SUBMISSION

ESB POST 2025 MARKET DESIGN CONSULTATION PAPER
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EUAA
Energy Users Association of Australia

The Energy Users' Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade.

Our members are highly exposed to movements in both gas and electricity prices and have been under increasing financial stress due to escalating energy costs. These increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items.

We welcome the opportunity to make a submission to the Post 2025 Market design Consultation Paper (Consultation Paper) and acknowledge the significant amount of work undertaken by all of those involved with the ESB.

Introduction

Government Interventions.

The active and increasing level of direct intervention by Commonwealth and State Governments has meant it has been difficult to respond to the ESB's proposals. We fundamentally see reliance on market-based measures as central to an efficient NEM that is in the long-term interests of consumers.

Our members understand that Government intervention with tax-payers money does not impose specific costs on energy users, but when the risk averse driver of this intervention also drives other market measures that create a very conservative regulatory framework, costs are imposed on consumers who are not best placed to bear that risk and who certainly are not prepared to pay the additional cost when the benefits of that conservatism appear to be small.

This interplay of politics and market measures is perhaps best seen in discussion around the RRO. We do not support any change to the existing RRO, yet a physical RRO seems to have strong support from the Commonwealth Minister and perhaps some State Ministers. Therefore, the Consultation Paper seeks views on RRO options when the politics suggests that only one option has any chance of success. In this context we question the worth of spending a lot of time in this submission arguing our position that we may perceive has no chance of influencing the debate.

Additionally, we do not support a capacity market at this time as we believe the evidence to support it has not been established. While it seems the ESB agrees with this, the political pressures to move toward a capacity market and increased AEMO/Government intervention has meant that for the ESB to develop a workable framework capable of being accepted by Ministers, it has had to move in a direction it may not have supported when the post 2025 review began.

Expensive Conservatism.

We can see that the transition to higher levels of renewables is proceeding at a pace that is much quicker than most expected, even a few years ago. As the old energy system is pulled down and replaced with the new, we are witnessing a form of creative destruction as the energy market undergoes a paradigm shift. When you combine this with a highly conservative political view of what consumers expect, we can understand why AEMO (who already takes a very conservative approach) takes an extremely risk averse approach to running the NEM in this time of fast transition.

Unfortunately it seems that any Unserved Energy (USE) is perceived as a failure on AEMO's part, so conservative forecast methodologies (e.g. peak demand estimates, what generation is included or excluded from the various reliability assessments, etc) and support for a range of direct non-market intervention measures are seen to be necessary.

We see this conservatism in many places. The Interim Reliability Standard of .0006 is a prime example. The actual reliability standard of .002 represents the trade-off between reliability and costs that consumers are prepared to make. Consumers were not consulted during the interim standard's development, have never supported it and believe it is entirely unnecessary. The most likely outcome of this interim standard is increased costs for no material improvement in reliability.

Another example is the RRO, which has never been triggered (i.e. T-1 trigger) even against the interim reliability standard We see this as a success because the safety-net that it represents has never been needed, meaning market participants are meeting their obligations without the need for further intervention. In many cases the threat of an external action is sufficient motivation. However, it seems that the non-triggering of the RRO is somehow seen as a failure. Why? Because it hasn't been triggered? It's akin to saying that your car insurance has failed because you have never been in a collision.

We see many examples of this overly conservative approach and remain concerned that we end up with significant increases in consumer bills as we chase what we consider to be a politically driven reliability standard (100%) or other politically desirable outcomes rather than a system that balances cost, risk, reliability and sustainability.

The Balkanisation of the NEM.

We are growing increasingly concerned with State Governments implementing their own, significant policy agendas (e.g. NSW Roadmap, VicGrid) that seem to put State interests above NEM interests. While this is understandable from a State Government perspective, it is unlikely to lead to the most efficient allocation of resources leading to higher costs for consumers.

For example. From our observations even if it is cheaper for NSW consumers to bring renewable energy from Queensland into NSW on QNI, NSW does not seem to be interested. They only seem to want NSW projects to contribute to the NSW system because they have regional development benefits, they enable a state based level of reliability to be achieved and they contribute to state based environmental targets. It seems that rather than interconnectors being the great energy freeways that allowed participants to freely trade across boarders in an efficient manner, they go back to an insurance policy role when state-based generation is insufficient.

