved will be down to the Responsible Party. For example, if AEMO want all export to cease the Responsible Party could trigger greater self-consumption by turning on domestic loads, or simply triggering zero export. If AEMO want to have voltage reduced, then the Responsible Party could trigger loads or storage to be activated higher than the PV generation level thus drawing from the grid. It would make sense for AEMO or a DNSP to communicate to Responsible Parties using a consistent Application Programming Interface (API). The emphasis by AEMO should be to ensure that Responsible Parties respond in accordance with instructions rather than trying to tell technology providers how to design new products and services. This model also allows for the Responsible Parties to utilize DER Vendors’ existing communication protocols just as VPPs already do, meaning than very minimum development needs to be undertaken. There will need to be reporting, failsafe and obligations set, but nothing any more complicated than was already implemented in SA.

34. **What are the issues surrounding connection agreements that can facilitate a retailer / aggregator for market participation and the delegation for the enforcement of limits to both DNSPs and AEMO?**

Governance of grid connection agreements is far from good regulatory practice. The governance should be reviewed before giving new powers to DNSPs and AEMO through the connection agreements. We strongly support the ESB rule change proposal on governance of DER Technical Standards. We look forward to the commencement of that review and the opportunity to contribute to it.

We would be very concerned if the ESB is open to allowing DNSPs and AEMO the ability to control devices behind the meter. AEMO should specify what response it requires from fleets of DER, managed by a Responsible Party. AEMO should not tell Responsible Parties how to manage DER fleets.

35. **Noting the differences in market arrangements between the WEM and the NEM, are there aspects of the WA DER Roadmap that could usefully inform how certain roles and responsibilities might evolve in the NEM?**

There is much that can be learned from the example set by Western Australia (WA) and from its DER Roadmap. The ESB should consider publishing its own DER Roadmap.

WA has pioneered the use of stand-alone power systems by distribution networks. It is very disappointing that changes to the National Energy Laws (NEL) to allow use of stand-alone power systems (SAPS) by DNSPs in the NEM have still not been made, after about five years of protracted deliberations. We strongly support the proposed reforms to enable use of SAPS and we look forward to these reforms being finalised soon.

WA has also pioneered the use of neighbourhood-scale batteries (also known as ‘community batteries’) on the distribution network.

The DER Roadmap also outlines a longer-term vision and reform plan that includes incentives to unlock latent capabilities in the existing inverter fleet, improvements to consumer protections, wider use of battery storage and other non-network solutions on distribution grids, trials of Virtual Power Plants, enabling DER participation in wholesale markets, establish a distribution services market and plans to establish and legislate for distribution system operator (DSO) and distribution market operator (DMO) roles. These are all initiatives that should be considered for the NEM.

36. What are stakeholder views on the approaches outlined? What are the potential advantages and disadvantages of each?

The CEC strongly supports a market-based approach to procurement of services from DER. Structured procurement with a digital platform has many advantages. Dynamic price signals in a real time distribution market are also conceptually appealing but could be difficult to implement. It might be most practical to commence with structured procurement with a digital platform provided it is implemented in a way that does not preclude a future move to dynamic price signals in a real time distribution market.

37. Are there alternative approaches that could also work to complement existing tariff reform processes that should also be considered? How might these work?

Tariff reform will continue to be mediocre and inadequate until the failure of metering policy is acknowledged and addressed. At the current rate of installation, the rollout of smart meters will not be completed until the 2040s or later. This is unacceptable. It leads to tariff reform being imposed only on customers that have been forced to purchase a smart meter, either because it is a new connection or because it is a condition of installation of solar PV or a battery. It is unfair and inefficient to impose tariff reform on a small cohort of customers while the majority continue to enjoy flat tariffs and accumulation meters.

38. Do stakeholders have views on additional steps or information that should be considered in the proposed consumer risk assessment tool?

The current consumer protection framework does not recognise the rights of consumers to install solar PV. We urge that this right be recognised in the consumer protection framework under consideration.

