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

19 October 2020

Dear Dr Schott,

Post 2025 Market Design Consultation Paper

ENGIE in Australia & New Zealand (ENGIE) appreciates the opportunity to respond to the Energy Security Board's (ESB) Post 2025 Market Design Consultation Paper ("the Consultation 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 720,000 retail customer accounts across Victoria, South Australia, New South Wales, Queensland, and Western Australia.

Overview of the post-2025 project

It is clear from the material published to date in relation to this project that the ESB has been set a daunting task. Addressing the long-term changes to the market and regulatory frameworks that may be required in the light of changing technologies and consumer sentiment in a cohesive and holistic manner is a challenge in itself. It is compounded by the fervent pace of regulatory reform taking place in the short run, which means that assessing whether the current frameworks are fit for purpose is an exercise in hitting a moving target. Chronic government intervention into markets can make it hard to diagnose whether the market is failing to deliver appropriate outcomes or whether interventions are undermining the signals that investors would otherwise respond to.

The one thing that can be said with confidence about future projections of the electricity system, even those as well-resourced and diligently carried out as the ISP, is that they will be in some degree wrong. This is not a fatal flaw – otherwise no-one would ever engage in long-term planning – but it suggests the need to be mindful on our collective limits when attempting to design today for a system in twenty years' time. With these factors in mind, ENGIE considers that the real value of the post 2025 project lies in:

- documenting the extensive reform processes in train and how they fit together;
- providing some organising principles around which to inform individual processes, so that regulatory decisions, including by different market bodies, are made on a consistent basis;

- ensuring that individual reform processes, whether carried out by the ESB or by individual market bodies are set out with reference to how they fit into the overall reform direction;
- providing high level signals as to the overall direction of reform (for example, whether it will be more market-oriented versus more centrally planned); and
- identifying likely thresholds for reform, so that reviews can be carried out as we approach the threshold rather than after the consequent problems have manifested.

It follows from this framing that 2025 should not be treated as an intrinsically relevant deadline for carrying out any of the individual reforms that may fall under this umbrella term. Reforms should take place when they are necessary, and some thought should be given to sequencing and staggering so that industry is not trying to change everything simultaneously. This approach will be far more valuable and stable for the market then any temptation in some quarters to undertake 'big bang' reform.

Resource adequacy mechanisms

ENGIE considers that the existing framework for resource adequacy; namely an energy only market with a high price cap coupled with a well-functioning contract market should remain the primary source of resource adequacy. Over twenty years this framework has performed well in delivering resource adequacy at reasonable cost to consumers, with breaches of the reliability standard remaining suitably rare.

In fact, the market has withstood the impacts of extreme weather, changing consumer preferences, a decade of uncertainty around climate policy, and chronic and ad hoc government intervention in the last few years, which is ongoing. In the light of these challenges, it's highly unlikely that any *efficient* resource adequacy mechanism would have performed materially better. The impact on investment of further uncertainty due to a fundamental change in the framework also needs consideration.

To the extent it needs adjustment, the focus should be on sharpening real-time price signals. This should in turn impact contract market prices and send a stronger investment signal. The introduction of prices for essential system services that were previously not valued in the market (see section below) should further support investment in appropriate types of capacity, albeit at the margin.

While ENGIE considers the *framework* remains appropriate into the long term, there would be merit in revisiting the parameter values of the framework, i.e. the market price cap (MPC) and cumulative price threshold (CPT). This does not necessarily require departure from the existing governance of these parameters, i.e. a four-yearly review of these settings, albeit ENGIE had some material concerns with the conclusions of the Panel in recent reviews. Notably there have been some significant developments since then, including more frequent use of the RERT, the establishment of the Retailer Reliability Obligation (RRO), introduction by COAG energy council of a new reliability standard and an interim reliability reserve (IRR) to ensure it is met, and new research on the value customers place on reliability (VCR). Together these point to a case for a material increase in the MPC. This is consistent with modelling carried out for the Reliability Panel and also with academic research that looked at high penetration of variable renewable energy scenarios.

