Kerry Schott
Chair
Energy Security Board

9th June 2021

Submitted by email to: info@esb.org.au

Dear Ms Schott,

AEC Response to P2025 Market Design Options Paper

The Australian Energy Council (the "**AEC**") welcomes the opportunity to submit its response to the P2025 Options Paper.

The AEC is the industry body representing 21 electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. These businesses collectively generate the overwhelming majority of electricity in Australia, sell gas and electricity to over ten million homes and businesses, and are major investors in renewable energy generation.

Introduction

The AEC congratulates the Energy Security Board ("**ESB**") upon reaching this phase of the exercise that it has conducted since early 2019, and its recent efforts regarding consultation with industry associations and consumer representatives.

The AEC has engaged in detail with its membership in all matters raised by the Paper. As per our usual practice this submission was developed independently by the AEC secretariat in consultation with its membership, and it develops a narrative consistent with the AEC's fundamental principles that favour competitive markets and risk-facing investments. Unsurprisingly, 21 diverse members are not all of one mind with respect to such large and broad ranging reforms. That diversity will emerge through members' own submissions rather than the AEC's.

The AEC found it mostly useful to follow the ESB's division into four major themes, noting that in some cases the division also creates challenges. This latter point is particularly the case with the Operating Reserve mechanism, which on reflection, the AEC feels has been disadvantaged by its earlier characterisation as an Essential System Service ("**ESS**").

The AEC has responded to most of the Paper's questions in the appendix to this submission. This covering letter draws from broad themes into a form of summary, and also notes some additional key relevant issues that were not identified within the questions.

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Resource Adequacy and Aging Thermal Retirement

Government Investment Schemes

The AEC firmly believes that investment and disinvestment in the National Electricity Market ("**NEM**") should arise through its own intrinsic competitive processes, which it considers best furthers innovation and the long-term interests of customers (and taxpayers). Government should still have a role through the setting of high-level national policy that is implemented by independent national institutions. Carbon abatement is the most significant example where governments should develop such national policy. The AEC otherwise considers government actions taken outside the NEM framework, particularly at a sub-national level, detract from those beneficial competitive processes and are ultimately detrimental to the Australian economy.

The AEC suspects the ESB does not disagree with this sentiment. The AEC accepts however the NEM is in an environment where governments will continue to exercise their sovereign powers through actions inconsistent with the expectations of the Australian Energy Market Agreement. These actions will necessarily be discordant, being primarily motivated by political and parochial interests.

Into this environment the ESB has proposed that governments considering such interventions be first exposed to *principles* and *mechanisms* that will hopefully guide them into designing such interventions in a "least harmful" way. There will however be no way to enforce such initiatives, and, because they can only be a guide, the initiatives will likely be substantially compromised in order to reduce the high probability that they will be ignored.

The AEC supports the ESB developing *principles* to identify the "least worst" forms of government intervention in the areas of investment, disinvestment and the expansion of transmission. Such principles should always be bounded by an explicit recognition that the NEM, when left alone, will deliver such things more efficiently.

With respect to *mechanisms* where national institutions become directly involved and help plan, such interventions, the AEC considers this a step too far. Whilst not disagreeing that these institutions' expertise could help avert some mistakes taken by government, the AEC does not consider this an appropriate role for them. Such assistance will be seen as a tacit endorsement and will conflict with the institutions' critical roles as independent umpires under the NEM's rules.

Additional Disclosure Requirements on Thermal Generation

It is essential existing generation feels confident in exploring new operating regimes and innovations in response to new market signals that arise through the transition. Having the freedom to do so will undoubtedly assist a secure transition to a cleaner future, and the AEC is pleased to note the ESB shares the same view.

It is then confusing as to why the ESB feels it is necessary for generators to telegraph more information about their operating regimes than is already the case in the existing rules. These rules already require generators to provide their planned level of capacity available to be operated in the market, in declining levels of granularity, from 5 minutes ahead to their expected ends of life. All this information is published, supporting an efficient market response.

This already provides the information that is required for reliability analysis:

- Temporary mothballing and two-shifting are irrelevant to reliability if the plant is capable of returning in response to market signals or Australian Energy Market Operator ("**AEMO**") intervention – as required by the rules and the maintenance of market registration.
- In unusual situations it can assist AEMO's security management to obtain more detailed confidential information, such as recall times, but AEMO already has this power and exercises it to its satisfaction.

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New disclosure requirements of dubious value carry an administrative cost. But more insidious is their interference with generators' operational innovation:

- Generators will feel less inclined to seek innovative new approaches when they must be shared with competitors;
- Generators know that changing their operating plans in a beneficial manner will involve a regulatory burden of explanation and justification, such as is already being seen in the present 42 month notice of closure arrangements[1]; and,
- Having created a publication process, it seems likely that when generators adjust their inputs, the accuracy of the forecasts will be criticised, that will in turn invite regulatory action to "lock in" forecasts in some way. This will then restrict generators' ability to nimbly respond to the needs of the transition.

The Options Paper does not articulate what exact benefit the publication of this new information is designed to achieve.

Financial Retailer Reliability Obligation
Whilst AEC members have a wide range of views on alternative Resource Adequacy Mechanisms ("**RAM**"s), there is a universal doubt the present Financial Retailer Reliability Obligation ("**FRRO**") is achieving benefits beyond its costs. A widespread view is that if a substantial alternative RAM is introduced, such as Operating Reserves or a physical capacity arrangement, then the ESB should feel confident to retire the FRRO. There is also a view that FRRO could be retired even if the ESB recommends retaining the energy-only market with a higher price cap.

In any event, the AEC opposes expanding the burden of the FRRO, particularly through the removal of the double gate (T-3 and T-1) trigger. That would be a diversion from its original intent as a mechanism only to operate in a circumstance of a reliability shortfall that is well telegraphed but not acted upon. Operating only on a T-1 trigger creates unmanageable risks for participants, for example where a vertically integrated player suffers an unforeseeable unit breakdown just prior to T-1. Such events were intended to be dealt with through the NEM's existing emergency reliability mechanisms rather than FRRO.

Should the FRRO be retained, the AEC considers the Market Liquidity Obligation can be entirely removed. There are some further adjustments proposed in the Response appendix.

Alternative Resource Adequacy Mechanisms
The ESB appears to have open to it a graduated level of options for change in this area:

- The retention of the energy-only market supplemented by the FRRO and market setting changes over time.
- The above with the inclusion of an Operating Reserve mechanism in order to provide some additional value to reserve capacity.
- Creating a decentralised trading capacity market through conversion of the FRRO into a Physical Retailer Reliability Obligation ("**PRRO**").
- Introduction of a centralised physical capacity market (noting this option was not progressed at the Directions Paper stage).

The AEC membership incorporates a range of views across the spectrum above. Whilst noting the majority of competitive investors prefer the more minimalist options – being the first two of the above - the AEC rejects any suggestion these firms do not appreciate stakeholders' utmost concern for a reliable transition. Nor are the differences of view evidently linked to firms' technology investments, size nor vertical integration. To the AEC's mind the full spectrum of views have merit and express different philosophies of how an efficient level of reliability can be retained through the transition at least cost.

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[1] https://www.aer.gov.au/wholesale-markets/notice-of-closure-exemptions/76484-agl-macquarie-pty-ltd-liddell-unit-3-exemption

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Market Price Cap
With respect to pursuing the existing design, there is a perception that the P2025 has not sufficiently investigated its ability to support the transition through the market price cap rising closer to the average value of customer reliability.

It is noted the modelling techniques previously employed by the Reliability Panel have suggested that the permanent reserve standard of 0.002% Unserved Energy is sustainable with a price cap at the current level. A legitimate conclusion of the P2025 is that there is insufficient confidence whether the classical modelling approach is appropriate through the challenges of the transition and in the presence of external investment distortions. Thus the Panel could be directed to take a more reliability risk-averse approach in the current review cycle.

Operating Reserve
In 2020 the AEC supported further work on the Operating Reserve concept, which was then seen to have both RAM and ESS benefit. The ESB moved it for further study into the ESS stream which appropriately explored its ability to support short-term supply/demand balancing and ramping. This work is uncovering that the existing market incentives appear adequate for balancing and ramping, even in light of changing technologies, as long as the market continues to deliver sufficient underlying capacity and storage energy volume. The AEC does not disagree with that conclusion.

However, that ESS stream did not explore the Operating Reserve's ability to provide a RAM mechanism. The Operating Reserve has a RAM effect by adding some additional spot market returns to a peaking plant that sits just outside the dispatched merit order during moments of low reserves. Some AEC members have their own preferred designs of Operating Reserve, which have not all been raised through the ESS investigation. Further, if exploring Operating Reserve purely for its RAM benefit, it may be appropriate to reconsider it in its simplest form, which is Standing Reserve (i.e. peaking capacity intentionally withheld from the market) which was last considered by the Australian Energy Market Commission's ("**AEMC**"s) Reliability Frameworks Review.

Physical Retailer Reliability Obligation
The PRRO is a form of capacity market. The merits of energy-only versus capacity markets is an enduring debate for electricity markets. Like all capacity markets, the level of required reserves, and the eligibility for delivering and transporting capacity, will be determined centrally under the PRRO. Capacity markets are seen to provide additional stakeholder confidence, as the market operator explicitly purchases physically observable reserve, but are also seen to be more expensive and reliant on very difficult deterministic assessments of plants' contributions to reliability.

The AEC sees this as a fundamental change to the NEM, yet the Options Paper has presented it as an incremental adjustment to the FRRO. This is an unreasonable characterisation.

In the AEC's mind, such a reform requires much more detailed development, socialisation and quantification than has yet occurred. For example, the Options Paper has not yet explored fundamental elements such as how intra and inter-regional transmission access would be considered when allocating capacity rights.

A fulsome exploration would take many more months. For this reason the AEC cautions against an irreversible decision for or against PRRO by mid-2021. Should, following feedback, the ESB be supportive of the PRRO model, the AEC recommends it be referred to the AEMC for development and its ultimate recommendation following that work.

Despite the diversity on RAM models, the AEC membership is united in a view that the introduction of a form of capacity market or operating reserve should not lead to a lowering in the market settings towards the levels seen in other capacity markets. PRRO proponents see ongoing spot market risks as essential, and if retained, could avert some of the criticisms of other capacity markets. In particular these low price caps lead to:

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- weak incentives for accredited plant to perform at times of peak;
- under-utilisation of demand-side response; and,
- insufficient valuation of the depth of energy storage.

Centralised Capacity Market
The AEC recognises that, in 2020, the ESB chose to discontinue work on the more conventional form of capacity market (such as that employed in the Western Australia Wholesale Electricity market ("**WEM**") as it was seen as the largest step away from the current arrangements. The AEC broadly supported that view at the time.