While the ESB has included some sensible proposals for a common approach to integrating jurisdictional schemes for new investment in the NEM to achieve a national approach that is in consumers best interests, we fully expect State Governments will continue to do what they wish irrespective of whether it accords with any common approach.

We understand the ESB has done extensive consultation with the various jurisdictions to understand whether the proposed ESB reforms will get Ministers' support. Many of the 'options' presented in the Consultation Paper are already the subject of rule change processes where we are separately engaged (e.g. some of the 'immediate and initial reforms'). We understand that those reforms that are not in that category will be the focus on Ministers' considerations. Given our perception that consumers have limited influence on political decisions that are being made, we have taken the approach in this submission of providing only high level comments as we await Ministers' decisions.

The EUAA and its members have spent considerable time being involved in the excellent stakeholder engagement process undertaken by the ESB over the whole post 2025 NEM process. We thank the ESB for its willingness to engage and make themselves available for specific member briefings.

Resource Adequacy Mechanisms

Firstly, it should be acknowledged that wholesale (generation and bulk transmission) is only responsible for a very small proportion of total interruptions to supply in the NEM. Apart from 2009, when Victoria and South Australia experienced unprecedented power system conditions in late January and early February 2009, the reliability standard has been met in all jurisdictions since the start of the NEM.

Historically, supply interruptions are dominated by issues in the distribution system. But we recognise the future risks. The Reliability Panel's latest Market Performance Review for 2019/20 noted that[1]:

> *"…while the reliability standard was met in each region in 2019-20, the system operator faced significant challenges maintaining operational reliability during the reporting period. This was due to the number of extreme environmental events, such as the bushfires, that impacted the power*

[1] AEMC Reliability Panel p.v https://www.aemc.gov.au/sites/default/files/2021-05/Final%20report.pdf

system during this period. The difficulty in managing reliability is evidenced by the increased number of occasions when interventions were necessary, as well as the increase in actual LOR2 conditions in 2019-20. Furthermore, there was an increase in the number of tight supply-demand forecasts in non-peak periods that have traditionally not presented challenges of this manner."

Currently the market has a number of reliability assessment mechanisms and a range of measures to assist market participants, AEMO and Governments to assess these risks e.g. ESOO, MTPASA, STPASA, Energy Adequacy Assessment Projection and the 42 month notice requirement for closure.

In recent years the ESOO has forecast potential shortfalls to the reliability standard but they have not occurred as the market responded to the information as it is meant to and actual demand outcomes fell well below AEMO's conservative forecast of peak demand.

Similarly, in the dispatch timeframe, whilst AEMO may have forecast LOR conditions, the incident of instructed consumer load shedding has been rare. While incidents of AEMO declaring actual LOR's is noted as having increased, it is less clear if this is due to AEMO over forecasting as opposed to actual power system conditions at the time (given actual LOR is based on AEMO's generally conservative forecasts of outcomes, not actual dispatch conditions).

Governments have also responded to any perception, no matter how small of the potential for USE, e.g. the Commonwealth Government's decision to build the Kurri Kurri gas fired station, the NSW Government's inclusion of 2GW of storage by 2030 in their Roadmap and the Victorian Government's support for Yallourn to stay open until 2028.

Our members see all this occurring – often driven by political rather than economic reasons. They understand the issues and risks discussed in the Consultation Paper, but they are not convinced they should support measures that impose additional electricity market costs on them when there does not appear to be sufficient evidence of a problem and when Governments are aggressively addressing the same risks through the political process and Government budgets. This seems to be an unnecessary and potentially expensive path forward.

<u>NEM-wide information provision and financial principles</u>

We support the proposed co-ordinated approach to government underwriting schemes to help ensure investment driven by these schemes is better integrated with existing market design. Our only comment is that recent experience suggests implementation of an integrated scheme is unlikely.

Governments will continue doing what they want to do. They may seek to show alignment with any NEM wide principles and a high level of transparency, but we are not confident it will be substantive. We expect it will be AEMO seeking to interpret what the jurisdictional schemes might mean in practice and then incorporating them in AEMO's unique way in their suite of forecasting documents e.g. ESOO.

