Dr Kerry Schott
Chair, Energy Security Board
By email: info@esb.org.au

9 June 2021

Dear Dr Schott,

Post 2025 Market Design Options Paper

ENGIE Australia & New Zealand (ENGIE) appreciates the opportunity to respond to the Energy Security Board (ESB) in response to the Post 2025 Market Design Options Paper ("the Options Paper").

The ENGIE Group is a global energy operator in the businesses of electricity, natural gas and energy services. In Australia, ENGIE has interests in generation, renewable energy development, and energy services. ENGIE also owns Simply Energy which provides electricity and gas to more than 750,000 retail customer accounts across Victoria, South Australia, New South Wales, Queensland, and Western Australia.

ENGIE supports the ESB's delineation of the various reform options into current reforms, next priorities and longer-term reforms. This provides useful information on the sequencing of reforms.

In general, ENGIE considers that where current reforms require rule changes, these should be progressed pursuant to existing rule change processes, i.e., the Options Paper is not an opportunity for stakeholders to bypass those processes by appealing to the ESB, in particular, to enliven reform proposals that have failed previously, for good reasons, rather progress those reforms through than the Australian Energy Market Commission (AEMC) assisted by any new evidence.

Below, ENGIE provides some high-level feedback on the options raised under each of the four themes of the Options Paper. Appendix 1 contains answers, where relevant, to the specific questions the ESB has asked.

Resource Adequacy and Aging Thermal Generator Retirement

Energy market performs well

ENGIE considers that the issue of resource adequacy is one that is inherent in any electricity market, whatever its high-level design. The NEM's approach of an energy only market (EOM) with relatively high market price cap (MPC), coupled with a dynamic contract market has served it well for many years, providing adequate reliability at efficient cost.

In this context, ENGIE is disappointed that the ESB has not taken up ENGIE's recommendation in our response to last year's Consultation Paper to include changes to the market reliability settings as one of the options for resource adequacy. This option would have the merit of minimal implementation costs and utilises incentives that have worked to date.

RRO options

By contrast the options of a triggerless Retailer Reliability Obligation (RRO) and a Physical RRO are both predicated on the effectiveness of the RRO mechanism, which has yet to be tested. It is unclear to ENGIE why retailers are considered the party best placed to bear the risks of underwriting new investment, when there appears to be limited appetite amongst customers to sign long-term retail agreements.

To the extent that the ESB is minded to amend the RRO to see if it delivers greater resource adequacy than the status quo, then ENGIE understands the value of implementing the Physical RRO if it can be shown that its creation has the effect of supporting marginal dispatchable generation units.

If this is not the case, and the Physical RRO is not intended to support dispatchability, then the value of the Physical RRO seems limited. This is because plant, including renewables, already sell firm contracts to the levels they are comfortable, based on their risk limits, and manage these exposures physically and financially. Thus, assigning a proportion of nameplate ratings to all plant to sell as physical certificates onto top of existing contracts, is contrived and creates an additional complicated mechanism that is likely to simply mimic existing market outcomes.

If, despite this, the ESB feels change is required, and it isn't for the purpose of rewarding specific forms of dispatchability, ENGIE considers the triggerless RRO to be preferable to the physical RRO. The former at least has the merit of utilising the existing contract market, which market participants willingly engage in as a valuable risk management tool, rather than creating a new instrument (the certificates of physical capacity) by regulatory fiat.

In either case the current Market Liquidity Obligation (MLO) would no longer be fit for purpose and should be removed, noting the MLO use in some jurisdictions seems unrelated to the existing RRO.

Interventions weaken the value of any new policy

Any market design would struggle to be robust in the face of extensive government intervention, which has reached chronic levels in the NEM. Accordingly, the value of any new resource adequacy mechanism (RAM) is dependent on its ability to replace government intervention as the primary driver of new investment.

In this light, ENGIE considers that any advice from the ESB to the Energy National Cabinet Reform Committee (ENCRC) with respect to new RAMs, should make clear that a new RAM should only be implemented if governments are prepared to step back from the market and give the RAM a chance to work. If they are not prepared to do so, then a new RAM will only add compliance cost and complexity without achieving anything.

In principle, ENGIE is supportive of the ESB's initiative to draw up principles to guide the design of government schemes aimed at supporting investment in the sector. However, ENGIE wonders whether governments have indicated to the ESB – even privately – that they are seeking such advice.

If not, then it is not clear that there is much prospect of the principles being applied in practice and that it may be better to accept the landscape for investors and decisions on capacity has markedly changed since the commencement of this Post 2025 Review.

ENGIE notes that jurisdictional governments have stated that there are multiple criteria, many unrelated to the energy system (such as job creation) that are driving their decisions to support investment, and it is unlikely that these would all be adequately accounted for in a set of economically robust principles.