However, upon reflection, it is worth considering whether the PRRO's decentralised trading of capacity certificates creates more than just a veneer of decentralisation. The fundamental decisions in any capacity mechanism are:

- how much capacity is required with respect to forecasts of demand, usually implemented as a deterministic "reserve margin"; and,
- the conversion of assets' naturally probabilistic characteristics into deterministic reliability certificates.

All capacity designs, including the PRRO, necessarily move these key judgements from investors into the market operator and shift downstream the financial consequences of error in these judgements. That is the key difference between capacity market designs and an energy-only market.

In a fully centralised design such as the WEM, the market operator centrally purchases the certificates that result from these judgements on behalf of the customer. This seems simpler from a transactional point of view. In comparison to the PRRO, it is not clear from the ESB's material how the decentralisation of certificate trading alone exposes investors to any particularly valuable performance risks in comparison to a conventional capacity market like the WEM.

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Essential System Services and Scheduling and Ahead Markets

Missing Markets
The AEC maintains the "missing markets" component of the ESS line of work is the most urgent in the NEM. In contrast with the healthy reliability outlooks in AEMO's Electricity Statement of Opportunities, AEMO's Renewable Integration Studies indicate clear and present dangers in maintaining a secure system without these markets. Nor is the AEC aware of any stakeholder doubt as to this view. Despite this, the component struggles to achieve the high-level focus that such urgency implies, presumably due to its "eye glazing" nature[2].

The most urgent part of the P2025 review is therefore the creation of markets for primary frequency control, inertia, fast frequency response and system strength. In 2020 the ESB delegated these themes to the AEMC who had received related rule changes. As a result, the Options Paper has given these matters negligible coverage and they do not appear in any of the 100 questions. The AEC supports delegation to the AEMC, that is making progress on all but the inertia market, but is disappointed by a lack of visible support from the ESB.

In particular the AEC is concerned about when and who will develop a mechanism for the valuation of inertia, which was recognised as a missing market by the ESB in 2020 and appears in the planning in figures 7 and 3.6 (page 54). The AEC notes, however, that the section "Inertia Spot Market" (page 52) does not actually discuss potential designs of an inertia spot market nor who and when it will be taken on. Instead it focuses upon the present stop-gap arrangements of interventions and structured procurements, which in context appears to endorse their permanence. The AEC disagrees with that position.

The AEMC is not evidently progressing work on an inertia market at this time despite it having one related Rule Change before it[3]. Exploration of a permanent inertia mechanism thus appears to be sitting dormant between the institutions. The AEC is separately progressing its own research in a hope to trigger action, but would prefer the ESB direct development in order to fully engage the expertise of AEMO and AEMC.

Scheduling and Ahead Markets
The AEC considers this area a second-order issue in comparison to the missing markets theme, despite it dominating the Options Paper's ESS chapter, and suggests its emphasis and resources be partially redirected to development of an inertia market.

The AEC broadly supports the shift in direction for this activity since mid-2020, with the more radical proposals of fully centrally-committing the energy market since being set aside. The AEC strongly supports the principles of a self-committed energy market as presented in the consultancy advice attached to its previous submissions[4].

The AEC fully supports AEMO building sophisticated tools to permit it to most effectively exercise the levers that the Rules provide it when scheduling the energy market, which include calling upon structured arrangements, and, as a last resort, intervening. It is not clear to the AEC, however, why this task is considered multi-institutional as it does not, at face value, require any new powers or Rules for AEMO.

The AEC supports the use of Network Support Agreements ("**NSA**"s) as an alternative to network infrastructure where efficient. NSAs however should be long-term, providing income certainty to the provider as a result of good network planning well ahead of time. After a long-term NSA is engaged

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[2] Energy Security Board Media Release 12.01am 30 April 2021
[3] https://www.aemc.gov.au/rule-changes/synchronous-services-markets
[4] See https://www.energycouncil.com.au/media/eginmtjb/20200630-cec-final-report.pdf and https://www.energycouncil.com.au/media/gi1j4v2j/cec-report.pdf

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by the network company, AEMO might then use a sophisticated tool to determine when to dispatch it, say using the proposed Unit Commitment for Security ("**UCS**").

The AEC is concerned at the discussion in System Services Mechanism ("**SSM**") theme which appears to imply that instead of a long-term procurement approach, the ESB sees a future where services will instead be bought from non-network providers on a short-term, day to day context. This would undermine the need for prudent network planning, would be more difficult for providers to bank and would not lead to a fair comparison of network and non-network alternatives. It is likely to also more commonly fail (or be exposed to the appearance of monopoly pricing) and end up falling back to AEMO's powers of direction. For these reasons the AEC suggests the SSM should not be further progressed until a clearer need for it emerges and there is confidence that it will not undermine long-term NSAs.

With respect to the objective function of the UCS and SSM, the AEC understands that it is intended to both:

- ensure the system remains secure, and,
- improve the overall efficiency of trade.

There is however a risk that when a committable ESS resource also provides energy, that the second objective function will naturally seek to commit resources for purely energy purposes: effectively creating a centrally-committed energy market. The AEC understands that is not the ESB's intention, and it may have to constrain the circumstances where these tools recommend committing such plant. For example it could trigger only when specific constraints bind.

Operating Reserve
The AEC supports the efforts to date to explore the short-term ramping and supply/demand balancing benefits of Operating Reserve and does not disagree with the preliminary conclusion that these requirements will most likely continue to be adequately provided through the existing incentives. The AEC however considers Operating Reserves' likely benefits emerge in the RAM theme and should be explored therein. Further comments exist in that part of our submission.

Integration of Distributed Energy Resources and Demand Side Participation

As consumers continue to make investments in distributed energy resources ("**DER**") and other technologies, there will be a need for the market to develop new technical and regulatory approaches to maximise the benefits these technologies can enable. While the AEC is seeing highly engaged consumers seeking to challenge the current regulatory and market frameworks today, for the vast majority, there is no clear market failure that is identifiable and warrants immediate reform.

The AEC encourages the ESB to take a 'just in time' approach, led by consumers demand for, and availability of, technology that enables flexible demand. The Options Paper goes beyond this, and seeks to develop new solutions that solve potential problems, rather than seeking to monitor and identify gaps in the frameworks. Consideration of Option 2 "Flexible Trading Relationships" is an example of this 'build it and they will come' approach. While the ESB notes that Option 1 is yet to be implemented and should minimise the technical barriers to customers seeking to enter into more flexible trading relationships, it already seeks to rebuild the system to enable a theoretically cheaper model for customers to utilise.

Pre-supposing how customers will utilise technology and its impact on the electricity system risks building in significant redundancy. This is analogous to the expansion of electricity networks caused by an error in assumptions of the growth in peak demand. As cooling efficiency improved, and customers increasingly installed solar PV, peak demand growth slowed considerably, resulting in substantial regretted network expenditure.

Evolving Frameworks Through a Maturity Plan

Given this unknown future, the AEC supports the ESB's approach of developing regulatory and other market changes through the use of an iterative Maturity Plan. The Maturity Plan will allow market bodies, industry, and consumers to identify and prioritise necessary reforms as the enabling technology evolves, and mitigate unnecessary system cost. While the Maturity Plan approach necessarily brings with it some challenges and additional bureaucracy, these can be mitigated through a carefully designed governance approach.

In the electricity market, the rule change process must remain sacrosanct, and the Maturity Plan must not be undertaken in a manner that circumvents or obfuscates this process in any way. The AEC is concerned that development of reforms within the Maturity Plan framework might encourage the market bodies to avoid some of its usual scrutiny on the benefits or costs of a reform. Given the Maturity Plan is unlikely to be as openly consultative as a rule change process, the AEC recommends consideration be given to whether the Maturity Plan could be ring-fenced from the market bodies usual functions to an extent, to enable genuine scrutiny of rule and procedure changes.

Customer Choice and Protections in the Energy Transformation

Choice is critical in a competitive market, but the AEC does not consider this means a customer must be able to switch between suppliers of DER technology and services in the manner in which they switch retailer today. It is important to note that the ability of retailers to develop innovative products and services today has been inhibited by desires of policy makers to reduce barriers to switching to as close to zero as possible. Fixed term contracts, and early termination fees in particular, are virtually non-existent in the small customer market due to governments ruling them a barrier to a customer switching to a cheaper deal. Retailers are therefore limited in making offers to customers that seek to maximise their engagement over a period of time, and rather, needing to ensure that all benefits are maximised immediately so as to avoid a customer switching away. The AEC is concerned that the ESB is approaching switching with DER or demand side participation ("**DSP**") in the same mindset. Today, DER contracts – particularly those with high cost enabling technology like batteries – are highly dependent on the provider of the goods subsidising or maximising the value of the asset over its lifespan. As an example, a virtual power plant ("**VPP**") might offer a cheaper battery to a customer on the proviso that it will be able to control and discharge that battery during its lifespan. In an environment where a customer could simply switch VPP

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providers, it is likely the full cost of the asset would need to be paid upfront to enable this optionality. It is questionable if this is a benefit to consumers at this early juncture of DER maturity.

Given that, the AEC encourages the ESB to avoid making any suggestion as to approaches to better enable switching until such time as there is adequate maturity to understand the objectives and benefits of greater engagement. In the meantime, the Maturity Plan could be utilised to better understand that variety of approaches considered in the Options Paper with further reforms considered at such a time as a clearer path forward becomes evident.

The AEC welcomes steps by the ESB to develop a risk assessment tool to identify the need for additional consumer protections as the market evolves. This approach will allow stakeholders to be comfortable that reforms will not unreasonably disadvantage consumers who either wish to engage, or do not. However, the tool focuses strongly on the benefits to consumers of increased protections, rather than the benefits of appropriate consumer protections. Importantly, costs are a key driver to identifying the appropriate level of consumer protections, yet are not considered within the tool itself. It appears that the ESB is assuming a resulting rule change process will seek to critique the benefits and costs of a change, and therefore identify if additional consumer protections are warranted. The AEC disagrees with this approach, and considers that iterative assessment of costs, within the development of the reform, will benefit both participating and non-participating consumers. An iterative approach enables protections to evolve, and be more fit for purpose than a single assessment of the proposed protections against the National Electricity Objective ("**NEO**") or the National Energy Retail Objective at a later date.