Enhanced exit schemes

We support the need for more information around generator mothballing decisions and how this may be used to circumvent the 42 month notice period. We consider that an extension to the MTPASA reliability assessment to 36 months will provide an initial first step assessment regarding the reliability impact of any generator mothballing decision. We see merit in the proposed additional information collection framework to allow a complete System and Market Impact Assessment by State Governments alongside the AER's exemption decision.

We also support the concept of an Orderly Exit Management Contract, noting, as the Consultation Paper does, the moral hazard such a contract can give rise to. There are many lessons to be learned from a previous Commonwealth Government's attempts to negotiate contracts for closure of coal fired power stations when generator owners had quite a different view of the value of their power stations than the Government.

It is important that the terms of any such contract be transparent to ensure appropriate public scrutiny on the claimed costs and benefits, especially if the costs are to be recovered from consumers e.g. through DUOS charges. However, if the Victorian Government's agreement with Yallourn is any guide, then transparency is unlikely.

Modifying the Retailer Reliability Obligation

The RRO must be the most discussed specific market measure in the history of the NEM with the initial measure changed a number of times since its introduction to effectively tighten its application. Even with the interim reliability standard of 0.0006% there has only been one T-3 trigger declared - for NSW in January 2024 with the Liddell closure. Given recent experience we fully expect this to disappear well before the T-1 trigger decision will need to be made.

The ESB is in a difficult position. It supports the market but recognises the effect of Government interventions is creating uncertainty to private investors (p.31):

> *"…jurisdictions have continued to announce ambitious renewable energy targets along with mechanisms to underwrite existing or new dispatchable capacity. These mechanisms have the potential to dampen investment signals from the NEM spot and contract markets and so shift investors' risk out of the energy only market and distort the signals for others. This may lead to reduced contracting for investment in dispatchable resources and potentially impact on exit and closure decisions in relation to large scale ageing generation plant."*

The ESB's argument is that a 'modified' RRO will provide the necessary 'space' to:

- *"Promote commercial investment to improve reliability, rather than government underwriting reliability risks, and/or*
- *Reduce the likelihood of a generator unexpectedly exiting the system, and/or*
- *Ensure there is a minimum amount of liquidity and contracting in the derivative market to support transparency of future price expectations."*

and hence allow the real time market to continue doing the 'heavy lifting'.

We are not convinced. It seems to us that the ESB is caught in a catch-22 situation. They want to believe that the 'modified' RRO will mean Governments cease their intervention and hence the costs of the modified RRO to consumers are justified. We do not see any evidence that Governments will stop their intervention even with a physical RRO. Hence we do not consider the 'modified' RRO will achieve its 'six key measures of success'. It will only result in higher costs to consumers (what the ESB refers to as 'increased regulatory burden') without commensurate benefits.

We do not consider the additional costs of either Option 1 or Option 2 (the political preference) are in the long term interests of consumers. We do not support any change to the existing RRO. However, irrespective of which option the ESB recommends, we would support:

- the MTPASA reliability assessment being extended to 3 years to provide regularly updated information to the market, and
- inclusion of an enhanced market liquidity obligation on generators; it seems unfair to have a situation where market customers *must* buy complying contracts or capacity certificates, but generators only *may* sell.

Essential System Services, Scheduling and ahead Mechanisms

We agree with the urgency to ensure sufficient essential system services given the exit of synchronous plant and are supportive of the FTI framework. We support the ESB's preference for market-based approaches for these services e.g. spot market for inertia and fast frequency response.

We remain concerned by proposals for long term contracting by AEMO under the UCS mechanism as we consider this will result in conservative procurement of services by AEMO and increased costs to consumers.

<u>Immediate reforms</u>

Fast frequency response

We have recently made a submission to the AEMC supporting its Draft Determination on the Infigen fast frequency response rule change. In particular we:

- Supported Option 1 - new market ancillary services for FFR i.e. a total of eight contingency services. We were concerned about the decrease in level of service competition from the AEMO proposal to amalgamate the 6 and 60 second services. This will inevitably result in reduced competition and higher costs to consumers.
- Supported the Shell Energy (an EUAA member) submission proposing an alternative model whereby the existing 6 second service be changed to an 8 or 10 second service. This change also has the potential to increase competition in the provision of the 'fast" services and reduce costs to consumers.