Moreover, the Commonwealth, Queensland and Tasmania governments all own large generation businesses, and there is likely to be some ambiguity over whether new investments by these businesses are purely internal commercial decisions or are serving government policy objectives. Which is well within the rights of those shareholders.

Aging thermal plant

With respect to aging thermal generator retirement, ENGIE does not consider that there is a clear problem requiring further reform in this area. Since the introduction of notice of closure retirements, plant closure announcements have provided more time than the regulatory minimum. Roughly speaking, AGL provided five years' notice for Liddell, Energy Australia provided seven years' notice for Yallourn, and Origin Energy has recently indicated a closure schedule for Eraring nine to eleven years out.

To the extent that market investment signals are still effective in the light of chronic government intervention (as discussed above), these would be undermined by arrangements designed to extend operation beyond announced dates of closure. Thus, when dates are confirmed, it would be better to focus on ensuing new resources are available to preserve reliability beyond the plant's closure date then seek to extend plant life or artificially surprise prices.

Mothballing

To the extent the ESB's concern relates to mothballing or seasonal operation, ENGIE notes that these are normal commercial practices which are carried out when price signals indicate a plant or unit is temporarily surplus to requirements. Such practices are more flexible than plant closure as there is scope to bring the plant or unit back into service when circumstances change. Thus, the ESB should avoid discouraging such practices through excessive requirements on plant owners and be wary that it may actually force plant into early retirement if attempts are made to force uncommercial plant to continue to run.

In any case, plant operators are already required to indicate forward availability via MT-PASA reporting, and this should be broadly adequate in terms of information requirements. The adequacy of MT-PASA was considered as recently as 2019-20, in rule change process ERC0270, and the rules were updated in 2020, including a requirement for participants to submit inputs that represent their current intentions and best estimates.

As the unfortunate events at Callide C on 25 May illustrate, no amount of legislation or regulation can mitigate completely unforeseen outages in any case. So, it may be preferable to focus on confirming that the system and market are resilient to unexpected loss of capacity. To this end, an operating reserve may be a useful tool for supporting reliability, noting that the ESB is now primarily considering such a reserve as a system security tool.

Essential System Services, Scheduling and Ahead Mechanisms

ENGIE notes that the AEMC is in the process of assessing a number of rule change proposals that collectively cover the areas the ESB has identified as initial reforms. In this context, there is some ambiguity as to how stakeholder feedback to the ESB on areas such as scheduling mechanisms will be factored into the relevant rule change processes.

ENGIE is supportive of a basic Unit Commitment Mechanism to facilitate scheduling of providers of essential system services such as inertia and system strength. It is less clear that a System Services Mechanism (SSM) for short-term procurement is required at this stage, and how it would interact with long-term procurement processes such as network support agreements (NSAs). This is especially the case when TNSPs appear likely to have or retain responsibility for long-term procurement, while it appears that AEMO would operate the proposed SSM.

ENGIE considers the ESB (or AEMC via the rule change processes) should further consider how to optimise procurement of system services across different timeframes when different parties will have responsibility for those different timeframes. Further, those parties are subject to different cost recovery processes; while AEMO can simply recover costs through market charges, TNSPs are subject to revenue regulation by the AER. Nonetheless, ENGIE acknowledges that there is value in considering whether there are efficient tools to allow non-contracted resources to offer and be remunerated for system services in short-term timeframes, especially if this contributes to a more optimal use of Directions for system security requirements.

ENGIE also remains of the view that there is no case for development of a formal ahead market at this stage, and that this is borne out by ongoing lack of broader support from stakeholders.

The Integration of Distributed Energy Resources and Demand Side Participation

ENGIE notes that this theme differs from the others in that the choices, attitudes and behaviour of end users are especially relevant to the reform pathway set out by the ESB. Accordingly, ENGIE supports the ESB taking a customer-oriented approach to the issues raised under this theme. The Options Paper lists several rule changes and other reform processes under way. What the ESB can usefully to do in this space is:

1) Develop principles around customer rights and responsibilities that will inform current and future individual reform processes.
2) Take a balanced perspective on ways to encourage innovation in service offerings while providing targeted protection for customers where needed.
3) Explore how incentives for service providers to deliver local and system-level services back to the grid are sharpened or muted by existing regulatory arrangements.
4) Outline a high-level long-term vision, potentially building on the analysis to date on two-sided markets to help minimise the risk of policy “dead ends” where interim reforms will need to be reversed as they are not compatible with the long-term vision.

Each of these areas is explored further below.