A fundamental principle should be that a customer's DER exists for the benefit of the customer, not the network. We should think about how to reform networks to maximise use of DER, not how to reform DER to help networks.

39. Do stakeholders have views on the options outlined to address issues associated with falling minimum demand and increasing access to markets?

"Minimum demand" is a construct that reflects the 20th century electricity market. In the 21st century, the emphasis should be on matching load with generation so that society can take best advantage of the abundant supplies of zero marginal cost, zero emissions electricity generated during daylight hours.

The challenge should not be described as "minimum demand". The real challenge is matching generation and load. There is a minimum visibility and control issue, both for AEMO and the DNSPs. Demand on the network is just consumption from conventional sources. What is not being recognized is DER self-consumption. Minimum demand can already be addressed by controlling installed assets behind the meter. Switching on electric hot water (for example) could have the same effect as switching off solar generation and would be far more beneficial for the customer.

Principles that should be considered when developing the response include:

- The challenge is not “minimum demand” – it is about matching generation and load
- Consuming the abundant supply of zero marginal cost, zero emissions electricity is preferable to remotely turning solar generation down or off
- An incentive-based or market-based approach is preferred to command and control
- Opt in or opt out is preferred to mandatory
- Short term solutions should not get in the way of superior long-term solutions
- Identify the problems you are addressing first – it is deeper than ‘minimum demand’

Some ways to increase system load when solar energy is abundant include:

- Remove the hard capacity limits places by DNSPs on residential storage so that customers can add sufficient storage to reduce solar exports as well as addressing their peak demand profiles.
- Maintain state government incentives for batteries and consider use of $/kWh rebates instead of flat rebates to encourage installation of larger batteries.
- Address barriers to community storage on distribution networks, foremost of which are:
    - Distribution Use of System (DUOS) pricing, and
    - Market access for aggregated community storage.
- Finalise the AEMO Market Ancillary Services Specification (MASS) review in a way that keeps VPP systems in the market, providing more incentives for storage.
- Remove barriers to grid integration of electric vehicles (EVs) and provide incentives for EV uptake.
- Reform tariffs, which could potentially include time-of-use tariffs and payment to increase load during daylight hours

40. What are other options to consider that might deliver better outcomes for consumers?

Finding better ways to use our abundant zero marginal cost, zero emissions energy is preferable to remotely turning generation down or off. In a future system dominated by DER there will be a need for the system operator to be able to change system load. This could be achieved by curtailing generation, increasing load or both. It could be achieved using market-based approaches or ‘command and control’. Use of dynamic operating envelopes by DNSPs should also be expedited.

Recently, market bodies and policy makers have placed too much emphasis on managing risk, rather than unlocking value. Too much time has been spent on AEMO chasing risks and taking the industry down unproductive paths. Industry is distracted from unlocking capability and opportunities because we are reacting to requirements set by AEMO, which might not be helpful.

41. **Do stakeholders have views on the proposed principles? Are there other principles that should be considered to deliver benefits for consumers?**

Principle 1: Consumers should be able to share data with service providers

Support. A consumer's electricity retailer should not be the gatekeeper on the customer's data.

Principle 2: Consumers' DER assets should have a level of portability between providers

Support in principle, subject to consideration of wider costs and benefits.

Principle 3: Control of and access to consumer devices should be limited to clear use cases

Do not support. Only retailers, aggregators, traders or the customer's agent should control devices on behalf of their customer. As a principle, control of devices by networks or AEMO should be avoided.

Principle 4: Consumers need to receive clear information about the compatibility of their DER assets

Support

Options Paper B

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

The co-design approach trialled recently has been noble in its intention but lacking in its execution. It has demonstrated that it would be very challenging to involve consumer advocates in co-design to address highly technical issues. We fully support the involvement of consumer representatives in consideration of energy policy, but the approach used by the Maturity Plan process to date has been ill-conceived.