Primary frequency response

The EUAA supports this reform.

Initial Reforms

We have had many discussions with the AEMC on the Transgrid rule change. Our views is:

- We agree with the demand side element of new access standards to ensure future connecting parties' plant has a minimum level of system strength performance
- We have concerns around the supply side and co-ordination elements given it will be a TNSP prescribed service. While we support connecting parties paying for system strength services and the prices based on AER pricing methodology guidelines, consumers may be left with significant stranded asset risk given the contracts seem to be only 5 years duration and the asset life of the capital employed by the TNSP considerably longer.

Operating reserve

We are not convinced this is required and that seemed to be the conclusion from the modelling presented by the ESB to the Technical Working Group. The case has not been made that this would lead to any additional benefit greater than costs above what existing market settings achieve.

Unit Commitment for Security and System Security Mechanism

We are supportive of the UCS model where AEMO can schedule contracted resources ahead of time to keep the system secure, but this should occur only when pre-dispatch indicates current pre-dispatch outcomes are inadequate to provide the required system services. The risk, like all centrally procured services, is over provision where consumers bear the cost. This will require AEMO to develop transparent rules on how procurement will be determined.

We are not convinced that we need both UCS and SSM given they seem to overlap in purpose. We have also had the opportunity to review an alternative proposal from Shell Energy Australia (an EUAA Supporting Member) to facilitate a cost-based compensation framework within the rules which would allow constrained on generation to recover their costs of complying with an AEMO issued dispatch instruction.

We believe this proposal has merit and should be trialled prior to implementing UCS or SSM procurement.

Integration of DER and Demand Side Participation

It is clear that the energy system, traditionally a one-way street where energy was sent to consumers, is being used in ways that were not envisaged when first constructed. This requires new ways of managing the energy system and charging for its use to ensure a just transition is achieved.

It is also clear that technical standards need to continually evolve as new technologies are connected into the system. At first many of these new technologies such as solar PV did not have a material impact on system strength or the ability to manage the system. However, as the ESB notes:

"Technical integration of DER is needed to ensure that a reliable and secure system continues; arrangements need to support service providers to interact with the wider systems and wholesale market;"

As with other aspects of the ESB P2025 work we seek market based solutions where possible (as opposed to direct intervention from market operators or governments) where the guiding principle of "beneficiary/causer pays" are observed.

<u>Integration of Distributed Energy Resources (DER)</u>

We have not been deeply involved in the integration of DER work but would offer the following general comments:

- We are very supportive of the "Access, Pricing and Incentive Arrangements for Distributed Energy Resources" rule change proposed by St Vincent de Paul Society Victoria and subsequent Draft Rule Determination by the AEMC[2] (released on 25 March 2021) which allows for Network Service Providers to charge for exports into their network. We believe this follows the "beneficiary/causer" principle that we see as fundamental to an equitable and well-functioning energy market of the future.
- We see the principle of paying for the export of generation as important principle as it recognises that with the changing nature of our energy system comes a range of new participants who benefit

[2] https://www.aemc.gov.au/sites/default/files/2021-03/Draft%20Determination%20-%20ERC0311%20and%20RRC0039%20-%20Access%20Pricing%20and%20Incentive%20arrangements%20for%20DER.pdf

from it. It also recognises there are those who can't take advantage of new technology to reduce their exposure to network costs who may end up paying a disproportionate amount of these costs leading to unfair and inequitable outcomes.
- This principle not only applies to DER but should also be considered as part of reform of the transmission/distribution pricing rules where the EUAA and others have been calling for a more equitable allocation of costs and risks associated with significant network upgrades like that which is contemplated by the AEMO ISP.
- While some problems will be solved via traditional network solutions (i.e. building bigger grids), we support further work on the role that non-network solutions can play. We note that AEMO have run a number of successful "virtual power plant" trials as have a number of retailers.
- The ability of AEMO to have greater visibility of what is going on in the system, particularly at distribution level, is becoming increasingly important and we support further work in this area.