It should be noted that the case for an increased MPC can be clearly made, and has been before, but seems fails as relying on existing reliability levers seems out of vogue and has for some time appeared politically unpopular.

ENGIE has previously suggested decoupling the MPC and CPT so as to enable the MPC to be increased to maintain sharp real time price signals which encourage investment and contracting but to set the CPT at a level which is reflective of the amount of risk a benchmark participant (i.e. highly but not fully contracted) could take. This would require a more sophisticated method for setting the CPT then simply being a set multiple of the MPC.

At the other end of the spectrum of resource adequacy mechanisms (RAMs) is a centralised capacity market. ENGIE supports the decision of the ESB not to pursue this option further. A centralised capacity market has several disadvantages compared to the current framework.

The single buyer model is less effective than a competitive model for keeping the costs of capacity procurement down. A centralised capacity market entails an administrative determination of what counts as firm capacity. Once a decision has been made, if it subsequently turns out to be inappropriate or flawed, it can be hard to change, as existing providers of this type of capacity complain that their investments are being undermined. Conversely, policymakers may be slow to recognise innovative ways of providing capacity. In both cases, a ongoing decentralised, informal approach based around commercial incentives will be able to respond more flexibly.

Finally, as the market operator or other party responsible for determining the quantity of capacity to be procured is incentivised reputationally rather than financially, there will be a tendency for over procurement. All of these issues can be observed in existing centralised capacity procurement mechanisms, such as that of the Western Australian, Wholesale Electricity Market (WEM).

Perhaps the best that can be said of the WEM's capacity process is that its administrative price setting (based on the modelled cost of a gas peaker) represents a stable long-term price signal for capacity. Other, more dynamic capacity markets, such as the PJM, see fluctuating prices year-to-year. So, a capacity mechanism can either provide clear long-term price signals or be relatively efficient (albeit with the disadvantages set out above) but not both.

Some of the options still under consideration have some of the same issues. A decentralised physical capacity market may benefit from the competitive tension of multiple parties procuring capacity but retains the disadvantage that the definition of qualifying capacity must still be administratively determined.

In practice the same is likely to be the case with the RRO. Even if there is on the face of it scope for retailers or other liable parties to propose alternative ways to meet their liability to the regulator, such a process can be lengthy and costly, and it is easier for them to default to the prescribed forms of compliance. Moreover, it should be noted that: the RRO was originally promoted by the ESB as one part of the National Energy Guarantee and the other part has not materialised; it has only recently been triggered for the first time, in one region, and due to ministerial instruction rather than a defined capacity shortfall; and the time period covered by this trigger has yet to pass. In other words, it is essentially an untested policy and it is premature to look to reform it and give it more weight in ensuring sufficient capacity. A more critical view would suggest that any support for reforming the RRO is based on the implicit acknowledgement the RRO provides questionable value and could be removed.

With these factors in mind, if the ESB still considers that the existing framework requires some complementary mechanism to instil confidence in consumers that the market will deliver reliable supply, the options of a price adder or a formal operating reserve are the most appropriate for further development.

In the case of an operating reserve, the systems costs of integrating the operating reserve demand curve into dispatch and co-optimising with energy could be material. With this in mind, a manual adder process may be quicker and cheaper to implement and therefore be the better option of the two in the first instance. To the extent the adder turns out to be a valuable contributor to reliability, then the net benefits of converting it into an operating reserve can be evaluated. In either case, the efficiency and effectiveness of the mechanism will be primarily determined by the appropriateness of the administrative demand curve. In terms of the design of an adder, the ESB would do well to consider the example of the Texan ERCOT market, which is another successful energy-only-market, that uses an adder to bolster reliability. Crucially, the Texan ORDC provides a price signal that can reward standby plant which better values capacity that is valuable but may not be called upon (an effective system service).

Ageing thermal generation strategy

ENGIE considers that the most relevant tool for managing the exit of ageing thermal generation, the Notice of Closure provision is already in place and the case for additional regulation to address this issue is limited. As the Consultation Paper acknowledges, other workstreams, especially on RAMs and essential system services will assist the market in adjusting to these exits.