We strongly urge the ESB to consider using the approach outlined in the ESB's July 2020 Consultation Paper on Governance of DER Technical Standards as an alternative. We are of the view that it is a superior framework for DER governance. We would suggest several important enhancements to the model proposed in the ESB's July 2020 Consultation Paper on Governance of DER Technical Standards:

- The scope should be broadened. It should be a DER Governance Committee, rather than a DER Governance of Technical Standards Committee. It should be created under the National Electricity Rules (NER), convened under the AEMC.
- It should be comprised of members who represent a range of participants in the NEM, including consumer groups, industry associations, technology providers and manufacturers, network businesses, market aggregators, Standards Australia and the energy market institutions.
- The DER Governance Committee (which could be called the 'Maturity Plan' Committee, if preferred) should use a hybrid model that combines advisory and determining roles. In this model, the Committee would make recommendations on priority technical issues and the AEMC would make a final determination. The AEMC would not reconsider technical aspects, only issues of economics, customer impacts and impacts on businesses. The system could involve:

  - Low level technical committees (possibly convened by Standards Australia or possibly working independently) to continue the usual work of detailed technical work and standards development,
  - The Committee making recommendations for adoption of a standard or technical requirement on key issues, which are referred to the AEMC for a determination, and
  - The AEMC approving (or rejecting) recommendations made by the Committee, taking account of economic impacts, customer impacts, impacts on industry and feedback received during consultation.
- The DER Governance / Maturity Plan Committee should be chaired by an independent DER expert.

It is proposed that the DER Governance Committee could be responsible for more than DER technical standards. It could, for example, be responsible for:

1. Setting a vision for the beneficial roles that DER will play as a major part of Australia's electricity generation, storage and flexible resources fleet.
2. Developing a comprehensive program of work to accelerate the practical realisation of the vision in a cost-efficient manner. This could include:
   a. customer protections,
   b. technical standards,
   c. tariff reform,
   d. market access and new market creation,
   e. roles and responsibilities, and
   f. where necessary, the scoping of research necessary to support the above.
3. Regarding DER technical standards, this would include:
   a. monitoring, reviewing and setting DER technical standards,
   b. considering issues related to compliance and enforcement of standards in their development, and
   c. providing advice on standards and undertaking related reviews.

The DER technical standards would be designed or chosen to support electrical system security, distribution network management and affordability for consumers, including through the sale of DER services. The Committee would determine DER technical standards in a comparable way to how the Reliability Panel sets reliability standards. The standards themselves would likely need to be developed by technical expert sub-committees, either established by the Committee or through linkages to existing Standards Australia sub-committees or other bodies. Standards development will be managed to enable full stakeholder engagement whilst keeping pace with the evolving technical needs for DER hardware and software.

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

The ESB Options Paper has not outlined why consideration of the two proposed flexible trading arrangements is a priority. It is unclear what problem this is intended to address. The Options Papers have not proposed a vision, goal or desired end state for the DER sector, and it is therefore difficult to assess whether the proposed flexible trading arrangements would be helpful or a hindrance. The benefits for customers are unclear. We do not understand why this should be considered a priority.

If the Maturity Plan proposal proceeds, the trader-services model is one reform option that could be considered alongside the many other reform proposals that might be prioritised.

We have declined to thoroughly answer questions 22 to 26 regarding flexible trading arrangements. However, some observations made by CEC members in response to those questions include:

- The metering framework is already problematic and is currently under review by the AEMC. We should resolve the issues associated with connecting a single smart meter per site before embarking on reforms for multiple meters.
- Another alternative on the path toward more flexible trading for end-users would be consideration of local use of system charges for the distribution network.

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

The ESB Options Paper has not articulated the case for prioritising 'scheduled lite' over other potential reforms. We do not understand why this should be considered a priority, compared with other potential areas for policy reform.

If the Maturity Plan proposal proceeds, the 'scheduled lite' proposal is one reform option that could be considered alongside the many other reform proposals that might be prioritised.