Customer rights and responsibilities

The controversy surrounding issues such as the AEMC’s draft decision to allow DNSPs to charge export network tariffs, and the ability for AEMO to require South Australian rooftop PV to be remotely switched off is an illustration that there is not yet consensus on what customer rights look like in a world of greater DER. Some key questions are:

- Do energy consumer rights extend to energy production activity (e.g., export of rooftop PV) or does this activity require a different approach, that still needs to be fair to both exporting and non-exporting consumers?
- What rights do/should energy consumers have with respect to new appliances that draw high levels of power from the network (e.g., electric vehicle chargers)? If they have a right to connect, how should any upstream network costs be allocated?
- Do customers fully "own" their own load, e.g., do they have the right to choose whether other parties can exercise control of that load and which party they award the right to?
- Are there responsibilities that go along with these rights, e.g., to what extent should consumers (or their agents) be expected to provide information about key appliances and DER to their retailer, local DNSP or AEMO, so that these parties can effectively manage the resultant impacts on system operation and costs to serve?

ENGIE is not seeking to provide answers to each of these as the appropriate outcomes may depend on community sentiment as well as conventional economic logic. We also recognise that where the answers lead to different arrangements than are currently in place, there may need to be a transition plan to achieve the final goals. Interim arrangements, such as remote shut-off of PV export may be more palatable if there is a clear signal as to how we can move forward to enduring arrangements.

Innovation and regulation

The ESB correctly recognises that innovation by service providers will be essential to finding ways to engage customers with the market and to develop effective demand and DER management solutions. Of course, policymakers and governments will not let innovation come at the expense of appropriate customer protections; however, excessive regulation and heavy non-compliance penalties that are not commensurate with the level of harm caused will continue to stifle innovation.

The evolution of the market will require an evolution of regulation, whereas the Options Paper appears to contemplate new layers of regulation building on what there is today. This is not feasible. The proposed Consumer Risk Assessment Tool asks the question "Are treatments required *in addition to* the existing consumer protection framework?" (emphasis added) implying that risk will only be additive and allowing no scope for a downgrade of risk and subsequent regulation. It's not clear what role there will be in practice for service providers to manage customer risk through voluntary codes for example.

Managing network tariff risks

The Options Paper recognises that network tariff signals could play a valuable role in catalysing new forms of demand and DER management but notes the uneven and slow pace of tariff reform. In principle retailers are well-placed to manage network tariff risks, given that risk management is a core function for them. However, in the case of existing risks, primarily wholesale price risks (and to a lesser extent environmental certificate cost risks) there are a range of risk management tools available. It's not clear that retailers currently have access to equivalent network tariff risk management tools, and this area should be explored further before seeking to accelerate tariff reform.

Notably, even getting access to cost-reflective tariffs has a cost to retailers as they have to upgrade the meter to a digital meter to enable the tariff switch. The ESB notes that the limited rollout of digital meters is holding back tariff reform, and examining ways to address this, including potential cost-sharing models, is a worthwhile initiative.

In the long run it's possible to envisage a system where customers are settled, based on their individual load profile for both wholesale and network costs and the retailer manages its aggregate portfolio through various means. Typically, consumers need not be directly exposed to the underlying varying wholesale and network costs, unless they explicitly choose to be. The latter model is already emerging at both commercial and household customer level and will naturally provide market access to aggregators.

In this light, ENGIE questions the need for the "trader services" model proposed by the ESB, which appears very similar to the previously rejected Multiple Trading Relationships model.

High-level vision

Finally, ENGIE sees value in the ESB developing with stakeholders a high-level vision for the long-term future of the market, without over-specifying outcomes. This could then serve as a guide to the development of interim reforms, which could be tested for whether they contribute to and are compatible with the long-term vision or not. If not, they may still be required as a transitory measure, but at least stakeholders can be clear that such reforms will need to sunset. For example, if a two-sided market is considered part of this future vision, then the upcoming wholesale demand response mechanism will need to be dismantled in due course. Businesses seeking to provide DRM services should be aware that they will need to evolve their business model accordingly.

Transmission and Access

Locational signals

ENGIE has long been supportive, in principle, of attempts to improve the transmission access framework. This will always be a highly challenging area: many incumbent generators do not see value in being exposed to locational signals given they cannot change their location; whereas some new entrants feel they are disadvantaged relative to incumbents if they are exposed to additional costs or risks compared to what the incumbents faced; many investors who do not intend to operate assets long-term have little interest in costs that relate to long-term congestion management frameworks; and TNSPs appear wedded to the regulated recovery of costs as opposed to a different risk-reward balance.

Despite these challenges, the AEMC has made progress in recent years through its Co-ordination of generation and transmission investment (COGATI) review. This has resulted in a firm proposal for Locational Marginal Pricing (LMP) as the key to access reform. As the ESB notes, this is a conventional element in other wholesale electricity markets around the world, although there are sure to be implementation challenges associated with introducing it into the NEM. For this reason and in the light of the uncertainties regarding interaction with other market reforms that may arise out of the Post-2025 market design process, the AEMC and ESB have signalled a delay in implementation until after the conclusion of this review.

This cautious approach appears sensible; however, it is undermined by the proposal in the Options paper to introduce one or more "medium term" reforms as an interim stage before implementation of LMP. Noting those options have the feel of reforms that would inevitably displace the will to implement longer term reform and may have unintended consequences.