Plant operators are best placed to identify whether and when the performance of ageing plant gets to the point that it cannot be relied upon for firm capacity. This will then manifest in their reluctance to sell swap contracts (or similar) because they will be unable to confidently defend them. The existing resource adequacy mechanisms (i.e. normal market operations), will signal that there is now unmet demand for firm capacity and the market can be relied on to deliver it, providing it is allowed to work as expected. To the extent that there are issues with this discovery process, they are unlikely to be capable of being regulated away in any case.

On the face of it, some of the options under consideration, such as, ramping up the penalties for early exit may appear to be a "free pass" for consumers, since they will not bear the cost of the penalties. However, further thought should be given to unintended consequences. The higher the stakes from an unexpected event that leads to early closure (e.g. a significant unplanned outage where the maintenance cost to get the plant back online for its final few months or a year outweighs the benefits from returning to market), the more conservative plant operators will be with their notice date. This could result in some plant leaving the market earlier than otherwise which could in turn engender higher energy costs to consumers.

It is important to note, the decision to close a large asset is a complex one involving many factors and multiple decision points. Decisions on timing often cannot be easily pre-judged and as plant reaches the end of its life a full understanding of physical plant limitations and evolving safety concerns may not be able to be predicted 5, or 3, or even less years out. The ESB, and others, may be better served focussing less on predicted closure dates and more on a predictable investment environment.

Essential system services

ENGIE agrees with the ESB's assessment that the energy transition away from large thermal, synchronous plant, is creating the need for a greater range of explicit procurement processes for essential system services and notes the large volume of reviews and rule change processes in train in this respect.

ENGIE also supports the ESB's preference to use market mechanisms where feasible. Market mechanisms - which can range from structured procurement (such as SRAS) to co-optimised spot markets (such as FCAS) should be open to the widest range of participants and technologies that can supply the services needed. This may vary from service to service, but would likely include: existing synchronous generators, who have historically provided many of these services, often without remuneration; inverter based resources where feasible – initial deployment of such plant has rarely included the ability to provide such services, but that is changing and with appropriate price signals, there will be incentives to design plant and inverter settings accordingly; TNSPs, who may be well placed to contribute to the provision of services such as system strength and inertia, as ElectraNet is doing in South Australia; and demand side resources, such as VPPs and DR providers, both of which have entered the South Australian FCAS market.

The alternative of tasking TNSPs with providing adequate system strength or inertia carries risks of inefficient procurement, noting the AEMC's findings that there is a risk of a capex bias in the network economic regulation framework[1]. Accordingly, the possibility that TNSPs may invest in self-owned assets (capex) rather than procure from third party suppliers (opex) even where the latter is more efficient cannot be discounted. Effectively procuring services from synchronous generators separately from the supply of energy and other services is a challenge even aside from the risk of capex bias. These considerations may make AEMO better placed to procure any services that do not appear suitable for a co-optimised spot market and allow TNSPs to compete against other service providers on a level playing field.

Spot markets are (or should be) highly dynamic which can result in volatile revenues. In the energy market, the solution to this is the contract market, which allows the conversion of volatile 5-minute revenues into quarterly, annual or multi-year fixed revenues. This characteristic, which can be termed hedgeability is crucial. So, where spot markets are being contemplated, their hedgeability must be considered. This is also important on the load side as contract markets allow large users and retailers to manage their costs. Elements of the bill that are not currently hedgeable, such as RERT costs, are becoming an increasing concern for large users.

With these points in mind, ENGIE is broadly supportive of the Consultation Paper's proposed direction of travel from directions and self-provision (which are not sustainable and efficient approaches in the long run for some services) towards structured procurement and co-optimised markets for services. In doing so, the ESB should ensure alignment with existing processes, most importantly the AEMC's consideration of several rule change proposals that it collectively terms system security services.