Tariff and Regulatory Changes
The AEC considers better alignment between network tariffs and the desired outcomes of this workstream will result in a significantly enhanced outcomes for consumers. To date, tariff reform has centred on developing economically efficient network tariffs at the national metering identifier ("**NMI**") level to solve issues around peak demand. Complex tariffs are hard to sell to the majority of consumers. Given this, the AEC welcomes discussion of portfolio level tariff charges to enable retailers to identify and offer more complex products to a specific subset of their customer base. Similarly, it will incentivise retailers to better participate in tariff reform to a greater extent than they do today. Today, retailers are incentivised to mitigate the harm their customers will face from changes to their tariff structure. Demand tariffs and other punitive tariffs designed to discourage use at peak times have the potential to cause bill shock, and as such, retailers will seek to dampen their signals should they be asked to implement them. On the other hand, with portfolio level tariffs, retailers would be able to directly work with the network and their customers to offer innovative products, or a suite of products to customers within that area.

Flexible Trading Relationships
The AEC considers Option 1 is a necessary first step to identifying whether there is a genuine desire for additional competition within a single premises. The AEC opposes steps at this time to further develop Option 2 without first identifying if customers are willing to pay for increased access to the market. While Option 1 likely sees a higher upfront investment for customers who wish to participate in flexible trading relationships (FTR), Option 2 likely passes additional costs onto other consumers, with retailers and other market participants required to make investments in their systems and processes to facilitate the reform.

That being said, there are other reforms that might enhance the benefits of Option 1 without structural changes to market frameworks. For example, network tariffs could be reformed so that only a single fixed charge is charged to a single site. Currently, customers with two NMI's are required to pay two sets of fixed charges, even though it is likely only one meter will be in use at any one time. Simple amendments such as these could facilitate greater take-up of FTR if customers want it.

Scheduled Lite

There are many benefits to the market to having greater visibility and scheduling of demand side loads. Similar to the benefits from increased scheduling on the supply side, understanding the likely demand and the variability of that demand will increase efficiency in the system, improve reliability forecasts and likely lead to reduced costs for consumers.

However, these benefits come from having visibility of a significant percentage of the large loads within the NEM. The AEC does not think this outcome will eventuate through a voluntary mechanism such as the visibility or dispatchability models details in the options paper. While these models might be a useful trial for a mandatory scheme in future, without clear direction from the ESB that a mandatory approach will be implemented in a set period of time, the AEC ultimately considers take-up of scheduled lite will be negligible, and therefore reduce the benefits of its implementation.

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Transmission and Access

The AEC notes the repeated use of ESB language that describes a large and widespread transmission build as *essential* to the energy transition. The AEC considers an efficient NEM transition will include considerable new transmission investment, but urges decision makers to recognise that transmission is a *choice* and not a *pre-requisite* to the transition. A secure, reliable and low-carbon power system can also legitimately be achieved with negligible new transmission, through reliance more on local sources of renewable supply, storage, peaking and distributed options. The question is not whether either approach can be done, but which ultimately has the lowest total cost.

This choice should only be exercised after carefully weighing up the costs associated with options to either build transmission or rely on local sourcing. Indeed this is what the Integrated System Plan ("**ISP**") does when it considers "with" and "without" cases: it may conclude the "without" case is less cost-effective, but it never suggests that it is untenable.

Allowable Benefits

The AEC is very concerned by the emergence in the "Key Points" on page 75 a suggestion of revisiting the allowable benefits in the Regulatory Investment Test for Transmission ("**RIT-T**"). The RIT-T has been reviewed many times previously which have confirmed that its present structure incorporates the appropriate market benefits for use in assessing monopoly infrastructure build. Furthermore, this has not been previously raised in the P2025 review and its sudden emergence at this late stage as a "Key Point", and with negligible supporting rationale, does not represent good regulatory practice by the ESB.

The suggestion of the ESB supporting inclusion of "social benefits" is particularly disturbing. These have correctly been rejected in previous RIT-T assessments as they are both entirely inconsistent with the NEO which is the long-term interests of electricity consumer who pay for these investments) and because they are highly dubious and easily politicised. Furthermore they do not consider social dis-benefits that occur elsewhere when a network enhancement shifts activity from one place to another.

It is important to recognise that market investments are made around the development of a transmission network, and that every investment will itself create winners and losers. Despite the inevitable creation of losers, the AEC nevertheless supports monopoly network investments going ahead where they are demonstrably cost-effective. However this must be done in the context of a highly trustworthy and predictable cost-benefit framework. To do otherwise not only leads to inefficient use of customer money, but also undermines the predictability of market investments[5].

Contingent Project Approval

Another item that has emerged in the "Key Points" is the potential bypassing of the entire RIT-T process for ISP recommended projects, and instead moving directly to Contingent Project Application ("**CPA**") stage. The AEC supports removal of duplicative sequential processes, however the ESB has not yet shown whether key features of the RIT-T are fully captured within a CPA and whether within a CPA the networks are required to consider other options, especially non-network options.

Further, some ISP projects may not be contingent projects. The AEC considers a specific cost-benefit assessment before the regulator is essential for each large separable investment.

[5] For further explanation of this issue, see https://www.energycouncil.com.au/analysis/building-transmission-in-a-market/ and https://www.energycouncil.com.au/analysis/customer-benefits-don-t-necessarily-benefit-the-customer/

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Access Options
As stated in its 2020 submission, the AEC accepts that the existing open-access regime and regional pricing is theoretically inferior to approaches used in some other markets. The challenge however is that after 23 years the market is heavily invested in the current arrangements and therefore any change will come with very large costs and value transfers that have to be weighed against the benefits of change.

The AEC's membership unanimously considers the costs and disruption caused by changes to the access regime will be very large and as such any change should occur with a long-lead time, and therefore most likely not before the end of the 2020's. There is diversity however about whether the benefits of committing to a new model in the long-term would exceed the costs.

The AEC has considered the numerous "short-term" options presented in Part B, which all have various complexities, advantages and disadvantages and are critiqued in the appendix. The AEC also notes the ESB's desire to progress global Locational Marginal Pricing/Financial Transmission Rights ("**LMP/FTR**") in the long-term, say by the early 2030's. The AEC sees inconsistency between the short-term options and the ESB's long-term plans. Centralised options such as Generator Transmission Use of System charging would seem to be significant deviation from an LMP/FTR direction.

From an over-arching perspective, the AEC considers that if the ESB is to commit to its preferred long-term model, it should now nominate a firm date, beyond the 2020's. A long-term signal would result in:

- new investors taking it into account when locating plants – the ESB's apparent primary objective in recommending LMP/FTR;
- network providers understanding the long-term arrangements when designing Renewable Energy Zones access arrangements; and,
- incumbents having due time to prepare for the very large change.

In the intervening period the ESB should not need to distract from this long-term reform by progressing any of the short-term options.

Any questions about the integration of the integration of DER and DSP in this submission should be addressed to Ben.Barnes@energycouncil.com.au. For all other matters, to Ben.Skinner@energycouncil.com.au.

Yours sincerely,

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Attachment: Questions for consultation paper

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ESB Options Paper Summary of questions for consultation

Questions for consultation paper

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<tr><th>#</th><th>Questions</th></tr>
<tr><td colspan="2">Part A</td></tr>
<tr><td colspan="2">Chapter 2 - Resource Adequacy Mechanisms</td></tr>
<tr><td>A1</td><td>What types of information provision regarding jurisdictional investment schemes would benefit participants the most?

The AEC considers new investment should only emerge through signals intrinsic to the NEM and those new investments should be fully risk-taking. Government investment schemes undermine the NEM's investment mechanisms. The ESB has implicitly recognised this in this question and should do its best to explain the consequences of such schemes to jurisdictions.

To the extent jurisdictions persist, the sorts of information that market-facing investors would require include:
The size of the scheme.
The desired technologies.
Locational expectations and how it interacts with the network planning regime.
The financial characteristics of scheme, in particular which markets signals/risks are removed, and which are retained.
The funding of the scheme and what limits apply to the potential scale of liabilities.
Inclusion of information into AEMO's generation page:
Even before jurisdictions have invited tenders, the "publicly announced" category can be used to describe the expected outcomes of the policy; and
As the scheme moves into engaging with generators, the government itself should ensure that specific projects move into the "advanced proposals" category.</td></tr>
<tr><td>A2</td><td>Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?

The NEM's design assumes that investments will be exposed to the intrinsic signals of the NEM, and that investments' risks should not be transferred to taxpayers or captive consumers.

In general, the least distortionary form of subsidisation is a type of cash grant, or certificate scheme, that leaves the generators fully exposed to market signals. Contracts for Differences or Put Option type arrangements that immunise the generation should be avoided.

There is considerable danger in schemes that remove the risk as, at worst, it can interfere with efficient dispatch and create system security issues. At the extreme, this is evident in the Australian Capital Territory renewable scheme which immunised recipients from both loss factors and negative prices. As a result, these generators exacerbate oversupply conditions and large financial losses are being incurred during negative prices.

Other schemes tend to incentivise maximum energy production over time and do not link to the needs of the market, for example, they do not discourage investment in equipment that cuts out during rare high temperatures.

In order to operate effectively, the schemes should:
Retain exposure to spot price:
Incentive to reduce output in negative prices</td></tr>
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	○ Incentive to maximise capability at high demand times, e.g. high temperatures • Retain exposure to ancillary services costs: e.g. causer-pays. • Retain locational incentives: exposure to congestion and loss factors. Further, the generation they produce should be put to good use. If the generation is contracted to government, the government should attempt to offload this position into the market, thereby providing some upstream hedging that retailers can repackage.
A3	*Are there financial principles missing, or that have been included but shouldn't be?* Jurisdictional schemes would be best to operate as a competitive cash grant for the desired technology and otherwise not transfer any ongoing risks away from the investor to customers or taxpayers.
A4	*What are some of the market-based signal challenges, if any, with mothballing / seasonal shutdown?* Mothballing/seasonal shutdowns of coal plant is beneficial to the transition and should not be discouraged in any way. Plants should retain maximum flexibility to enter or exit mothballed status quickly as conditions change. Plants should never be required to "lock-in" a status ahead of time, which will interfere with the flexibility of the market that will be essential to reliably and to securely manage the transition. The ESB's focus on this matter appears to imply a suspicion that mothballing is a form of unannounced closure and a gaming of the notice requirement. This is not the case. To retain NEM registration, generation must routinely show the AER that it is capable of meeting all the technical requirements of the Rules. This implies that the generator is capable of operating when market conditions justify it or AEMO directs it. The existing STPASA, MTPASA and EAAP arrangements satisfactorily publish generator intentions with respect to PASA availability to run (<24-hour recall) when market conditions warrant it. There are situations where AEMO requires more detailed information from plants for their own security management, e.g. detailed recall times and fuel management. AEMO has the power to collect this and routinely does. There is no need for such confidential information to be otherwise published.
A5	*What additional costs or process burden may the disclosure of such information place on stakeholders?* There will be an administrative burden of an often inane nature, such as a recent application to reverse two units' closure timing[1]. But the bigger cost the compliance risks in describing what is an inherently complex and uncertain position, e.g. the predicted availability of a fuel, into a simplistic deterministic description. It is very difficult to find an expression that entirely suits the market rules of the true and complex condition of an asset. Then, when an adverse event occurs, it is common for a regulator to identify participants whose inputs did not meet its own hindsight judgement of compliance with such rules[2]. Ultimately the response to this situation will be a cost that is difficult to identify: risk-averse behaviour. Generators will be discouraged from entering innovative operating regimes that will assist the transition for fear of being non-compliant because there is no pre-existing regulatory description for that innovation.