Notably, each of the proposed options has been considered in the past by AEMC transmission reform processes and failed to be selected as the best option for the NEM. Accordingly, there appears little to no value in temporarily introducing reforms that have already been assessed as sub-optimal. With the potential effect of sub-optimal reforms on investment being quite negative.

Given the protracted implementation timeframes that transmission access reforms have faced to date in the NEM, the chances of any of these being in place by 2025 appears limited. It may make more sense to accelerate the *development* of the detailed LMP approach even if the implementation does not immediately follow. This will allow generation proponents to better understand the impacts LMP would have on their potential investment and provide a form of signal to avoid locating in areas that are or are likely to become congested. It may also provide a signal of the value of co-locating storage with renewable investment as a congestion management tool.

To the extent the ESB does proceed further with any of these options, it should carefully consider the likely interaction with government intervention schemes, which may well mute any economic signal provided by that option. For example, the connection fee option, being an up-front cost, will likely be cast by generation proponents as a barrier of the sort that government schemes can help overcome by subsidising. In Queensland for example, financial close for the Kidston pumped hydro project appears to have been assisted by the Queensland government's decision to underwrite the transmission line required to connect it into the NEM.

Transmission planning

Given the ESB's enthusiasm for prosecuting transmission reform, it is curious that only options aimed at improving generator locational decisions are on the table. Especially when generation locational decisions are primarily driven by the location of resources, not artificial constructs like REZs.

The huge wave of transmission investment triggered by the Integrated System Plan (ISP) has highlighted the limitations of the current model for deciding what transmission investment gets built, who builds it, and how it is paid for. Each of these is sub-optimal in its own way, manifesting in:

- A range of concerns around the estimation of both costs and benefits of the RIT-T process.
- An underlying assumption that the right to build new transmission rests only with the regional transmission network service provider (TNSP) - except in Victoria.
- Concerns expressed by the TNSPs regarding their ability to finance ISP investments under what is intended to be a benign regulatory framework for network investments.
- Concerns about allocation of interconnector costs between customers of the relevant regions (noting that the ESB has presented separate advice on this issue to Ministers).
- Concerns amongst customers that they are bearing all the risk of stranded or under-utilised investment, while the proponent bears none. Allocating some of the costs (and risk) to generators under a generator TUoS model does not in itself address this issue.

ENGIE recognises the challenges inherent in these issues, but it is disappointing that the ESB has not used the post 2025 market design process as an opportunity to thoroughly analyse them and fully consider relevant reforms. While the Options Paper indicates that the AEMC intends to commence a broader review that may seek to address these issues, this has yet to begin, meaning two years or more have potentially been lost compared to analysing these issues under the aegis of the Post 2025 market design process.

Further detail on each of the above themes can be found in Appendix 1 below. Should you have any queries in relation to this submission please do not hesitate to contact me on, telephone, (03) 9617 8415.

Yours sincerely,

Jamie Lowe
Head of Regulation,
Compliance and Sustainability

Appendix 1: Detailed response to Options paper questions

#	Questions	ENGIE response
Part A		
Chapter 2 - Resource Adequacy Mechanisms		
1	What types of information provision regarding jurisdictional investment schemes would benefit participants the most?	Transparency of process is important: e.g., what amount of which service is being sought by when. Clear and transparent selection criteria, including weightings of criteria help assure stakeholders of due process. A robust rationale of the scheme design choices. Electricity consumers (or taxpayers) should have the opportunity to understand what risks they are being exposed to and why.
2	Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?	Aligning incentives with wholesale market signals, including ancillary services. Underwriting as a safety net may not work in practice – if government terms are attractive, then they effectively become the first resort rather than last. If the RRO is to continue, then government supported investments must participate, or their capacity be subtracted from the amount that retailers must procure.
3	Are there financial principles missing, or that have been included but shouldn't be?	n/a
4	What are some of the market-based signal challenges, if any, with mothballing/seasonal shutdown?	The case has not been made that there are serious information deficiencies entails in current reporting arrangements for mothballing/seasonal shutdown.
5	What additional costs or process burden may the disclosure of such information place on stakeholders?	It depends how disclosure rules are applied. If more information is necessary, the starting point should be to integrate into existing AEMO reporting processes, such as MT- PASA. Accordingly, ENGIE recommends that if the ESB considers something is required to address this issue, it should focus on Option 1 as set out in Part B of the Options Paper.
6	What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?	It is hard to respond to this question without a clear explanation of what disclosures are required and by when.
7	Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?	It could do, depending how it is applied. The idea that a unit must run or be available to run unless the regulator says it's allowed not to is highly concerning.
8	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?	ENGIE does not agree with this proposal. If it is, then ESB should consider how it could be applied on a technology neutral basis, without making all generators incur onerous compliance costs.
9	What suggestion do stakeholders have for defining mothballing?	Mothballing is unlikely to be amenable to an exact definition. To take a contemporary example, if Callide unit C4 does not return to service by the date expected if repairs were expedited, does that constitute "mothballing" by the owners? How would we be able to tell? To the extent a working definition is required, the definition of