Scheduling and ahead mechanisms

ENGIE supports the ESB's view that there is no merit in pursuing mandatory ahead settlement of energy co-optimised with system security services. Further, ENGIE considers there is limited value in pursuing a voluntary ahead market for energy. The rationale for such a market would be broadly the same as that for the proposed short-term forward market that the AEMC considered earlier this year. The AEMC concluded that none of the three targeted groups of participants (renewable generators, demand response providers, and flexible gas plants)

[1] Economic regulatory framework review: 2018 Final Report, AEMC, pp. 14-37

saw much value in this type of market compared to their existing risk management options and that in any case, voluntary financial markets were capable of being created if sufficient demand for short-term hedging arose[2].

The proposed Unit Commitment for Security approach (UCS) appears a pragmatic way to streamline existing manual processes and schedule system security contract providers. The potential move to the next option, where some services are scheduled ahead of time may benefit from more detailed consideration of the costs and benefits. These seem likely to be restricted to costs and efficiencies related to AEMO's procurement processes rather than trade between market participants, given the limited appetite AEMC found for short-term ahead trading.

Two sided markets

ENGIE agrees with the ESB's assessment that if the NEM operated as a two-sided market, there could be valuable efficiency gains for consumers, reliability could be managed by disaggregated consumer signals as to their own value of reliability, and dynamic load response would help manage the variability of a supply side with a very high penetration of renewable plant.

In practice the pace of reform towards a truly two-sided market is limited by customer appetite to engage with service offerings that entail their load being treated as a flexible resource. Unlike the supply-side, providing resources to the market is not the primary role of the demand-side. Businesses value supply continuity in order to ensure continuity of processes and access to lighting and HVAC. Households typically expect to be able to use appliances when and how they choose, rightly so.

In principle emerging technologies (and mature technologies used differently) can be combined into a service offering for customers of all sizes that could work "behind the scenes" to deliver price-responsive load flexibility for little to no effort or loss of amenity on the customer side. This will generate savings that can be shared with customers. But for small customers, in particular, the savings – even though they may appear to be more or less "free money" may never be sufficient to motivate them to sign up for such service packages. This is evident in customer research on how much customers consider they would have to save to be motivated to simply switch retailer, let alone to engage with more dynamic service provision.

To the extent the ESB is confident that two-sided market can be developed over time, it is important to consider the implications for the longevity of other mechanisms, both those in place and those being contemplated. The wholesale demand response mechanism would have no place in a two-sided market as DR providers' willingness to adjust their consumption at certain price levels would be signalled through the dynamic demand curve. It's also questionable whether administrative assessments of required capacity levels in future years, which are a component of some of the RAMs under consideration, would have much meaning in a market where demand was flexibly responsive to price.

Valuing demand flexibility and integrating DER

While a two-sided market is an aspiration, albeit a worthwhile one in principle, DER integration is emerging as a necessity for a secure electricity system. Large generators, while free to bid in at whatever price they like to supply energy are also subject to rules that allow AEMO to direct them on or off, to constrain their output, or to

[2] [Short term forward market, Rule determination, AEMC, March 2020]

effectively write off a material proportion of output through the MLF framework. More recently, generators that can provide primary frequency control have been required to do so without compensation. The purpose of all these rules (setting aside concerns ENGIE may have with the way some of them work) is to give AEMO the tools to maintain a reliable and secure system. Distributed rooftop PV is often called “Australia’s largest power station” because its aggregate capacity in each region exceeds that of any individual large-scale power plant. Yet it has not been subject to equivalent requirements to provide services to the grid when necessary.

Of course, there are practical and social challenges to imposing requirements on millions of households and businesses in the way similar to large power plants. In both cases, it is preferable that such requirements are a last resort to be used only when the incentives inherent in price signals fail to deliver the necessary resource mix. And unlike large power plants, where intervention in the output of rooftop PV is necessary, it will likely need to be centrally controlled - by the local DNSP or AEMO depending on how the system architecture is developed.

The process of developing the price signals for distributed PV will be different from that for large scale plant. Retailers (and potentially other service providers) have a key role to play in managing price risks on behalf of customers. This can and should apply to price signals for system services and/or those that arise from networks as well as from the wholesale market. Just as retailers do not pass through volatile wholesale prices to customers (unless they request it), they may not pass through network price signals. This doesn’t in itself negate the price signal; the key is understanding the tools available to manage that risk - whether in the hands of the retailer or the customer. Risk management can take the form of physical tools - technology has a key role to play here - or financial risk management tools.