[1] https://www.aer.gov.au/wholesale-markets/notice-of-closure-exemptions/76484-agl-macquarie-pty-ltd-liddell-unit-3-exemption

[2] An example of this situation can be found here: https://www.aer.gov.au/news-release/pelican-point-in-court-for-alleged-breaches-of-national-electricity-rules

A6	*What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?* The fundamental information – availability on short recall - is already published in MTPASA and EAAP. The AEC sees no justification to increase these powers. The detailed operational modes of plants are, by its nature, confidential and revealing them puts generators at a disadvantage in negotiations with fuel and maintenance suppliers. Furthermore, revealing innovative operational strategies to competitors removes the advantage in exploring innovation.
A7	*Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?* Yes, particularly where: • Process for alteration is cumbersome; • Justification or approval is required for every change; • Uncertainty over the definitions of what is mothballing; • Triggers a reporting requirement e.g. one to jurisdictions; and, • Reveals confidential information to competitors or suppliers.
A8	*Do stakeholders agree the notice of closure exemption process should be extended to include mothballed generation? If so, should it apply to all generators or just to large designated thermal generators?* No, as discussed previously, the notice of closure adequately captures the capacity to operate the unit should market conditions value it, or AEMO direct it. The ESB's focus on this matter appears to imply a suspicion that mothballing is actually a form of unannounced closure and thereby a gaming of the notice requirement. This is not the case. To retain NEM registration, generation must routinely show to the AER that it is capable of meeting all the technical requirements of the Rules. This requires that the generator is capable of operating when market conditions justify it or AEMO directs it.
A9	*What suggestion do stakeholders have for defining mothballing?* AEMO and the Reliability Panel have already defined this. See section 1.5 of *Template for Generator Compliance Programs*.
A10	*How can governments, market bodies and market participants better work together to be prepared for exits?* The existing information processes and closure rules already provide a strong platform for understanding and preparation. AEC would be comfortable with AEMO performing an additional system risk assessment report as an adjunct to its MTPASA, ESOO and ISP work, and published. This should require no new information from participants and cover matters of security and reliability, but not price. AEC considers it would be inappropriate to use institutions' resources and information gathering powers for the purposes of assisting governments with their market interventions.
A11	*Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?* The AEC's position is that governments should not intervene in market. Existing market forces, and possibly new RAMs, reinforced if necessary by AEMO intervention, should be allowed to work through.

	AEMO interventions are preferable to government interventions because they occur through a managed rule-based process and are designed to be lowest cost, and to have least distortion to the underlying market. For example, they employ "what if" pricing that attempts to avoid such interventions perversely suppressing price. AEMO already has the power to intervene where reliability falls below the reliability standard by seeking RERT offers, or if absolutely essential, directing. If it is necessary for reliability to extend a plant's life beyond a commercial closure, then contracting it via a RERT contract is the least distortionary. AEMO is unable to extend a plant's life purely to suppress price, which is appropriate.
A12	*Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?* The AEC preference is that governments do not such enter contracts. If a reliability shortfall should emerge, AEMO will use its intervention powers and conduct RERT contracting. This is the preferable way such a contractual extension should occur. If governments nevertheless enter a contract, this should be kept separate from all market activities, including RERT. AEC does not support ESB proposing any structure of such contracts. Governments should not be invited to intervene in either the normal energy market, nor the market for RERT contracts.
	Chapter 2 - RRO questions
A13	*Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?* The six Principles (pg. 32 Part B) appear appropriate and consistent with work completed by the AEC which the ESB is encouraged to consider.[3] The AEC suggest including a principle regarding furthering retail competition and innovation. The AEC also supports the 3 minimising cost objectives.

[3] https://www.energycouncil.com.au/media/jzrpgxsb/market-design-principles-final-report-180419.pdf

A14	*Are there any obvious priorities given current and plausible likely future market scenarios?* A priority which is not yet clear from the ESB's material is a consideration of the workability of the existing RRO, and its potential replacements, within the future technology paradigm of the NEM. In particular its much more stochastic and energy-limited characteristic which is not evidently compatible with such schemes. Whilst the real power system has always had probabilistic characteristics, a power system based on traditional generation technologies, combined with a short-lived extreme peak in demand, could be reasonably accurately simplified to a deterministic capacity calculation. That is the fundamental premise for the design of the existing RRO and all capacity markets. However this premise is arguably no longer fit for purpose in many power systems and will soon become universally obsolete. The probabalistic character of the future power system is emergent on many fronts: • The use of deterministic "discount factors" for wind generation is a gross simplification of its true value to the power system. As the share of wind grows, and its generation diversity characteristic becomes more complex, the use of a simple figure presents real risks to accurate reliability forecasting. The usual approach when faced with such risk is to apply ever more conservative discounting, often without scientific merit, leading to considerable undervaluing of the resource. • The development of an active demand-side, which is capable of responding to market signals, but does so in a probabilistic manner, i.e., it is not "firm" to all conditions, similarly makes determining a single reliability MW value extremely uncertain and often misleading. • The introduction of storage assets that have a relatively low capacity to energy cost ratio leads naturally to an energy-limited power system. Yet all the RAM designs, including the exiting RRO, assume unlimited energy is available from all accredited capacity. The designs have no way to assess energy over time. Some capacity markets have responded by applying extremely conservative deterministic de-ratings based on the energy available, but this is also incorrect, because a storage, with, say, only 2 hours stored energy, would be perfectly adequate to support reliability in some situations, although not in others. • The future transmission system will be much more naturally congested than one designed around conventional generators. This is entirely appropriate: it is efficient to for the capacity of transmission to areas of stochastic generation to be sit well below the sum of their nameplate capacities. However this means a deterministic simplification of reliability that ignores access will prove materially incorrect. • The premise of adding up deterministic capacity values to compare against an extreme demand peak will not be meaningful in the future power system. Customer demand will be a much less significant factor in future reliability. The more significant factors will be the availability of renewable energy over an extended period. In other words, the future power system will be more stressed by calm winter weeks than the evening of a 40 degree day. It is not clear whether any of the ESB's new RAM designs is capable of engaging with the future power system's true pinch points. Those being considered appear designed to reinforce the reliability of the old power system, rather than the new.
A15	*What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?* The purpose of this question is unclear: the paper makes no suggestion that retailers are failing to comply with the existing Financial RRO, nor to the AEC's understanding

	is the any evidence of such. Why is there a suggestion that the ESB needs to encourage greater compliance than already exists?
A16	*Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?* AEC members have mixed views on whether a Physical RRO is better suited to the transition than existing arrangements. Members generally agree that the existing arrangements could deliver the transition where governments are supportive of the necessary characteristics of those arrangements: • Volatile energy prices that are allowed to rise in response to market conditions, and • An efficient level of reliability, such as 0.002% USE, rather than something inefficiently conservative. If these two key (non-physical) features do not hold, then members agree the current arrangements will be challenged. That could require a new RAM, or it could be resolved through progressive increases in the Market Price Cap.
A17	*[Financial RRO option] How could you strengthen the signal? Could minimising the triggers do this? What are the unforeseen consequences or implications with this?* The AEC considers that in the current NEM, reliability is achieved largely through the energy-only pricing signals, contracting and ultimately AEMO intervention. The AEC recognises that the Financial RRO provides some assurance to governments and institutions that prudent contracting is occurring, but remains doubtful that this benefit exceeds its costs. The premise of the question "How could you strengthen the signal" is unclear: There seems no basis or evidence presented as to the apparent conclusion that the current Financial RRO requires strengthening. If a new RAM is undertaken, such as Operating Reserve or a Physical RRO, then the AEC recommends discontinuing the Financial RRO. In the absence of a new RAM, the AEC does not concur with strengthening its signals or minimising its triggers which will increase these costs.
A18	*[Financial RRO option] What are options to make the RRO simpler, while still advancing some measures of success?* AEC considers the double gate at T-3 and T-1 should be retained, consistent with its original design that it should only be triggered if a prolonged reliability shortfall is observed well in advance and not acted upon. AEC considers it would be simplified if the SA derogation to insert a T-3 trigger at any time were withdrawn. AEC suggests the book build and market liquidity obligation should be removed as adding complexity and little value.
A19	*[Financial RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?* One challenge relates to compliance based on position at T-1. This creates a challenge for retailers uncertain of their customer base ahead of time and in that way limits retail competition. Whilst recognising that the intent is to encourage forward contracting, the AEC urges consideration for allowance of some positions achieved closer to T.

	Distributed demand-side response has a probabilistic characteristic and is naturally difficult to convert to a deterministic measure as required by the Financial RRO. Members report challenges in that regard with respect to the Financial RRO procedures. In order to avoid limiting innovation in this area that the ESB sees as a key part of the transition, the AER should aim to provide a supportive, rather than conservative, approach in managing the inevitable uncertainty. Members also report challenges regarding the accounting for customers' existing long-term contracts with unaffiliated generators: a retailer should be able to count the capacity value of the generator to whom the customer is directly contracted, in addition to the retailer's own contractual position.
A20	*[Physical RRO option] Should it be a triggered mechanism, or be developed as a rolling one?* A Physical RRO introduces a form of capacity market into the NEM. A physical capacity obligation is a very major change for the industry and will introduce an entirely new form of market exchange. These designs typically do not have a triggering mechanism as the capacity mechanism, rather than the energy market, becomes the principal provider of capital return for investors.
A21	*[Physical RRO option] How should the physical certificates be regulated?* The entire scheme should be regulated by AER. The very challenging task of determining an equivalent deterministic capacity value of a resource should also be overseen by AER, acting under technical advice from AEMO and an independent expert working group.
A22	*[Physical RRO option] How would a Physical RRO impact contract market liquidity?* Under a Physical RRO, participants must contract for two products: Physical capacity and energy price financial risk. Whilst they may be bundled into the one OTC, separate markets may also develop. The Physical RRO's liquidity will mostly depend on its parameters, for example how conservative is the determination of firmness.
A23	*[Physical RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?* A key desire by all players is to see consumers more responsive to spot market conditions. A significant concern with respect to a Physical RRO or the strengthening of the Financial RRO is that it may impact on innovative retail activities that seek to achieve this, particularly: • retailers arranging non-firm (probabilistic) DSR; • retailing based on a pass-through of spot prices, in order to trigger a probabilistic DSR; and, • retailing based on firming customers' long-term contracts with unaffiliated generators: the retailer should be able to count the capacity value of the generator alongside their own contractual position.
A23	*{Additional comments only on Physical RRO discussion - No relevant question}* *(a) Stage of development* The Physical RRO is a very major reform to the way energy is commercially transacted in the NEM. Considering the scale of the proposal there is little exploration and assessment of it in the paper. This contrasts with, for example, the very detailed explorations of UCS/SSM in Part B. Key matters need to be explored about, for example: • The implications of different levels of conservatism in interpreting firmness of capacity. • The use of different probabilities of exceedance in customer load.