		“dry storage” in the Template for Generator Compliance programs should suffice.
10	How can governments, market bodies and market participants better work together to be prepared for exits?	As noted in the main part of the submission, recent closure announcements appear to provide well more than minimum notice requirements, so there is little to suggest that more is specifically required from an energy system perspective. The implications for the local community are important but presumably out of scope for the ESB.
11	Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?	In general, ENGIE’s preference is that governments do not intervene in market processes. If the contract relates to the provision of security services *and* is considered the lowest cost way to obtain the required services, then AEMO is the obvious counterparty (or the local TNSP, if it is a service they have responsibility for procuring).
12	Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?	Yes
13	Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?	In general, although there is concern with the principle that market participants bear risk for wholesale reliability gaps. In normal market situations this may well be appropriate, but the level of government intervention is such that poor decisions by governments may be the driver of reliability gaps rather than any deficiency in market participant behaviour.
14	Are there any obvious priorities given current and plausible likely future market scenarios?	N/a
15	What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?	ENGIE is not aware that a problem has been established with respect to contractual compliance. Accordingly, we do not see the purpose of this question. Rather it indicates and underlying issue: the RRO has yet to be properly tested, and yet the ESB is already considering reforms to it, for which it can have no real basis. While a modified RRO is preferable to ad hoc government intervention, it is hardly optimal, and there is no guarantee we won’t end up with both.
16	Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?	This is also an unhelpful question. It implies that policymakers may switch between RRO designs depending on their assessment of “market conditions”. This would undermine the purpose of the scheme. Fundamentally, either an RRO (whether current design, triggerless or physical) either incentivises the necessary capacity to be delivered or it doesn’t.
17	*[Financial RRO option]* How could you strengthen the signal? Could minimizing the triggers do this? What are the unforeseen consequences or implications with this?	As we have yet to see whether the current design is successful at delivering the requisite capacity (and if it isn’t we will never really know whether that was due to a design flaw or it was undermined by government intervention), this question is premature.
18	*[Financial RRO option]* What are options to make the RRO simpler, while still advancing some measures of success?	Given ENGIE’s comments above, it may be appropriate to wait until the first compliance cycle is complete before further reform. However, removing the market liquidity obligation (MLO) would ease compliance and complexity for affected participants

19	*[Financial RRO option]* What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?	There is a fundamental tension between any retailer liability scheme for capacity and the desire expressed in chapter 4 for increased market access for aggregators. Retailer innovations such as wholesale price pass-through tariffs appear incompatible with an RRO, but they are also the least cost way for aggregators to access the market.
20	*[Physical RRO option]* Should it be a triggered mechanism, or be developed as a rolling one?	Given the purchase of certificates will be a new activity for liable entities (unlike the existing RRO, which is at least based on existing contracting arrangements), a triggered mechanism is preferable.
21	*[Physical RRO option]* How should the physical certificates be regulated?	Some form of compliance check of physical availability is required to ensure the integrity of such a scheme. ENGIE notes that the original requirements for demand response in the Western Australian capacity mechanism were so loose that loads could participate and be paid without any expectation of ever being called on. Careful consideration of how availability is defined (how often, at what notice, for how long, etc.) will be required to balance the demand of technology neutrality against the requirement to deliver meaningful capacity.
22	*[Physical RRO option]* How would a physical RRO impact contract market liquidity?	The physical certificates will be traded in parallel to the contract market, so in principle it may not directly affect contract market liquidity, and may mimic it with negligible benefits if these certificates are not made a smaller subset of available contracts.
23	*[Physical RRO option]* What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?	ENGIE notes that small retailers may benefit from exemption. While it may be challenging for small retailers to effectively participate in a physical RRO scheme, if the certificates result in material cost to liable entities, this will create an unwarranted advantage to small retailers. Further, all retailers will be impacted if retail price regulation fails to take proper account of the costs of scheme participation.
Chapter 3 - Essential System Services, Scheduling and Ahead Mechanisms		
24	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?	ENGIE remains unclear on the need for an SSM, or why the ESB needs to develop such a mechanism in parallel with the AEMC system security rule change processes, in particular the Hydro Tasmania proposal (ERC0290). If the ESB proceeds with the design of an SSM, a key design feature would be to incentivise efficient procurement of system security services over the relevant time frame as well as co-optimisation with the TNSP procurement activities in the investment time frame (NSAs).
25	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?	Complementarity between an SSM and NSAs would likely be best achieved if they were procured by the same party. There are pros and cons to this party being AEMO or the TNSP. These include effective incentives, issues with a dual role as procured/provider, and effective information flows in the necessary timeframes.
26	How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?	More clarity is needed on the purpose of such a reserve, or to put it differently, the operational metric it is seeking to achieve or optimise.
Chapter 4 – Integration of Distributed Energy Resources and Demand Side Participation		