Regarding the immediate and initial reforms proposed by the ESB:

- We support further development of a risk assessment tool that helps assess the type of consumer protections that may be required as new forms of energy services emerge.
- We agree that backstop measures deployed in South Australia to manage minimum demand scenarios where output from rooftop PV was constrained by AEMO is not ideal. We see this as an opportunity for community batteries to develop within the DNSP that soaks up excess solar in times of low demand and then dispatches at times of high demand. We are aware of initial trials being undertaken by a number of NSP's in this area and encourage further work by the industry and rule makers to deliver these outcomes at least cost and greatest benefit to customers.
- We support further work to streamline and improve customer participation in DER and work that enhances customer choice and flexibility provided it does not come at the expense of system strength.
- We are supportive of further work to develop appropriate technical standards for new DER, especially standards that places the responsibility of maintaining system strength on the asset owner and/or technology provider. As a minimum, any asset, regardless of size, must not contribute to a reduction in system strength.

<u>Demand Side Participation</u>

The EUAA are strong supporters of greater consumer participation in energy markets and are strong supporters of the Wholesale Demand Response Market (WDRM) concept. We recognise that if consumers are participating in energy markets that some guard rails need to be installed to ensure transparency and accountability so that markets continue to operate fairly for all participants. However, a balance between transparency/accountability and facilitating/encouraging participation needs to be achieved. Based on EUAA member experiences to date, this balance if not being achieved.

We offer the following insights based on member experiences to date of working on the WDRM rules and engagement with the ESB over the past 12 months:

- Energy users should not be viewed as energy market participants (at least not in the traditional sense), when they participate in a WDRM. This is because energy is an input to facilitate the primary function of their business such as making steel, glass, paper etc. Treating them as market participants, including strict compliance and penalty regimes, will simply discourage direct participation.
- Large Commercial and Industrial (C&I) energy users are not a homogenous group of customers. Their ability to participate in demand response varies on a site by site basis.
- It is highly unlikely that large C&I energy users will actively pursue demand response from core functions of their business as the potential reward is unlikely to exceed the cost of lost production and costs associated with installing control systems, training etc . Therefore, we think the amount of demand response that can be extracted from large C&I energy users is likely to be over-estimated.
- If large C&I energy users were to participate in demand response it would most likely be from secondary systems or embedded forms of generation (on-site gas turbines, heat recovery/cogeneration etc). Over time this may represent a significant amount of demand response, but it’s not available today.

Currently, large C&I customers participate in demand response in a number of ways:

- Controlling secondary systems to manage a level of spot price exposure.
- Participate in a retailer demand response program.
- Participate in RERT.

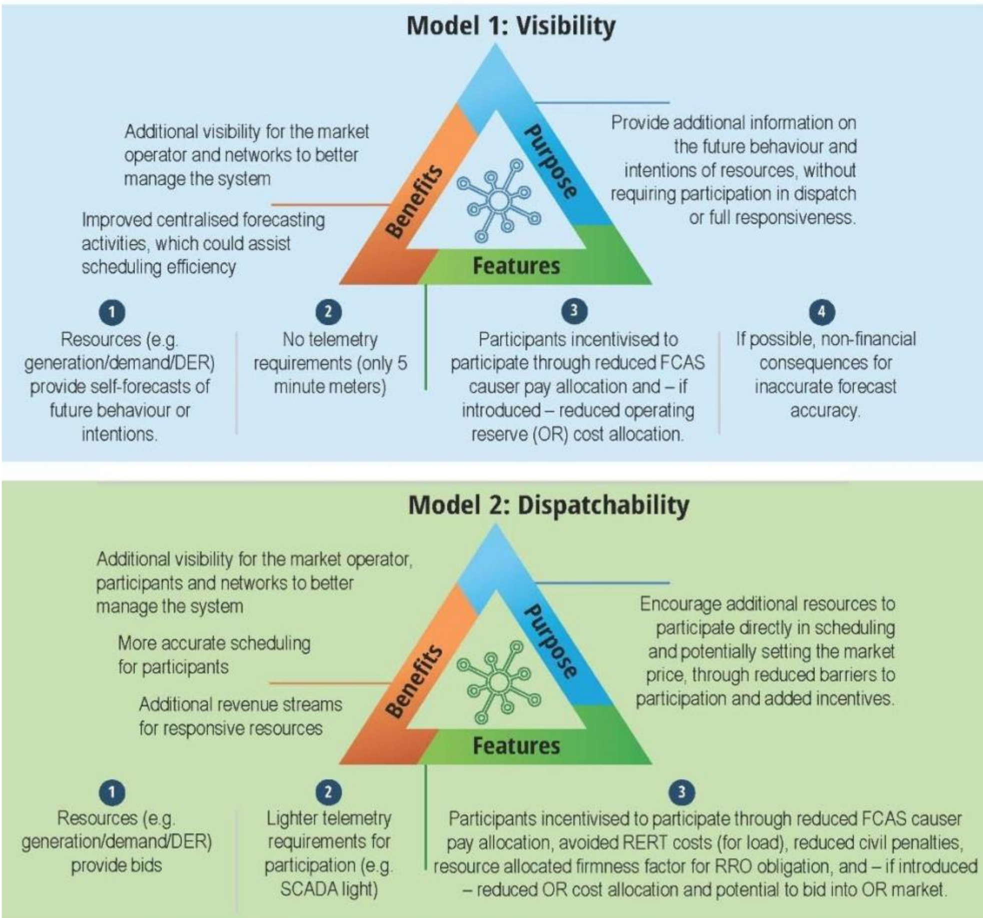
All three of these current modes of participation represent relatively low risk opportunities for large C&I energy users to extract value from any flexible loads they may have.