Conversely, if the signals remain internalised inside DNSPs, then they will respond with the tools they have and which suit them, while other potential solutions and providers of solutions cannot emerge and be deployed.

This means that the pace of tariff reform must be tailored to the availability of relevant technologies and financial risk management options. This is of course an iterative and somewhat endogenous process, as technologies will only be deployed in response to demand, in which price signals will be a factor, and the development of financial tools may depend on the characteristics of the price signal. There is a balance to be taken by the ESB and the energy market bodies in shaping and driving tariff reform, and in allowing participants to work out the most effective tariff structures. But consistency across distribution networks is important, and it may help to resolve the current ambiguity around whether network tariff signals are aimed primarily at retailers or customers. As noted above with reference to two-sided markets, customer appetite for taking up new tariff shapes, or service providers’ physical risk management options such as direct load control, may be limited and will dictate the pace of change.

ENGIE agrees that the changes to the system and the market that will arise from moves towards a two-sided market and greater integration of distributed resources warrant reconsideration of the customer protections framework. The undoubted importance of having strong, clear customer protections must be balanced against the need to allow for innovation in the market, which inevitably entails some trial and error and thus is not risk-free either for customers or service providers. Additionally, as the role of customers, retailers and DNSPs evolves and as different types of service provider join this ecosystem, then the current paradigm of allocating rights and responsibilities based on supply chain roles may become outdated. Rather, rights and responsibilities may be more optimally allocated to services provided.

Transmission access and the coordination of generation and transmission investment

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

Nonetheless, the AEMC is making progress with its access reforms, and ENGIE agrees that the ESB should factor this reform plan into the overall post-2025 framework, noting that there needs to be a cross-check against any market reforms for resource adequacy and how they interact with the access reforms, which are predicated on a continuation of the energy-only market. While the ESB is well-placed to take this holistic view and consider how other reforms affect the locational marginal pricing and financial transmission rights, this should not become an opportunity for re-prosecution of the merits of previous regulatory decisions.

Meanwhile there has been significant development on the planning side with the introduction of the ISP, the streamlining of planning decisions through the actionable ISP rule changes, and now consideration of the best ways to develop renewable energy zones (REZs). The signals from the ISP are that transmission investment is required at a greater pace than has previously been the case. This means that the value of ensuring investment efficiency has never been greater and that the benefits of each proposed investment should be rigorously assessed.

Nonetheless, the current RIT-T process remains a relatively blunt instrument. The decision to proceed is based purely on a high-level net benefits test and once approved, customers must pay for the resultant infrastructure regardless of its level of utilisation. In other words, there is no cost to proponents for being wrong. As recent RIT-T processes have shown, benefits can fluctuate widely with plausible changes in input assumptions and costs are little more than placeholders, as the real cost is not evident until detailed design work is carried out *after* RIT-T approval. This process is not conducive to efficient price discovery for transmission services. There may be an opportunity to explore greater use of competitive procurement tools for transmission extensions – AEMO's experience in Victoria may usefully inform the feasibility of such an approach.

The introduction of REZs provides a further opportunity to explore alternative models based around commercial development as opposed to a regulated approach. So, scope should be allowed for a REZ design report to be initiated by parties willing to fund a REZ, noting that the options for recovery of design report costs may need some consideration. Additionally, to mitigate the "lottery effect" whereby some generation proponents will be advanced over others in the zone because they happen to end up closer to the preferred design option, design options could be weighted based on generation proponents' willingness to contribute to the investment. In this way, they can have more influence over the design in return for offsetting the costs that consumers would otherwise bear.

In the absence of proponents of large scale interconnection and REZs having more "skin in the game", it is almost inevitable that transmission will be overbuilt with many private benefits paid for publicly and the ultimate cost of any overbuild ending up in consumers' energy bills.

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