27	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?	See the discussion on this chapter in the main part of our submission
28	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?	ENGIE notes the existence (and growth) of pass-through retail tariff offerings to both business and household customers. These facilitate participation by service providers, such as aggregators, who don't want to become full retailers at much lower cost and compliance burden than the proposed trading services model.
29	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?	Understanding their aggregate impact, what incentives their users/operators are facing, and considering how to address stresses that e.g., fast chargers may place on the networks are all important.
30	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?	N/a
31	What are stakeholder views on approaches outlined? What might be the advantages and disadvantages associated with each?	National level cybersecurity standards appear appropriate and will minimise costs for service providers operating in multiple jurisdictions. Common switching processes appear likely to require onerous levels of intervention in the market. Some common processes, e.g., for registration may be worthwhile and have low compliance cost, but the market should be able to signal the cases when this has value.
32	Are there other potential approaches that could be considered?	N/a
33	Under what situations could the distribution network operator perform the role of the retailer / aggregator?	The question is poorly phrased. If ESB is going to "unbundle" roles, then let's consider all the roles and all the parties that could provide them, as well as the best way to remunerate them.
34	How might DER assets be managed in a situation where no retailer / aggregator is nominated?	If this is potentially a material problem, then the DER installer could be required to nominate an initial party.
35	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?	Limits need to be transparent so the customer can be informed early in the process (as in some situations it may undermine the economic or use case for the DER) and the customer understands who is setting the limit and why.
36	Noting the differences in market arrangements between the WEM and the NEM, are thereaspects of the WA DER Roadmap that could usefully inform how certain roles and responsibilities might evolve in the NEM?	ENGIE has not considered the WA DER roadmap in detail. Undoubtedly it is worth considering in the context of the different market arrangements, given it is seeking to address a very similar set of issues.
37	What are stakeholder views on the approaches outlined? What are the potential advantages and disadvantages of each?	Further information would be useful to understand the trade-offs and complementarities. For example, it is not clear to ENGIE why the retailer portfolio option would have high implementation costs. A hybrid of retailer portfolio tariffs with appropriate peak demand

		signalling but retaining some postage stamp characteristics with a structured procurement option to address granular constraints could be an efficient way to achieve a range of outcomes. However, further development of each of these approaches would be necessary to better identify the advantages and disadvantages.
38	Are there alternative approaches that could also work to complement existing tariff reform processes that should also be considered? How might this work?	n/a
39	Do stakeholders have views on additional steps or information that should be considered in the proposed consumer risk assessment tool?	n/a
40	Do stakeholders have views on the options outlined to address issues associated with falling minimum demand and increasing access to markets?	In principle, the market should be well placed to solve the problem of minimum demand, since it is largely coincident with very low or negative wholesale prices. Accordingly, it should be possible to incentivise demand-shifting and voluntary curtailment of DER output. The question is whether market participants have an adequate range of tools available to them, and the extent to which existing regulations inhibit the development of solutions. These issues should be thoroughly explored before seeking to introduce out-of-market solutions. The Emergency Backstop allows time to carry out this exploration, noting that it is an undesirable tool for the longer term.
41	What are other options to consider that might deliver better outcomes for consumers?	N/a
42	Do stakeholders have views on the proposed principles? Are there other principles that should be considered to deliver benefits for consumers?	In the first principle, "retailer" should be explicitly included, given that the Options Paper elsewhere distinguishes retailers from aggregators.
Chapter 5 – Transmission and Access		
43	Does the proposed reform pathway for transmission and access meet the needs of the transition?	ENGIE's view, as set out in the main part of our submission above is that the medium-term access options are not warranted, and the question is over the pace of development of the enduring LMP regime and whether that can be progressed well ahead of implementation to give market participants some understanding of the risks their plant will face under it. Given this, we have no further comment on the specific questions raised in this section.
44	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?	
45	Which medium term access option is preferable?	
46	Are there alternative options that the ESB	Yes, the status quo whereby the MLF provides a locational signal