	• How to take into account intra-regional congestion on the availability of firm capacity. • How to take into account interconnector and MNSPs capacity. • Whether the Physical RRO efficiently exploits the benefits of reserve sharing that is inherent to a power system with multiple independent sources of capacity. • What form of penalty regime in relation to the performance of accredited capacity. The AEC's view is that there has been insufficient exploration, socialisation and quantitative assessment for the industry to fairly land on a commitment for or against. More work needs to occur, and a recommendation should not be reached before the end of calendar 2021. *(b) Decentralised vs Centralised capacity mechanism* The ESB last year ruled out centralised capacity mechanisms and recommended only decentralised versions, such as the Physical RRO, for further investigation. This was seen as a smaller step at the time and more consistent with historical NEM approaches. However, after designing a Physical RRO, it may emerge that the supporting structures for the Physical RRO (such as defining eligibility) are so necessarily centralised that the appearance of decentralisation is superficial, and it may be appropriate to allocate the buying task to AEMO rather than retailers.

Chapter 3 - Essential System Services, Scheduling and Ahead Mechanisms	
A24	*What are stakeholder views on what specific design issues should be considered for an operational system security mechanism (SSM) to support the objectives of providing secure operations through the transition of the power system and to support efficient dispatch outcomes?* *Unit Commitment for Security (UCS)* The AEC supports AEMO having the necessary technical tools to intervene when necessary and to commit ancillary services transactions and, as a last resort, to intervene. This appears to be the objective of the UCS. It's not clear why AEMO would need any new powers or rules to run the UCS, and as such, the AEC supports its unilateral development by AEMO. *SSM* The SSM is the more complex proposal for which the AEC has ongoing reservations. To our understanding there is no very pressing need for this mechanism and the AEC suggests its line of work can be de-prioritised versus missing market. One AEC concern is that the existence of an SSM could be seen as a reason to avoid diligent network planning and the use of long-term Network Support Agreements with generators (see also answers to B1 onwards).
A25	*What additional information should be considered to assess the complementarity and materiality of an operational SSM in the context of a TNSP-led solution in the investment timeframe?* The AEC supports using any information delivered by the real time systems to assist the network planning task. However, such backward-looking information may not be of much value to forward-looking network planning, particularly in a period of rapid transition.
A26	*How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?* In 2020, the ESB recommended the AEMC to develop an operating or ramping reserve for two benefits: 1. a RAM benefit by adding an incremental value to firm capacity; and, 2. an ESS short-term balancing assurance benefit. In 2020 the ESB delegated to the AEMC the task of developing and assessing Operating Reserve purely against the second benefit, which the AEC supported. The AEMC has satisfactorily progressed this with the development of four possible designs. The AEC now accepts it appears unlikely to be worth progressing further within the ESS theme. Its value should now be considered from a purely RAM perspective and within that theme. If purely approached as a RAM, the preferred design may simplify, as it would not require such exacting response characteristics as AEMC were considering.
{Note ESS questions continue at B1}	

Chapter 4 – Integration of Distributed Energy Resources and Demand Side Participation	
A27	*What are stakeholder views on the issues raised on supporting market participation for active DER? Are there other paths that could also be considered for different types of consumers?* Distribution networks do not have the technology for visibility of changing energy flows nor for their active control. Peer to peer (P2P) technologies may more readily enable customers to trade or share excess electricity they generate. Customers will always remain able to utilise active DER through existing market arrangements. Incremental simplifications are useful and should encourage greater competition, but not at the expense of existing participants or total system costs. Identifying causer pays will be critical given the ESB assumes no customer who does not participate can be worse off. The ESB correctly observes that distribution networks do not have the technology for visibility of changing energy flows nor for their active control. Constraining the export limit has been a low-cost way to limit an increasing level of DER export levels that would require network expenditure to accommodate DER.
A28	*Is the unbundling of services delivered by active DER resources (e.g., solar PV, batteries or smart hot water appliances) 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?* Yes, it is worthwhile, but it's to be confirmed whether the market is mature enough to warrant determining new solutions at this time. The existing frameworks are able to deliver outcomes where benefits are present. Encouraging innovation is a worthwhile aim and should ultimately provide benefits to consumers through more competition and improved offerings. The unbundling of DER energy from other services may eventually form one further way of providing services to consumers but at this early stage of market development a rule change to force it into the retail market is unnecessary due to low interest and interim alternatives. The 2016 an AEMC determination not to make a rule on multiple trading relationships (MTR) noted that the benefits in the foreseeable future would accrue to only a small niche of customers, but that the costs of implementation would be borne by the vast majority of customers not able or not interested in the products or services that MTR may facilitate. Informing that determination, KPMG provided a report that considered nine services for their dependence on MTR and their additional value to consumers. At that time, Energy Consumers Australia contended that MTR was essential for two of the nine (both pertinent to this consultation): 1. charging options for electric vehicles; and, 2. the generation aggregation model. The AEMC notes in its final Determination however, that KPMG did not specify any particular model of MTR to enable these services, and that all of the services identified by KPMG could be enabled under current arrangements through a second connection point. The proposed Flexible Trading Arrangement (FTA) 2 seems to contemplate the same MTR models that KPMG did not identify as requiring discrete servicing requirements. The concern raised that a customer would most likely be charged two sets of network tariffs under existing enabled arrangements is better addressed by network tariff reform[1] to address that tariff

	duplication problem than by the expansive technical and technology requirements of proposed Model 2. Right now, the innovative products and services that enable customers to make real time decisions about whether and when to respond to a market for their DER do not have significant consumer uptake. Partly this is because the hardware (batteries or new appliances) is costly when compared to the returns, and partly because the price signals are not there. In the AEC's view, the current draft of the AEMC Access and Pricing preferred rule/s will at least provide the foundations necessary to overcome the latter, and perhaps make the former more attractive. Other services from small DER, such as FCAS, are also still in their nascent stages. AEMO has considered VPP Demonstration results along with regulatory and technical requirements in its 2020 development of interim arrangements for FCAS from DER. Again, this approach is about providing the foundations for these emerging providers as an interim. The ESB Maturity Plan process is to develop opportunities for customers to obtain value for the energy and services they provide progressively, and to the benefit of all customers. The AEC endorses this approach, and given the current level of maturity apparent, believes that a continuing review of how to best enable the unbundling is required. As rollout of multi element meters and the uptake and penetration of storage and more sophisticated inverters along with other innovation in appliances continues we may reach a point where FTA delivers value to all customers. But right now, we should be expanding VPP and other trials to inform how and what unbundling is necessary and what, if any, innovation and entry is being inhibited. [1] In order not to discourage uptake of a second supply point, consideration could be given to spreading that cost across all users in some way, at a much lower cost per customer than model 2. This would be a lower cost and "no regrets" option as we wait for the market to mature enough for better considered future design options.
A29	*What might be implications of a growing fleet of active batteries or electric vehicles? Are other pathways that need to be considered to reflect these needs?* Greater numbers will enable greater utilisation. The Question as to what saturation level is ultimately valuable. Until such time as this occurs, non-economic trials will seek to develop additional value streams to enhance take up. Where these trials identify shortcomings in the frameworks that are material, the Maturity Plan should progress reforms. As the ESB notes, the improving performance and lowering costs of battery and electric vehicle (EV) technologies is likely to drive further growth in both batteries and electric vehicles over the coming years, supporting new choices and potential value streams for customers as they offer new forms of flexibility in their load to the grid. Regarding EVs, the AEC agrees that the future is increasingly electric with more renewable DER and grid scale energy production, and car manufacturers do have EV alternatives for the mass market. In the AEC's view financial incentives will remain a crucial driver to reduce cost differentials in most EV markets for the next few years at least. For example, the ACT continued to outperform other jurisdictions in EV purchasing which correlated to the largest stamp duty and registration discount nationally. We suggest that Government fleets can also stimulate EV uptake by new fleet purchases of EVs. This both normalizes EVs

	and creates a second-hand market for depreciated EVs that would provide an additional avenue for private ownership. Growing the fleet should be the first priority. International experience demonstrates a strong correlation between public charging infrastructure and the uptake of EVs, whereby the availability of fast charging has the most influence on EV adoption. Fast charging also has a greater impact on both electricity supply and distribution, and so policies that encourage EV owners to charge vehicles outside peak demand periods, and to encourage EV charging providers to optimize grid utilisation, should be supported if we are to grow the fleet of EV's. As with solar PV and smart appliances, EV's will be able to provide opportunities for customers to obtain value for the energy and services they provide to the benefit of all customers. Their needs are not that different to other DER. Policy should focus in the first instance on obtaining a critical mass of EV's for DER participation.
A30	*Are there constraints on switching providers with DERs today? Are constraints on switching likely to occur through standards being introduced now or expected, such as IEEE 2030.5?* Constraints exist where a customer offers high cost DER to a service provider as a means of increasing its returns. For example, in VPP trials, sites are often required to remain with the host retailer for the duration in return for a subsidized asset. In this scenario, the constraint is economic, rather than technical. Standards that enable utility management of the end user energy environment, including demand response, load control, and the management of DER etc. do not impede customer switching. This standard is currently being implemented in California (Rule 21) and Hawaii as well as internationally. In and of themselves, standards that enable utility management of the end user energy environment, including demand response, load control, and the management of DER etc. do not impede customer switching. However, in integrating DER, steps need to be taken now to deviate from further consolidating a network-centric framework. Whilst there may be certain services where a distributor led technical solution is more cost effective for the overall system, the AEC holds a strong preference towards markets that compensate customers for the services provided. Valuing demand flexibility and efficiently integrating DER is not simply about technical standards, but the need to act now to get the market institution right. The regulatory framework governing DER integration must, as its first priority, empower consumers with the choice to utilise and optimise their own DER assets. In the NEM, while services remain linked to technologies, switching will be limited. The evolution of offers in the telecommunications industry is an example of this. In the early years of expensive smart phones, providers offered subsidized devices on long term contracts. Today, providers offer devices and contracts separately, greatly increasing the capacity of customers to engage when they wish to. In integrating DER, steps need to be taken now to avoid further consolidating a network-centric framework. The AEC holds a strong preference towards market that compensate customers for the services provided by their DER.