We have declined to thoroughly answer questions 28 to 43 regarding 'scheduled lite'. However, some observations made by CEC members in response to those questions include:

- 'Scheduled lite' should not be mandatory. It should be left to participants to decide whether the benefits of market participation under the 'scheduled lite' framework outweigh the costs of participation.
- 'Scheduled lite' should be based on the use of web-based APIs. Use of Supervisory Control and Data Acquisition (SCADA) would be prohibitively expensive for small generators.
- Modelling of the likely costs and benefits of participation by a range of market participants should be undertaken before proceeding to detailed design and market reform.

Transmission and Access

The CEC agrees with the ESB that “substantial transmission investment will be needed to accommodate the forecast 26-50 GW of new large-scale variable renewable energy expected by 2040”, and that there are challenges in the current frameworks that mean that transmission is not being built in a timely manner.[7] However, we disagree that the way to address this is by introducing a mechanism for managing congestion. Congestion management will not address the fundamental issue that the necessary transmission is not being built quickly enough. Rather, efforts should be focused on removing barriers to timely transmission and generation investment.

To this end, we broadly agree with much of the ESB’s work in relation to:

- Actionable ISP rules
- Interim Renewable Energy Zone (REZ) framework
- System strength and amending the “do no harm” rules.

However, the benefits of the medium-term access reform options are less clear, for reasons we set out further below. The CEC also remains of the view that the proposed longer-term access reform options will be highly costly to implement and will introduce significant uncertainty for investors.

The CEC recognises the concern held by some within the industry that investment in jurisdictional REZs should not be undermined by the national access framework. That is, there is a risk that the suite of “carrots” intended to incentivise investment by generators in REZs, including a faster connection process and some level of access protection within the REZ, may not be enough to support such investment if access rights do not extend to the regional reference node. In principle, the national access regime should not undermine the objectives of REZs and encourage investment in these locations where it is efficient to do so.

However, the size of that risk is currently unclear. Until the jurisdictional REZ access regimes are bedded down, and given time to operate, it is difficult to assess whether the investment and operational signals these regimes are intended to provide are sufficient to encourage investment in REZs, and therefore whether any changes to investment and operational signals within the national regime are desirable. The CEC is concerned that implementing the ESB’s recommendations for a national access or congestion management regime before giving the jurisdictional regimes opportunity to meet these objectives may undermine incentives to invest in REZs and in the NEM more broadly. The CEC also has some concerns that the proposed mechanisms are not sufficiently well understood at this stage. Further analysis is required before they are recommended to energy Ministers.

As such, the CEC is of the view that at this stage the industry should focus on the development of REZs and providing sufficient investment signals within these zones before any significant reforms to locational signals or congestion management on the broader network are considered. As discussed below, we support the development of a framework for REZs within NSW. By focusing on getting this framework right, it could readily be adopted in other jurisdictions (provided the framework has industry support) to provide a consistent approach to quickly build the transmission infrastructure the NEM needs in a way that supports lower risk and so lower cost generation investment.

Ultimately, the core purpose of this work stream should be to identify the cheapest way to connect new generation to the grid as quickly as possible, and in a way that makes it attractive for investors to participate.

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[7] ESB, Post 2025 Market Design Options – A paper for consultation, Part A, p75.

Interim REZs

The CEC supports the intent of REZ development as a practical and efficient approach to delivering the necessary transmission and generation investment to provide a reliable supply of electricity to customers in coming years. We disagree with the ESB's characterisation of the REZ framework as "a key first step in reforming access".[8] Rather, REZs are about establishing the necessary transmission infrastructure to facilitate the connection of the wind, solar and storage needed to transition the market to clean energy. On this basis, we support the development of REZs as a priority.

We also support the ESB's efforts to establish a coherent and consistent approach to REZs where these are being implemented separately by jurisdictions under state-based legislation.