	should consider?	already.
47	Are there potential improvements to the options that the ESB should consider?	
48	Would enhanced congestion information help to improve the coordination of transmission and generation investment? If so, what additional information would add value?	
49	What are stakeholder views on when these arrangements should be implemented by? What should be taken into account when determining implementation timeframes?	Existing permitted sites under development should be excluded.
Part B		
Resource Adequacy Mechanisms		
No further consultation questions in Part B		
Essential System Services, Scheduling and Ahead Mechanisms		
1	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?	If TSNPs are to procure long-term (investment timeframe) system security services efficiently, then they should be subject to some cost incentive. The existence of a short-term mechanism as a back-up could incentivise under-procurement of long-term options if the TSNPs don't face the cost of the short-term mechanism (i.e., AEMO runs it). So, there would need to be some separate check that the TNSP had procured an adequate level of services, given the state of knowledge of the system at the time. As the paper notes, circumstances and conditions may change, however, AEMO can use directions (sparingly) as a last resort.
2	How do stakeholders envisage contracting arrangements will work under the long-term procurement mechanism, and how may this interact with the design of the SSM or vice versa?	Service providers should be able to compete on a level playing field. Remuneration should take the same form (e.g., an NSA for a set period of time) whether an external party provides the service or the TNSP seeks to build an asset on its own network.
3	Do stakeholders agree that the UCS should schedule for an efficient level of the service which has been structurally procured, with the efficient level being with regards to meeting a dispatch cost minimization objective, as defined by the terms of contract activation and pre-dispatch bids. If so, why? If not, why not?	AEMO should seek to run the power system efficiently including cost trade-offs between different services. This should not however devolve into central commitment of the energy market as a cost minimisation tool. Self-commitment remains an important feature of the NEM.

4	Do stakeholders consider the potential for the UCS to centrally-commit contracted resources to be of material concern? If so, are the proposals put forward by the ESB sufficient to address thisconcern? If not, what should be done to mitigate this concern?	See answer above
5	If the UCS commits units ahead of time, how would this interact with the existing wholesale spot and frequency markets that are real-time?	Providing the commitment mechanism does not undermine the functioning of the real-time markets and appropriate information is provided to market participants about the impact of the commitment on the quantity required in the real-time market then there should not be a problem.
6	What are stakeholder views on how the UCS schedule should be reflected in pre-dispatch and dispatch (i.e., contracted resources being required to bid into dispatch to be scheduled and/or constraints applied)? Are there any possible unintended consequences of these approaches?	The proposal appears reasonable.
7	Do stakeholders consider the potential interactions between pre-dispatch, dispatch and the UCS to be material? I.e., that participants may change their self-commitment status following the UCS run.	It's in the nature of self-commitment that participants have the right to change their bids. The "bidding in good faith" rules should allay any concerns regarding these interactions.
8	What are stakeholders' views on the best way to address the potential decommitment?	The UCS may need to be iterated alongside predispatch.
9	How do stakeholders think that the uncertainty associated with scheduling units ahead of time in the UCS should be managed? Are there any considerations that should be taken into account in addition to those outlined above?	In the beginning UCS is unlikely to have that many contracts to manage and so will be amenable to regular iteration. This situation can be monitored and if iteration of UCS becomes unwieldy then additional measures can be considered.
10	Do stakeholders agree with the ESB's proposal that TNSPs would be responsible for providing AEMO with the required contract information for the system service contracts, where these have been agreed between the TNSP and the relevant resource?	yes
11	How do stakeholders envisage the contracts for system services would be designed where these are to be scheduled by the UCS, and what information would be required to be provided to AEMO to support the scheduling mechanism?	Either this can be readily resolved by communication between AEMO and TNSPs or TNSPs are the wrong party to be procuring long-term supply

12	Do stakeholders consider that all system service contracts (e.g., system strength) should be required to be scheduled through the UCS? I.e., must offer? If so, why? If not, why not?	This requirement does not appear necessary given ENGIE understands some manual scheduling already takes place. To the extent there is clear value in scheduling through the UCS, this can be reflected in contract terms.
13	Do stakeholders agree with the transparency measures proposed for the UCS implementation, or suggest other considerations exist that should contribute to transparency with regards to the UCS?	Yes, transparency of processes is generally welcome.
14	How do generators and demand response providers position themselves under current frameworks ahead of periods of high ramping or periods of uncertainty?	They position themselves for the opportunity of potential future higher prices, to the extent their plant/DR has the flexibility to respond. In this way resource flexibility is highly valued in the market. This is expected to increase with the start of five-minute settlement later in the year.
15	What challenges are envisaged in a future with higher variability and uncertainty in net demand?	Higher levels of flexible and fast-acting supply are likely to be required. Question is whether there will be appropriate incentives/investment signals in place given chronic levels of intervention in market.
16	How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?	It will depend on the design of the reserve service. However, the ESB should work on the principle that generators and demand response providers are profit maximisers who will look to co-optimise outcomes across different markets.
17	Who should pay for reserves and why?	Consumers would appear to be the prime beneficiaries of reserves. To the extent other participants contribute to the need for such reserves, then a causer pays model is economically attractive. But implementation of such a model can be highly challenging is illustrated by the debate over causer pays design for FCAS.
18	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 Q16 above.
19	In what circumstances would a reserve service be beneficial for consumers?	Where it delivers incremental reliability at a cost below the value customers place on that reliability (VCR).
Integration of Distributed Energy Resources and Demand Side Participation		
20	What are stakeholder views on the proposed maturity plan approach and priorities identified for the first release?	It appears to be a reasonably pragmatic way forward. As the ESB notes, it will be important to re-evaluate the priorities for future releases.
21	Do stakeholders have any feedback on the approach for developing the trader-services model pathway?	The trader-services model appears similar to the discarded multiple trading relationships proposal. The ESB should consider the lessons from that reform process.
22	What technical and regulatory barriers, challenges and opportunities may Model 2 present to Traders, end-users and distributors? What challenges would be present for metering services in either	The impact on retailers should also be considered here.