	Switching with DER will become an important feature of the post 2025 environment. Steps should be taken within the Maturity Plan to identify appropriate reforms, both technical and regulatory, that will deliver this longer-term objective.
A31	*What are stakeholder views on approaches outlined? What might be the advantages and disadvantages associated with each?* *Market to develop:* Support. Limits overbuild and allows customers to opt into arrangements that meet their needs. Common protocols will become ubiquitous with maturity. *National standards:* Potentially suitable for very large DER, but limited value for small customers. *Common business process:* Prefer market led solutions – ultimately same outcome. As customer uptake of DER increases, standards must support customers desire to switch providers. The guidelines to IEEE 2030.5 published under the Standards Australia program will need to subsequently be picked up by DNSP's in their connection agreements. A dozen different approaches by NSP's and then another national process would be an undesirable outcome and must be actively managed. Constant changes in technology, industry practices, and communications will all impact innovation. There is consequently a very high degree of uncertainty as to what will eventuate. The AEC does not support an aggressive timetable that requires anticipating and regulating specific business models too early. We should be cautiously building out the infrastructure as we need it. Early market mechanisms should be seen as an adjunct to, and not an immediate replacement of, existing market infrastructure. Finally, the costs of major changes to market operations will initially be borne by all to the benefit of the few, at a time when the market is not yet mature enough to identify an optimal design in any case. By the time we reach 2050 the market mechanism envisaged today may not be fit for purpose. P2P technologies may more readily enable customers to trade or share excess electricity they generate.
A32	*Are there other potential approaches that could be considered?*
A33	*Under what situations could the distribution network operator perform the role of the retailer / aggregator?* Theoretically, there are no scenarios where it is necessary for a DNSP to act as an aggregator or retailer in a competitive market, provided adequate dynamic limits are published and compliance is appropriate. Physical challenges can be managed by the FRMP on instruction from either AEMO or DNSP based on these network needs, and services procured where efficient. Existing DER fleets should be treated as a legacy issue not a blueprint for future market designs. Simply because DNSP's are currently operating DER fleets such as hot water and air conditioning load as part of legacy models (or in the case of the SAPN requiring that network support services are provided without compensation in return for a new connection agreement[1]) does not mean that these services cannot be supplied by the market. Appropriate signals, incentives, and technical limitations can avoid the need for DNSP controlled assets. However, the DSO can and should be incentivised to procure network services from aggregated DER (and other competitive infrastructure such as metering). This procurement model will encourage two positive outcomes:

	1. Services will be procured on an as needed basis, with no unintended long-term outcomes arising from unnecessary network investments; and, 2. Drive further development in demand side markets, increasing take up and enabling many of the other outcomes sought by this options paper. [1] SA Power Networks Distribution Annual Planning Report 2019/20 – 2023/24 , page 28. SAPN proposes to include modification of the connection standard to require new generation to utilise the capability of their inverters to assist negating the impact of their solar generator on the local voltage.
A34	*How might DER assets be managed in a situation where no retailer / aggregator is nominated?*
A35	*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?* The guidelines to IEEE 2030.5 that will be published under the Standards Australia program will need to subsequently be picked up by DNSP's in their connection agreements. A dozen different approaches by NSP's and then another national process on top of that would be an undesirable outcome. Standardised communications will be the key to that portability. This was not achieved in historical DNSP led technology rollouts. As an example, standard communications protocols could include clear monitoring protocols and potentially frameworks for access and controllability under certain scenarios where the DNSP and/ or AEMO considered that a necessary service to procure.
A36	*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?* One of the foundational design principles for the NEM was that the private sector should continue to take on investment risk and in doing so drive investment in new resources. The ESB has indicated its ongoing support for this principle. The WA DER Roadmap relies upon the incorporation of hosting capacity and distributed generation assets into the RAB. This is inconsistent with driving private investment in new resources, and as a government program that will undercut and crowd out new and potentially existing private sector DER projects, we could be informed from this those roles and responsibilities in the NEM are likely to evolve in a way entirely different to those in the WEM. This transfer of grid scale DER generation assets from the private sector to the public sector in WA ultimately sees consumers and/or taxpayers taking on the investor risk.
A37	*What are stakeholder views on the approaches outlined? What are the potential advantages and disadvantages of each?* *Structured procurement (manual)* This approach represents a truncated RIT-D process. In our experience, transaction costs of RIT-D process appear overstated by DNSP's. A truncated approach is a worthy option and may allow for a significantly lower threshold – potentially down to $50K. *Structured procurement digital platform* High upfront costs, lower transactional costs. The AEC considers the market is not yet mature enough to identify an optimal design. A future consideration for the Maturity Plan. *Retailer portfolio level charges* This approach places responsibility of identifying and maximizing the benefits from distribution limitations on participants sophisticated enough to actually play a role in managing them. Approach should not restrict others as local area network

	tariffs still published and P2P trading still allowed. Don't agree that has high implementation costs, given opt in potential. *Real time distribution market* The AEC does not see this is a plausible option in the medium term.
A38	*Are there alternative approaches that could also work to complement existing tariff reform processes that should also be considered? How might these work?* NMI level network pricing does not deliver appropriate incentives to retailers to actively invest in management of customer loads. Increased granularity and locational pricing could be better utilised as an opt in service for a portfolio load, providing incentives for retailers to develop service offers that benefit their individual customers. An opt in approach for retailers would enable those who wish to seek to maximise the benefits available to do so, but not at a direct cost for those who do not. Importantly, many customers will not be interested or able to participate, and should not have reform imposed upon them, provided the costs of non-participation are borne. To this end, confidence in the tariff reform processes from the perspective of the consumer, the retailer and any other third party interest is essential. Engagement by electricity distribution networks with stakeholders on proposals for more cost-reflective tariff structures has to date left stakeholders with concern for, and the task of managing, the potential harms. Both have included the inability of consumers to mitigate such harm, and the retailers, held accountable for the consumer outcomes, have continued to smooth out network cost reflectivity in favour of a value proposition that consumers will find more appealing. Within tariff statements there has also been widely different approaches to estimating and applying long run marginal costs, sharp differences in tariff structures, and inconsistent approaches to allocating sunk costs. There is in our experience broad stakeholder agreement that Tariff Structure Statements require more fit-for-purpose principles and that a better method for agreement on choices of tariff structures is required. Approaches by the AER, that will be responsible for determining the suitable level of export pricing when proposed by any distribution business under the AEMC draft determination, will have a further direct and cumulative impact on confidence in tariff reform. Even the correct application of the network pricing rules can create a broad suite of outcomes. Marrying this flexibility with confidence and consistency is an ongoing concern. We anticipate that the forthcoming AER consultation on the Export Tariff Guideline (required by the AEMC Access and Pricing draft determination and assuming it proceeds unchanged) will be the best forum and mechanism to expand on general tariff reform principles. The ESB could recommend that the consultation is expanded to capture the same.
A39	*Do stakeholders have views on additional steps or information that should be considered in the proposed consumer risk assessment tool?* The iterative risk assessment tool should have frequent check-ins on the costs of additional protections. The tool only considers if protections are necessary, not whether they are efficient, with the latter left for the rule change process to identify. It's preferable for the tool itself to seek to undertake a summary CBA, in particular identifying if alternative approaches would be see a greater economic benefit to consumers.
A40	*Do stakeholders have views on the options outlined to address issues associated with falling minimum demand and increasing access to markets?*

	Access and pricing reforms will encourage better utilisation of DER, and minimise problems. In the meantime, reforms should be: • voluntary; • proportionate; and, • low impact
A41	*What are other options to consider that might deliver better outcomes for consumers?* Networks could be required to develop their tariffs based on consumer need, and in time to enable action to be taken. If backstop is required, networks should be penalised under STPIS or other scheme. The current framework does not incentivise DNSPs to develop tariffs that solve future network problems in a manner that customers will be willing to accept. Placing the responsibility for the outcome on the network will encourage more customer centric tariffs, rather than the economically efficient, yet network centric tariffs we have seen to date.
A42	*Do stakeholders have views on the proposed principles? Are there other principles that should be considered to deliver benefits for consumers?* A question for the Maturity Plan. Why build in commonality within the NER if other processes eventually supersede (e.g., CDR, market led solutions, agreed common protocols).
{Note DER questions continue at B20}	

Chapter 5 – Transmission and Access	
A43	*Does the proposed reform pathway for transmission and access meet the needs of the transition?* The AEC does not support conducting another review of the RIT-T, which has been previously assessed many times. The AEC is particularly concerned with the proposal to incorporate social benefits which are inconsistent with the National Electricity Objective and extremely subjective. The AEC is amenable to streamlining the regulatory assessment of ISP projects where genuine duplication is occurring. This may be the case for large contingent applications. A disputable, individual cost-benefit and assessment of alternatives must still be performed through the regulatory process, and more information is required to ensure the proposed streamlining will retain these features. The AEC does not disagree with any of the discussion in pages 83-93 that postulate the shortcomings of a regional market design. However, it must be recognised that after 23 years the industry's commercial structure is firmly based around it. The question then falls to the extremely difficult judgement of whether the benefits of moving to theoretically superior arrangements exceed the costs of a very large disruption. All AEC members recognise the scale of this disruption and, as a result, disagree with moving quickly, say before the second half of this decade. There are mixed views on whether the cost/benefit suggests the industry should adopt a new model over the longer term. The paper has proposed several medium-term partial options, leading towards a full solution, such as Locational Marginal Pricing/Financial Transmission Rights (LMP/FTR) in about a decade's time. In the AEC's view, if that is to be the long-term solution, then this should be resolved, and a firm date set. For the preceding years the market should not be further disrupted by short-lived reforms. As the AEC has consistently stated through P2025 and the Co-ordination of Generation and Transmission Investment review, if an LMP/FTR regime is to be introduced, it must provide extensive transitional arrangements so as to both achieve the objective of the reform and to avoid a major risk to existing investments. Those transitional arrangements should take into account access levels in existence at the time of making the rule.
A44	*For each medium-term access option presented in Part B:* • *Do you think that the model satisfactorily addresses the access reform objectives set out above?* • *If any, what is your main criticism of the model?* • *What additional detail do you require to understand the option?* *Plain Vanilla Congestion Management Model:* A relatively unambitious reform, intended to provide some benefit with respect to dispatch efficiency, however it is not an access model per se. As it does not grant any long-term access right, the principal criticism of pages 83-93 remains: new generators sharing congestion with incumbents. Thus the key rationale for considering an access reform is not achieved. *Modified Congestion Management Model within new transmission investment:* This seems consistent with the financial REZ access model that the ESB and NSW government have already promoted. Such a model may be beneficial within such a REZ, however that is a decision that can be left to the developers of the specific REZ. *Locational Connection Fee for new connecting generators:*