- In the case of using demand response to manage spot market exposure. It is an internal function of the business simply used to avoid a high price event. Therefore, there are no costs or risks associated with compliance or market participation.
- In the case of a retailer demand response program, the retailer manages the market interface and takes on all compliance functions and risk. While the customer may not receive full value of their flexible load (i.e. a percentage of spot price saving would be passed through) there is very little risk.
- In the case of RERT. Many EUAA members actively participate in the short notice RERT program administered by AEMO with a much smaller group also participating in long-notice RERT. RERT is very low risk for large C&I customers who can choose when they participate and are not penalised if they don’t.

All three approaches represent an easier, lower risk way to participate in demand response and may offer an opportunity for large C&I energy users to become more comfortable with the concepts of the WDRM over time. However, for these same companies to participate directly in a WDRM a similar risk profile needs to be facilitated, at least in the formative stages of the market. We are yet to see this in any of the discussion's members have had to date. Therefore, the incentive is to continue with their current mode of operation.

The exception to this may come about as more demand response aggregators enter the market. If aggregators take on the compliance risks and market interface in the same way that retailers currently do then it may prove to be an attractive proposition for some large C&I energy users. At the very least the WDRM should encourage the entry of these entities into the market and increase competition in this space.

To address concerns raised by consumers, the ESB have developed a Scheduled Lite approach. We appreciate the effort by the ESB to develop a less onerous model of consumer participation in wholesale markets and we acknowledge these would provide an easier means of participation for consumers.



However, while the requirements and obligations of participants is lower than if participating directly via the WDRM, the benefits flowing to participants are also lower, especially given they will not access any benefit from spot prices under either model. While this is understandable (less risk = less reward), further analysis would need to be undertaken to assess if the reduced value proposition justifies any cost incurred by participants (both measured by dollars spent and time allocated to the task) and if it represents a superior value proposition to the three current modes of activity.

We do see opportunities to develop these concepts further as they may represent another, less onerous entry point to the WDRM. Therefore, we think the ESB should consider further work and stakeholder engagement on both models, considering that they would be implemented simultaneously as stepping stones to WDRM participation.

While these are positive initiatives, we are concerned with the following statement appearing on page 70 of the Consultation Paper and discussed at deep dive sessions over the past 3 months:

The ESB notes that greater use of mandatory approaches may be needed in the future if:

- *a voluntary system was not able to achieve a balance of obligations and incentives that could deliver value in the long-term interests of consumers*
- *operational inefficiencies caused by a lack of visibility accelerated faster than voluntary measures could adequately address.*

We are very concerned if mandatory approaches were pursued that forced large C&I energy users to participate in a scheme that may be damaging to their business by way of lost revenue, increased costs or damage to plant and equipment. We seek clarity on this issue and assurances that large C&I energy users will not be required to participate in mandatory approaches.