	model?	
23	How might the designs be improved to accommodate and facilitate greater trading of non-energy services from either model?	This is a worthwhile end goal, however, if the approach is pursued, it may make sense to consider this further for a future iteration of reform, since such services are rarely if at all traded under the existing single retailer model.
24	What are the benefits and risks of enabling arbitrage between separate connection points? If there are risks, including for retailer and network tariffs, how should they be mitigated?	Arbitrage between different connection points is surely undesirable if it results in greater revenue for either the customer or the service provider without any increase in value provided to the system. The question is how material the opportunity would be.
25	Do stakeholders consider there to be high implementation costs for any of these options? If so, would these costs be borne by all system users or predominantly by the party choosing to enter the flexible arrangement?	Both options entail costs, but it would be preferable for costs to largely be borne by the beneficiary – i.e., the party who wishes to enter into the flexible arrangement.
26	Are there other options the ESB could consider on the path to support more flexible trading for end-users?	The ESB could consider ways that a customer with multiple NMIs (i.e., under option 1) could be charged for use of the network based on the aggregate demand profile of the NMIs. While there is a separate issue as to how to split the network charge across the NMIs, this is unlikely to be an insuperable issue.
27	Are the stated objectives appropriate? Should additional objectives be considered in the design of a 'scheduled lite' arrangement?	Yes
28	Are there any additional or alternate principles that should be considered?	n/a
29	Are there any additional scheduled lite models or design elements that should be considered through this process? If so, what are the purpose, key features and benefits?	It is questionable whether a voluntary arrangement will deliver much participation if the incentives are commensurate with the system benefits, noting that there are also risks to participation. However, if a voluntary model can be achieved with low implementation costs, this issue can be tested to better understand how much value it can deliver.
30	Are the forecasting requirements proposed for the visibility model appropriate? Are there alternate options for granularity, frequency and use?	n/a
31	Are the bid requirements appropriate for the dispatchability model?	n/a
32	What are the barriers, if any, to self-forecasting? How far ahead of time would a resource be able to provide meaningful forecasts of their likely behaviour?	An obvious approach for variable resources would be to allow opt-in to AEMO's forecasting tools, potentially on a user pays basis.
33	How appropriate is the use of threshold accuracy and non-financial penalties for inaccuracy? What are the trade-offs of using this approach?	There must be some meaningful penalty for non-compliance otherwise there is unlikely to be any system value achieved.
34	How appropriate is the proposed approach for the dispatchability model? Will the use of	If full conformance is not required, then some threshold must be set to make the model meaningful. If a generous threshold is set,

	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.)?	there should be a clear signal that policymakers will look to tighten it over time as resources and their aggregators improve their tools for achieving conformance.
35	Should an opt-out approach prior to dispatch, like that used in New Zealand, be adopted? Would that meaningfully reduce any barriers to participation?	This approach seems likely to be counterproductive. Resources can signal they'd prefer not to be dispatched by bidding at the price cap. If the price cap is reached, it's a sign the resource is really needed.
36	How appropriate are the proposed additional participation elements for the visibility and dispatch models?	n/a
37	For the dispatchability model, will the use of lighter SCADA arrangements meaningfully reduce barriers to participation? What other types of solutions could be considered?	Up to a point, lowering costs always helps. But the telemetry must meet the needs of the system operator.
38	Aside from those listed above, should the ESB consider any other elements of the scheduling framework when designing additional participation requirements for scheduled lite arrangements?	n/a
39	How appropriate are the proposed incentives for the visibility model, including: avoided FCAS costs reduced operating reserve costs (if introduced)? Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?	Incentives should be aligned with actual cost reductions obtained by AEMO due to participation in "scheduled lite".
40	How appropriate are the proposed incentives for the dispatchability model, including: avoided FCAS costs; reduced civil penalties; avoided RERT costs avoided RRO costs and the ability to underwrite qualifying contracts (subject to firmness rating) reduced operating reserve costs and ability to bid into operating reserve market (if introduced)?	See response to Q39 above
41	Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?	It is hard to know, since in some cases the avoided costs are yet to be quantified.
42	Are there benefits of making a distinction between active (or controllable) and passive (not controllable) behaviours behind a connection point?	

43	How might a market participant (retailer; aggregator) provide information across their portfolio (many connection points)?	
Transmission and Access		
No further consultation questions in Part B		