	This may be worthy of consideration, noting previous attempts to assess a long-run marginal cost (LRMC) of transmission augmentation are very challenging. There would need to be example calculations to appreciate this. *Generator TUOS:* This can be a reasonable simplification of LRMC. It would however be essential to grandfather existing generators: there is no point in providing a locational signal to sunk investments. One of the risks of such an arrangement is that providing an exemption to an apparent tax can be politically challenging, even if it is economically appropriate.
A45	*Which medium term access option is preferable?* See A43
A46	*Are there alternative options that the ESB should consider?* See A43
A47	*Are there potential improvements to the options that the ESB should consider?* See A43
A48	*Would enhanced congestion information help to improve the coordination of transmission and generation investment? If so, what additional information would add value?* AEMO is presently consulting on the range of information provided in their Congestion Information Resource which was created as a recommendation of the 2008 AEMC Congestion Management Review. Suggestions in this regard should emerge there.
A49	*What are stakeholder views on when these arrangements should be implemented by? What should be taken into account when determining implementation timeframes?* See A43

<table>
<tr><td colspan="2">Part B</td></tr>
<tr><td colspan="2">Resource Adequacy Mechanisms</td></tr>
<tr><td colspan="2">No further consultation questions in Part B</td></tr>
<tr><td colspan="2">Essential System Services, Scheduling and Ahead Mechanisms</td></tr>
<tr><td>B1</td><td>What are stakeholder views on the interactions between the proposed investment and operational procurement mechanisms for structured procurement?
• In what other circumstances to the ones listed in the paper would having both mechanisms be complementary to one another? How should they be designed to support this complementarity?
• In what circumstances might having both a long-term and short-term procurement mechanism potentially cause unintended consequences? What should be done in the design to mitigate these risks?
• What are the potential impacts, in either or both mechanisms, for the different segments of industry, for efficient investment in transmission and generation, and efficient operation of the system?

The AEC is supportive of “Network Support Agreements” (NSAs), i.e. non-TNSP assets competitively providing non-energy services in lieu of network equipment. As multi-year agreements, NSAs oblige diligent planning by networks whilst providing non-TNSP assets confidence in their revenue and performance expectations. NSAs can be dispatched by a less sophisticated tool than the SSM, such as the UCS or even manually as occurs currently.

The SSM concept appears to be a form of NSA procured on an hourly “as available” timeframe. There is a danger that it undermines the long-term planning which will lead to an incorrect assumption that such short-term NSAs will be available when needed. It also leads to uncompetitive scenarios.

The AEC prefers that non-network services be procured by long-term NSAs and that TNSPs always take diligent planning action well ahead of time. If, despite good planning, security is unavoidably breached, then the last-resort power of direction will recover security.

At the same time the AEC notes a legitimate concern that ahead planning by TNSPs may lead to a natural preference for conventional monopoly assets. It is the task of the AER to oversee and resist this incentive. The AEC is pleased to note the draft system strength rule has some safeguards in that regard.</td></tr>
<tr><td>B2</td><td>How do stakeholders envisage contracting arrangements will work under the long-term procurement mechanism, and how may this interact with the design of the SSM or vice versa?

As noted above, the AEC is unsure whether the SSM is beneficial and prefers reliance on longer term NSAs. The AEC’s largest concern about the SSM is that it is likely to lead to networks not entering long-term NSAs.</td></tr>
<tr><td>B3</td><td>Do stakeholders agree that the UCS should schedule for an efficient level of the service which has been structurally procured, with the efficient level being with regards to meeting a dispatch cost minimisation objective, as defined by the terms of contract activation and pre-dispatch bids. If so, why? If not, why not?

The AEC considers that the efficient operation of the power system should be achieved through decentralised competition and self-commitment rather than central commitment decisions.
The principal purpose of the UCS should be to minimize the cost of the actual intervention and/or service itself in order to remain within a secure system envelope.</td></tr>
</table>

	If the objective is larger, i.e. lowering total cost of dispatch, there is a concern that the tool will progress towards an effectively centrally-committed energy market, because committing services will also introduce energy. This concern is discussed further in B4.
B4	*Do stakeholders consider the potential for the UCS to centrally-commit contracted resources to be of material concern?* *If so, are the proposals put forward by the ESB sufficient to address this concern?* *If not, what should be done to mitigate this concern?* See answer to B3. The concern could be entirely removed by limiting the objective function of the UCS to minimising the cost of the commitment in order for the dispatch algorithm to have a feasible secure operating space within the technical envelope: i.e. it would only activate to avoid constraint violation. However, the AEC accepts that the existing rules, and the draft system strength rule, anticipate non-energy services being committed to enhance the overall value of trade. The danger is that because some services will also bring energy, if given a total dispatch cost minimization objective, the UCS will commit for energy, undermining the self-committed energy market. A suggestion to retain this objective, but reduce the risk of centrally committing for energy, is to only trigger a UCS run when specific, predefined constraints are observed to bind in predispatch. These constraints would be the ones associated with, say, system strength, and for which NSAs had been specifically engaged to relieve.
B5	*If the UCS commits units ahead of time, how would this interact with the existing wholesale spot and frequency markets that are real-time?* Since market start, NEMMCO/AEMO has been committing NSAs from time to time through manual processes which have primarily focused maintaining security whilst minimising the cost of the use of the NSA. There are resulting impacts on the markets, but these are minor. If the objective function of the commitment decision is limited to the minimisation of the cost of the commitment, then no new issues should emerge. If however, the objective is to improve the total value of trade, then it risks undermining self-committed energy markets: See B4.
B6	*What are stakeholder views on how the UCS schedule should be reflected in pre-dispatch and dispatch (i.e., contracted resources being required to bid into dispatch to be scheduled and/or constraints applied)?* *Are there any possible unintended consequences of these approaches?* Anticipated UCS commitment decisions should be reflected in predispatch, and in dispatch once they are activated. This is analogous to “good faith bidding” by generators and obligations upon TNSPs to reveal their intentions. The predispatch is an iterative process where inputs, both centrally provided and externally provided, are continuously changing for good faith reasons. These iterations permit the market to progressively converge toward optimum dispatch as real time is approached. The central commitment of resources via the UCS or SSM is likely to itself change the plans of resources committed decentrally. An iterating UCS/SSM could be a legitimate part of the optimization process, and the ESB should not propose any gate-closure or other device to inhibit this. Convergence is more likely to occur if

	the process can be quickly iterated. Therefore, run-time for UCS/SSM is critical. The ability to rerun quickly is potentially more important than perfect accuracy.
B7	*Do stakeholders consider the potential interactions between pre-dispatch, dispatch and the UCS to be material? I.e., that participants may change their self-commitment status following the UCS run.* See B6
B8	*What are stakeholders' views on the best way to address the potential decommitment?* See B7: By iterating UCS as quickly as possible alongside predispatch iterations.
B9	*How do stakeholders think that the uncertainty associated with scheduling units ahead of time in the UCS should be managed? Are there any considerations that should be taken into account in addition to those outlined above?* See B7: UCS should iterate as many times as possible and permit AEMO to lock into commitment/decommitment decisions as late as the parameters in the arrangement allow. Preferably the UCS would iterate alongside predispatch, i.e. half hourly. The paper states solution time would take 30-90 minutes. In order to try to keep under 30 minutes, the UCS should look to simplifications rather than fully exploring all commitment possibilities.
B10	*Do stakeholders agree with the ESB's proposal that TNSPs would be responsible for providing AEMO with the required contract information for the system service contracts, where these have been agreed between the TNSP and the relevant resource?* Yes. The AEC understands this is the existing arrangement.
B11	*How do stakeholders envisage the contracts for system services would be designed where these are to be scheduled by the UCS, and what information would be required to be provided to AEMO to support the scheduling mechanism?* AEMO could provide guidance to TNSPs as to what parameters are most readily incorporated into the UCS.
B12	*Do stakeholders consider that all system service contracts (e.g., system strength) should be required to be scheduled through the UCS? I.e., must offer? If so, why? If not, why not?* Whilst preferred to be scheduled through AEMO's UCS tool, there is no need to be mandatory. There may be some NSAs who are technically incompatible, or extremely simple, and may continue to be manually committed as per current arrangements.
B13	*Do stakeholders agree with the transparency measures proposed for the UCS implementation, or suggest other considerations exist that should contribute to transparency with regards to the UCS?* Yes. Transparency and predictability of the UCS process is one of its key advantages compared to AEMO's existing manual commitment decision process.
B14	*How do generators and demand response providers position themselves under current frameworks ahead of periods of high ramping or periods of uncertainty?* Chapter 4 of the AEMC's Directions Paper provided an excellent summary of how this occurs under the current market design: high ramping and uncertainty can be efficiently managed without an explicit mechanism. The AEC agrees with the AEMC's characterisation.
B15	*What challenges are envisaged in a future with higher variability and uncertainty in net demand?*

	The future includes a paradox: • There will be greater variability and uncertainty; but also, • There will be more flexible resources with greater ability to respond quickly. The AEMC's initial assessments suggest the second will grow faster than the first, implying the concerns that led to this research may actually decline in the future. Whilst power systems have always had stochastic characteristics, forecasting supply/demand has an ever wider growing distribution of uncertainty. That must be accepted and managed. It will require evolving forecasting tools away from single deterministic outputs into probabilistic confidence intervals.
B16	*How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?* The four forms of operating reserve straw manned by the AEMC all create intricate and complex interactions and incentives on the energy dispatch itself, and, at worst, could actually undermine the existing incentives to provide operating/ramping reserves. The AEC now supports investigation of the Operating Reserve model purely under the RAM framework. A risk demonstrated by the AEMC work is that complex Operating Reserve models where generators switch between the Reserve and Energy markets can create unintended consequences. However, if engaging an Operating Reserve purely for its RAM benefit, the model may potentially be simplified to something closer to the well-understood Standing Reserve which seems to have less of these risks.
B17	*Who should pay for reserves and why?* Whilst a form of "causer pays" is always attractive for a new service, this would appear to require some kind of locked-in ahead market in order to identify the causers of variation. The AEC does not support an ahead market model. If the Operating Reserve is purchased purely for its RAM benefit, then this is ultimately for the broader benefit of customers.
B18	*How would the fleet described in the case study have positioned itself under current frameworks in a future with higher net demand uncertainty? Would it have provided more ramping reserve?* See answer to B14
B19	*In what circumstances would a reserve service be beneficial for consumers?* Some of the AEMC's strawmen identified that the nature of the reserve service might actually reduce spot price volatility because, when required, the reserves would be invited to the energy market and suppress a price spike. This was described as potentially benefiting customers. However, the AEC sees this as problematic in two ways: 1. The resulting price suppression is a *distortion* to the necessary volatility that results from rapid swings and which encourages decentralised provision of reserves in the current design; and, 2. One of the rationales for the ESB in 2020 to progress Operating Reserve was to "sharpen" price signals at times of stress in order to provide additional RAM assurance. This "benefit" then seems to run counter to the intent.