It is not clear to the CEC that an access regime is necessarily required to encourage investment in REZs. However, noting that some form of access arrangement is required for NSW REZs under NSW legislation, we have supported further exploration of two of the models they are considering that could be workable.[9] Similarly, in response to the ESB's Renewable Energy Zones Consultation Paper we provided initial support for the further consideration of the connection access protection model and the financial access protection model, with the proviso that both models lacked sufficient detail to allow a well-informed evaluation of either at that stage. Generally, if jurisdictions proceed with implementing an access regime within REZs, the CEC supports exploration of arrangements that are simple and provide stability and certainty for investors. Where jurisdictions do choose to implement an access regime within a REZ, ideally all jurisdictions will adopt the same, or very similar arrangements to help avoid any potential inefficiencies that could otherwise be introduced if substantial differences were to arise. The more similar these access arrangements are, the easier it will be for investors to understand and weigh up the relative risks between jurisdictions, and similar approaches will minimise any market distortions that could arise if some jurisdictions were seen to have more favourable access arrangements than others.

In assessing the costs and benefits of any access models, these must ultimately be compared to the status quo of open access, the risks of which are already clearly understood by market participants. In contrast, any access model introduces new costs and complexities that need to be factored into the business case for new projects.

Further, certainty is imperative to support commercial investment at low cost to customers. To that end, the industry needs clear information upfront on the access schemes in order to assess their impact on investment decisions. We note that critical information under the ESB's Interim REZ framework is yet to be defined, such as what generators will receive in return for bidding for access (such as a streamlined connection process).

Congestion Management Model

The CEC welcomes the ESB's decision not to recommend implementing locational marginal pricing (LMP) and financial transmission rights (FTRs) in the short to medium term. However, we remain concerned about the ESB's characterisation of both REZs and the proposed congestion management mechanism (CMM) as a "stepping stone" to a more complex access regime, and the suggestion that there is still an intention to move to LMP/FTRs in the longer term.

For reasons more fully articulated in previous submissions to both the ESB and the AEMC, the CEC does not support the implementation of LMP or FTRs on the basis that it will introduce significant

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[8] ESB, Post 2025 Market Design Options – A paper for consultation, Part A, p76.
[9] See our submission to the NSW Government's *Central-West Orana Renewable Zone Access Scheme – Issues Paper*, dated 30 April 2021 for further details.

complexity for limited benefit. While the CEC appreciates efforts of the ESB to address stakeholder concerns, fundamentally the ESB is yet to provide evidence of a problem of sufficient magnitude that would warrant this significant and costly reform. On this basis, the CEC also does not support the CMM as a first step towards LMP and FTRs.

Further, it is unclear how CMM would transition to a regime with LMP/FTRs, or how CMM as a temporary measure would impact investments with a life span that goes beyond the potential expiration of the CMM. It is also unclear how the longer-term intention to move to LMP/FTRs will impact investment in the interim.

The CEC is also sceptical of the benefits of CMM in and of itself as a measure for addressing congestion. The CMM is intended to improve operational efficiency by incentivising more efficient bidding behaviour. As the CEC understands it, the CMM essentially provides a mechanism for redistributing intra-regional revenues, and has been designed in a way that is intended to result in similar revenue outcomes today under existing tie-breaking rules. As such, the CMM will not result in new transmission investment and so does not address the core issue of accommodating the expected investment in generation between now and 2040.

In addition, it is not clear that the ESB has assessed whether there are any circumstances under which the CMM could result in perverse incentives in relation to bidding. There is an assumption that in removing the incentive to bid at the market floor price, the CMM would necessarily provide incentives to bid at marginal cost. It is not clear this would be the case.

As noted by the ESB, more complicated situations will arise on meshed, as well as looped, networks. This suggests further work is required to fully understand the impact of CMM and so the relative merits of introducing the CMM compared to the status quo. Consequently, the CEC is of the view that the CMM is not sufficiently well understood for the ESB to be able to recommend its implementation at this stage.

Congestion Management Model – REZ version

For the same reasons as above, the CEC does not support the introduction of the REZ version of the CMM at this stage. Further, unlike the CMM model whereby all generators would receive a rebate as well as a congestion charge, this model would essentially introduce nodal pricing for new generators outside of the REZ without providing a means with which to hedge the basis risk. This would expose investors to unacceptable levels of risks.