Transmission and Access

We appreciate the complexity of any reform that seeks to change network access and charging arrangements. In particular, the existing open access regime always looms as an immovable object in the way of reforms that would be in the long-term interests of consumers.

However, we are also seeing that demonstrating net benefits and gaining regulatory approval for large transmission assets, including REZ, is becoming more difficult, in part due to the existing regime requiring that consumers carry all costs and risks.

We believe it would be in the best interests of all parties (consumers, renewable energy proponents, networks and governments) to find common ground on a more equitable cost and risk sharing arrangement. If the desire is to see rapid deployment of renewable energy then everyone needs to be satisfied they are being treated fairly and that each party bears risks and costs that are within the power to control.

We have made numerous submissions on this subject over the last 5 years, including to the work undertaken by the ESB on Renewable Energy Zones (REZ) so our position should be well known, however it is worth repeating.

What we are looking for is Equitable Cost and Risk Allocation.

The existing cost recovery model for regulated assets assumes that society in general is the sole beneficiary of the investment, therefore all costs should be fully socialised. This is reasonable provided all benefits are also fully socialised, which progressively they are not.

As we embark on a once in a lifetime rewiring of the NEM we are constructing new transmission assets, primarily to move new forms of generation to major load centres. In the case of REZ, the sole purpose of these new assets is to facilitate significant new generation, the majority of which is privately owned and operated. These generators, who have a first responsibility to deliver profit for shareholders, are set to gain significant financial benefit from these assets while consumers are asked to cover the entire cost and long-term risks associated with this access.

It must be recognised that consumers have no control over where these assets are being located nor do they have any control over the financial viability or operation of these assets, but are currently expected to carry the cost, volume and technology risks associated with these decisions.

To be clear, we are not arguing that consumers do not benefit from these investments, but we do reject the notion that consumers are the sole beneficiaries.

Therefore, moving to some form of generator contribution is a highly desirable objective and would lead to a fairer outcome for consumers. Generator contribution to network assets will have the effect of exposing more of these costs to open markets and competition, which will drive better outcomes for consumers compared to a regulated environment that, despite good intentions to deliver a result that replicates a competitive market outcome, has not always proven to be so. Moving to some form of generator contribution will also place some of the long-term asset risk in the hands of those that are in the best position to manage these risks, being the generators and network operator.

We also believe that sharing risks and costs more equitably also leads to more equitable outcomes between consumers; currently specific consumers can take advantage of lower PPA prices while everyone pays for transmission. By allocating risks and costs to new entrant generators means they will absorb these costs and ultimately pass all or part through to the PPA purchaser.

We acknowledge the significant amount of work undertaken by the ESB in this area. We also acknowledge that many of our concerns are beginning to be reflected in proposed policy and regulatory approaches in this Consultation Paper. While we will always push for what we believe to be fairer outcomes for consumers, the ESB has moved some way towards achieving this.

We offer the following comments on issues raised in the Consultation Paper:

- So far we consider the actionable ISP rules including the Cost Benefit Analysis and Forecasting Best Practice Guidelines are providing a strong consumer focussed framework for the 2022 ISP; we would support a review of the Guidelines prior to commencement of work on the 2024 ISP to consider what changes might be needed to strengthen the Guidelines following the 2022 ISP experience
- We agree that the RIT-T process can take a long time to complete but from our observations the length of time taken is just as much to do with uncertainty of costs and benefits (at least for very large projects) than it is to do with the process itself. Therefore, we do not agree with the narrative that the RIT-T is somehow broken.
- Similarly, some have argued that the range of benefits that should be included in the RIT-T analysis should be expanded to include such things us local economic and employment benefits. We disagree with this view. If governments have specific goals (i.e. employment, environmental etc) then they should be responsible for delivering those goals and be transparent regarding costs and benefits and not try to use a RIT-T process to offload or obscure the cost of their policy via a regulatory process.
- While we would have liked to see the Interim REZ framework do more to allocate costs and risks more equitably we do acknowledge that it attempts to establish a level of coordination across jurisdictions and it does begin to require connecting generators to make a contribution towards deeper connection costs. These are positive initiatives that we support.
- On the issue of congestion management. We are pleased to see the ESB recognise that not only is a level of congestion inevitable but desirable as a goal of achieving zero congestion is an expensive and wasteful exercise. The ESB is also correct to point out that congestion sends important signals to market participants on where they should be seeking to connect.
- Finally, all too often congestion is seen as a problem that consumers should pay to resolve. We disagree with this view. Congestion is an issue for the generator (equity) to resolve in the first instance, recovering this cost via the competitive wholesale energy market.
- We note that the ESB has a long term view that Locational Marginal Pricing (LMP) and Firm Transmission Rights (FTR) is the long term solution to managing congestion. We are not as sure as the ESB on this point and remain unconvinced that consumers would be net better off under this proposed model.
- In addition, the LMP/FTR approach is a means to manage congestion risk; it does not solve actual congestion as only investment in transmission and/or storage will provide the long-term solution.