Integration of Distributed Energy Resources and Demand Side Participation	
B20	*What are stakeholder views on the proposed Maturity Plan approach and priorities identified for the first release?* The AEC is comfortable with the proposed first release of the Maturity Plan. In general, the AEC considers that for future releases, the plan should focus on mature technology and identifying proportionate responses to known problems at the time, rather than seeking to develop future solutions to potential problems. The AEC prefers market led or demand driven reforms, rather than attempting to identify potential solutions to enable particular business models. This will require the Maturity Plan to be iterative, identifying where technological maturity and customer demand are at a point where appropriate reforms can be clearly identified and implemented. This may require the Maturity Plan to have a monitoring function, to identify if there is a demand for the type of service proposed before undertaking supply side reform.
B21	*Do stakeholders have any feedback on the approach for developing the trader-services model pathway?* The AEC support this reform.
B22	*What technical and regulatory barriers, challenges and opportunities may Model 2 present to Traders, end-users and distributors? What challenges would be present for metering services in either model?* There is little evidence that suggests Option 1 would not allow for the services proposed to be offered. Given this, it is unnecessary to build additional costs into the system on the basis of theoretical benefits. The costs are additionally unclear. While Option 1 clearly would increase costs to the user, the user is the party that seeks to benefit from the arrangement. Given the broader principle of the ESB that customers will not be required to participate to benefit from reforms, this seems an appropriate outcome. Option 2 will likely have lower costs to the user, but it is yet to be seen the quantum of any reduction. It may be that Option 2, with more appropriate network tariff reforms as discussed above might deliver the benefits sought with lower risks.
B23	*How might the designs be improved to accommodate and facilitate greater trading of non-energy services from either model?* Option 1 easily enables trading of non-energy services. Option 2 appears to diminish the ability to trade in these services as it will be reliant on the flow of energy in the grid connected meter. For example, if site is consuming 3kW, and generation output is 2kW, will any electricity flow back into the grid? In this instance, the issue at hand is economic arbitrage rather than technical system benefits. Further work needs to be done to better understand how a single connection point might manage this challenge.
B24	*What are the benefits and risks of enabling arbitrage between separate connection points? If there are risks, including for retailer and network tariffs, how should they be mitigated?* There are likely to be consequences both for the customer and the retailer from a third-party managing arbitrage between the grid and the DER. For a participating customer, they should be incentivised to use their own generation where it is efficient to do so. There is a risk that incentives for the customer and the SGA/PMA operator will be misaligned. For example, a customer might pay their retailer a 40c peak tariff, but SGA operator is able to make 30c selling excess consumption to the grid during a high-priced interval. In this instance the customer would be better

	off self-consuming, but SGA loses high value kWh if it switches spare generation to house. Similarly, retailers will be unable to accurately predict customer consumption patterns, which may impact their hedging costs, and have other flow on impacts – increasing the costs to serve. This is particularly the case where the SGA owner will have the sole ability to switch the bidirectional flows from the DER.
B25	*Do stakeholders consider there to be high implementation costs for any of these options? If so, would these costs be borne by all system users or predominantly by the party choosing to enter the flexible arrangement?* Option 1 would likely have higher costs to the party seeking to develop the arrangement, while option 2 would likely have higher system wide costs. Given that, Option 1 is more cost reflective. As noted above, these costs could be mitigated through better leveraging of existing market and regulatory processes. Option 1 is analogous to a homeowner taking out a fixed and variable mortgage on the same property. Both charge an annual fee, however, customers who benefit more than the cost will be incentivised to enter multiple agreements. The AEC considers that use of an FTA should be limited to customers where it is economically beneficial to do so. Option 2, in passing some of its cost onto the system risks artificially inflating demand for FTA to a point that is inefficient.
B26	*Are there other options the ESB could consider on the path to support more flexible trading for end-users?* Option 1 could be enhanced through increased obligations on DNSPs to enable uptake through network tariff reform. For example, multiple NMIs on a single site could be charged a single fixed charge to mitigate the existing barriers.
B27	*Are the stated objectives appropriate? Should additional objectives be considered in the design of a 'scheduled lite' arrangement?* The AEC support Principles 2 and 3. Creating a framework for greater participation without delivering greater participation is inefficient. The challenges of achieving sufficient voluntary participation are discussed further below.
B28	*Are there any additional or alternate principles that should be considered?* The AEC consider that the ESB's principle that no customer should be worse off if they do not participate means benefits, would need to be significant to encourage participation. This approach risks overpaying for participation or achieving no take-up. To be successful, a scheduled lite framework will need to increase incentives/obligations to participate based on impact to system security in time. The AEC considers this means a longer-term pathway towards more mandatory approaches.
B29	*Are there any additional scheduled lite models or design elements that should be considered through this process? If so, what are the purpose, key features and benefits?* The benefits from scheduling are largely delivered when scheduling is widespread and adhered to. These benefits largely fall to the system as a whole rather than the individual, so utilising a minor 'carrot' to encourage participation will likely be unsuccessful. If a more mandatory, yet lighter compliance approach consistent with the intention was implemented, this would likely increase efficiency in dispatch and lower costs overall, however would naturally place a greater onus (i.e., costs) on traders themselves.

	In particular, large point source loads that respond to price have no less impact on the market than an equivalent sized scheduled generating unit. There seems no reason why such loads would not be subject to similar requirements as scheduled generators.
B30	*Are the forecasting requirements proposed for the visibility model appropriate? Are there alternate options for granularity, frequency and use?* This model would only be used by DSR within a mandatory framework. The AEC suggests the only workable "carrot" for its use would be as an alternative to the other more onerous forms of scheduling. This model could be appropriate for DSR that is made up of an aggregation of many distributed responses. It would be appropriate in a mandatory framework where compliance by some aggregators to centralised dispatching arrangements could be demonstrated by them to be impractical. In a mandatory framework, a standard penalty arrangement for non-compliance seems appropriate. When taking compliance action the AER takes into account the practicality of the compliance, the stage of learning that the participant is up to, and its efforts to achieve forward compliance.
B31	*Are the bid requirements appropriate for the dispatchability model?* Again, AEC considers this will only be used in a mandatory framework. The bid requirements seem largely correct. Providers could decide whether they prefer to provide their medium-term information through the Demand side Portal or the MTPASA.
B32	*What are the barriers, if any, to self-forecasting? How far ahead of time would a resource be able to provide meaningful forecasts of their likely behaviour?* These forecasting challenges are equally applicable to a generator of equivalent size, and the impact of the behaviour on the market are also equal. As these challenges have been managed by generators for 23 years, there seems no reason for the on-going inconsistency of expectations between the supply and demand-side.
B33	*How appropriate is the use of threshold accuracy and non-financial penalties for inaccuracy? What are the trade-offs of using this approach?* In a mandatory framework, a standard penalty arrangement for non-compliance seems appropriate. When taking compliance action the AER takes into account the practicality of the compliance, the stage of learning that the participant is up to, and its efforts to achieve forward compliance.
B34	*How appropriate is the proposed approach for the dispatchability model?* *Will the use of the threshold meaningfully reduce barriers to participation?* *What are the trade-offs associated with the use of a threshold?* *How should that threshold be determined (e.g., MW accuracy, or proportion of dispatch targets etc.)?*
B35	*Should an opt-out approach prior to dispatch, like that used in New Zealand, be adopted? Would that meaningfully reduce any barriers to participation?* In the AEC's view, having developed an ability to bid and respond to scheduling, there is no individual saving in temporarily switching off the scheduling. If a resource is in a state that it is not responsive to price, then the bidding becomes trivial – it can simply enter a standing bid. There is a risk of unintended outcomes with opt-out in that it may be used to avoid scheduling at exactly the moment it is most useful.

B36	*How appropriate are the proposed additional participation elements for the visibility and dispatch models?*
B37	*For the dispatchability model, will the use of lighter SCADA arrangements meaningfully reduce barriers to participation? What other types of solutions could be considered?*
B38	*Aside from those listed above, should the ESB consider any other elements of the scheduling framework when designing additional participation requirements for scheduled lite arrangements?* The AECs view is that scheduled lite needs to operate within a mandatory framework. Further, for single point responsive loads that are greater than the mandatory generator scheduling threshold, these should be mandatorily subject to a dispatchability mechanism of a similar nature to that used by generators.
B39	*How appropriate are the proposed incentives for the visibility model, including:* • *avoided FCAS costs* • *reduced operating reserve costs (if introduced)?* *Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?* It is unlikely that these incentives will lead to voluntary adoption of the scheduled-lite framework by any resources. By way of comparison, these incentives already apply to generators who become scheduled, yet none who, due to size or grandfathering, are non-scheduled, have voluntarily elected to become scheduled.
B40	*How appropriate are the proposed incentives for the dispatchability model, including:* • *avoided FCAS costs* • *reduced civil penalties* • *avoided RERT costs* • *avoided RRO costs and the ability to underwrite qualifying contracts (subject to firmness rating)* • *reduced operating reserve costs and ability to bid into operating reserve market (if introduced)?* See AEC response to B39.
B41	*Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?* See AEC response to B39.
B42	*Are there benefits of making a distinction between active (or controllable) and passive (not controllable) behaviours behind a connection point?* If any part of the load is controllable, then the simplest approach for all parties is to treat the entire connection point as controllable. Bidding for the non-controllable element is trivial and can simply be added to the controllable bid.
B43	*How might a market participant (retailer; aggregator) provide information across their portfolio (many connection points)?* The dispatch engine operates nodally, so it requires locational information. Aggregators know the locations of their node, so it should be no more complex for them to bid to the granularity of the Transmission Node Identifier (TNI) than regionally. More data will transact between them and AEMO, but this occurs through a computer process will not actually make the engagement more complex.
Transmission and Access	
No further consultation questions in Part B	