Locational signal

The CEC remains unconvinced that additional locational signals are required. A number of locational signals already exist, which investors now understand the risks of. These include marginal loss factors (MLFs), potential exposure to congestion and the potential to be constrained off. In addition, the introduction of REZs will provide a new locational signal by making it more attractive for investors to locate within the zones. The CEC considers that the “carrot” approach to incentivising investment via mechanisms such as a faster connection process are more effective than punitive signals that imposed additional costs on generators and, ultimately, consumers.

Rather than introducing new locational signals that will also introduce new costs and complexities, the CEC considers that refinements to existing signals would be more appropriate. This could include, for example, providing access to the modelling for MLFs to improve transparency, understanding and predictability of MLFs. It could also include improved congestion information. A better understanding of where the ESB sees the weaknesses with existing signals could help inform further improvements.

While the CEC does not agree that there is a need to introduce new locational signals, if a new charge were to be introduced, it should be as stable and simple as possible. As such, of the two options posed, CEC members would prefer a fixed, upfront locational connection fee to provide the certainty necessary for projects to be bankable. Any new charge should be as simple as possible. While the charge will need to provide and appropriate signal to support efficient outcomes, we note that estimating either the expected marginal cost of congestion or the efficient cost of transmission infrastructure required as a consequence of a generator connecting will be challenging. This calculation would need to be as simple so as to provide transparency and understanding of likely costs for potential investors.

In respect of generator transmission use of system (GTUOS) charges, we agree with the ESB that this type of charge would result in an unacceptable level of risk for investors. The lumpy nature of transmission investment means that GTUOS could vary substantially, introducing new risks for investors to manage without any obvious means of managing those risks. In contrast, investors require stability and predictability and a means to manage variability.

Other issues

Making the National Electricity Objective fit for purpose

As noted at the start of this submission, the CEC considers that energy market reform should promote a lower emissions future, including by supporting the entry of low emissions technology and ensuring that thermal generation does not remain in the market beyond its operational or economic life. We recognise, however, that the National Electricity Objective (NEO) that the AEMC must use to assess changes to the rules that govern energy markets does not currently factor in environmental considerations. As such, we consider the NEO in its current form is not fit for purpose to support the changing needs of the electricity system as it transitions away from fossil fuel generation to a decentralised, low emission, renewable generation dominated grid. Modifying the NEO to include consideration of wider public policy needs, including lowering emissions, would strengthen the NEO and be in the long-term interests of consumers.

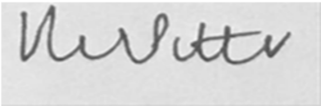
Integrating Energy Storage Systems into the NEM

The AEMC are currently considering their draft determination on the Integrating Energy Storage Systems into the NEM rule change request from AEMO. The AEMC are considering a broad scope of reform through this rule change including the potential to take steps towards establishing a two-sided market. The CEC is supportive of this approach; however, we are concerned that this intent is causing delays to the process to finalise the rule change. There are clear immediate needs that must be addressed through this rule change such as clarifying how co-located storage units can charge from generation without paying the regional reference price, the charging of DUOS and transmission use of system charges (TUOS) and streamlining the registration process for new storage developments.

Significant new energy storage developments are required across the NEM in all ISP scenarios to support the energy market transition. While we support the intent to move towards a two-sided market in the long-term, the immediate needs of the market must be addressed to support the better integration of storage assets and begin the significant investment in new storage developments required. The CEC suggest the ESB consider how the immediate reforms needed through this AEMC rule change are balanced against the long-term desire to move to a two-sided market.

Thank you for the opportunity to comment on this consultation. If you would like to discuss any of the issues raised in this submission, please contact Tom Parkinson, Senior Policy Officer, on (03) 9929 4156 or tparkinson@cleanenergycouncil.org.au.

Yours sincerely,



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