Regarding the medium term access reform options, we agree that Hybrid congestion management and connection fee model is a reasonable step forward.

Congestion management model

This model introduces two changes to the existing arrangements which work in tandem. It builds on work undertaken during earlier reviews, notably Optional Firm Access (Stage 1).

First, all scheduled and semi-scheduled generators would face a congestion management charge, calculated each dispatch interval on a $/MWh basis as the generator's marginal impact on the cost of intra-regional congestion in the dispatch interval. This removes incentives to 'disorderly bid' in the presence of congestion and so promotes dispatch efficiency and congestion management.

Second, all scheduled and semi-scheduled generators would receive a rebate, calculated each dispatch interval, funded from the collective revenue received from the congestion management charges. The size of the rebate is a function of generator availability, not dispatch quantity, meaning that generators do not have an incentive to bid in a disorderly fashion, as they do now.

The rebate, in combination with the congestion management charge, is designed to result in financial outcomes for market participants that broadly replicate the status quo arrangements. This reduces much of the cost and disruption associated with more fulsome access reform, such as the introduction of locational marginal pricing and financial transmission rights.

This approach appears to be simpler to implement and manage and has the benefit of not materially changing the market dispatch engine or unduly impacting existing contract arrangements.

Locational connection fee

This model would charge new generators connecting to the grid a connection fee. The connection fee can be calculated based on one of two options:

1. The net present value of the expected marginal cost of congestion caused by a generator connecting to the grid at a particular location, over a defined period.

2. The net present value of the efficient cost of transmission infrastructure required as a consequence of a generator connecting to a particular point on the transmission network.

The connection fee would be calculated before generation is built. This would be done to ensure that the estimated future cost of congestion will be reflected in the total cost of the project in the planning stage, therefore providing an incentive to build at locations to minimise the connection fee. The fee would be calculated administratively according to a guideline or formulation developed by AEMO. While the fee would be set and fixed at the time of connection, it could be recovered from the connecting party over time.

The fee would vary depending on the generator location because some areas of the network will have more capacity to host new generation capacity than others, and different expectations of other subsequent generation connections affecting flows on the network. This option could be designed to complement a REZ framework by exempting generators that participate in a REZ tender from the need to pay a connection fee.

The fee would vary over time, for a given location, depending on the network topology at the time of the fee calculation. By exposing new connecting generators to an estimate of the marginal cost of their decision on grid congestion, generators would face an incentive to locate in areas that will minimise their impact on congestion, in conjunction with other important factors influencing their location. Incumbent generators would not be subject to a connection fee, given that they are already connected to the grid.

We support the locational connection fee option as a good step forward. We would need to see how this fee is treated within the TNSP RAB so as to ensure the benefit flows back to consumers as a reduction in customer TUOS.

As for the longer term solution. We are not convinced that the LMP/FTR framework will deliver material benefits to consumers by way of lower costs or shared risks.

We continue to support further investigation of a generator TUOS model and hope this has not been dismissed as a future option.

Once again thank you for the opportunity to make this submission. We would also like to thank all those involved with the ESB and the Post 2025 reform process. Attempting to chart a course for the energy market in such a volatile environment is like trying to nail jelly to a wall whilst the wall is moving.

Kind regards,

Andrew Richards
Chief Executive Officer