26 July 2022

Anna Collyer
Independent Chair
Energy Security Board

Lodged by email: info@esb.org.au

Dear Ms. Collyer

Re: Capacity Mechanism High Level Design Paper

ACEN Australia (formerly UPC-ACEN),[1] is pleased to provide a response to the Energy Security Board (ESB)'s Capacity Mechanism High Level Design Paper.

ACEN Australia is a fully owned subsidiary of the AC Energy Corporation (ACEN). ACEN, headquartered in Manila, is one of the largest renewable energy companies in South-East Asia. The company has 2,600 MW of attributable capacity in the Philippines, Vietnam, Indonesia, India, and Australia. It currently has several GW of projects at various stages of development across the National Electricity Market (NEM), including in New South Wales, Victoria, South Australia, and Tasmania. For more on ACEN, visit www.acenergy.com.ph

To be clear, our preferred approach to ensuring reliable outcomes for consumers is not to have a capacity market, but rather rely on, or enhance, the scarcity price signals inherent in the National NEM's energy only market design, complemented by a liquid financial market. Introducing a capacity market will require a fundamental rewrite of the National Electricity Rules (NER) that will inevitably have material impacts on the existing spot and contract markets. This could undermine long term investment incentives, rather than enhance them as intended.

If a capacity market is to be adopted, then we consider this should be done in a way that is consistent with national and jurisdictional climate change objectives. Getting the detailed design elements right will matter greatly in this regard.

The Energy Security Board (ESB) has consulted on a range of different design options for a capacity market. We agree that a centralised model is likely the best way forward. A centralised capacity market strikes the right balance between giving governments' confidence over reliability outcomes and using a market based approach - auctions - to determine how those outcomes are achieved.

Energy Ministers have set out several principles to guide the design of a capacity mechanism, which includes the need for the design to be consistent with achievement of emissions reductions objectives. Achieving the latter will require careful attention to the detailed design elements of a capacity mechanism. An excessive weighting of reliability over emissions reductions outcomes will mean Australia's commitment to the Paris Agreement will be harder and more costly for consumers.

With this framing in mind, ACEN sets out its views below on the core capacity market design elements open for consultation.

[1] In 2017 ACEN acquired an 50% equity stake in UPC Renewables Australia Pty Ltd, headquartered in Tasmania and part of the global UPC Renewables Group that was established in the early 1990s. The UPC Renewables Group has developed, owned, and operated over 10,000 MW of large-scale wind and solar farms in 10 countries across Europe, North America, North Africa, China, Southeast Asia, and Australia, with an investment value of over $5 billion USD. In 2021 ACEN started the process to fully acquire UPC Renewables Australia Pty Ltd to form ACEN Australia.

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1. Eligibility to participate in the capacity market

The consultation paper proposes a technologically neutral approach to capacity market participation. In general we would strongly support this, as it ensures lower cost outcomes for consumers and encourages innovation in achieving the reliability objective, but in the current environment we do not consider this would be the right approach. Existing high carbon generation capacity would have an advantage over zero emissions technologies in the auctions, because its capacity is largely sunk and depreciated. If the long term objective of a capacity market is purely to ensure reliability, then the consequence of high carbon plant dominating capacity auctions would not matter. However, the principles set by Energy Ministers to guide the capacity market design explicitly require any such design to be consistent with achieving emissions reductions in line with decarbonisation goals set by governments both jurisdictionally and at a federal level.

The need to consider environmental objectives within the capacity market design has recently been recognised by the UK government. Because of concerns over the dominance of high emissions plant in capacity auctions to date, the Department of Business, Energy and Industrial Strategy (BEIS) has commenced consultation on the reforms necessary to ensure the capacity market in future is more aligned with achieving net zero emissions reduction targets.[2]

In framing its review, the BEIS notes that a future capacity market must appropriately weigh the potentially lower reliability costs of high carbon generation against the higher environmental costs of such generation.[3] We strongly agree with this view. To the extent the capacity market design encourages existing high carbon plant to operate longer than necessary or 'locks in' such plant through long term capacity agreements, this will make emissions reductions objectives harder and more costly to achieve in the long term. For this reason, our preference is for the capacity mechanism to incorporate an emissions limit of some form, one which is consistent with achieving Net Zero in line with our Paris Commitment.

ACEN acknowledges a zero emissions limit for participation in the capacity mechanism is unlikely to be acceptable from a reliability and cost perspective in the short term. A sensible balance between achieving reliability and emissions reductions would be to set an emissions limit that is ramped down over time - excluding no technology in the short term - but then gradually forcing out high carbon technologies, much like vehicle emissions standards put in place by the European Commission, for 2020, 2025 and 2030.[4] The downward trajectory for emissions limits would need to be in line with the federal government's 2030 and 2050 emissions reductions targets. This approach would provide for orderly exit of high carbon generation and keep costs manageable for consumers, while providing a long term signal for investment in zero emissions dispatchable technologies.[5] Existing higher carbon generation businesses would have time to adjust in line with evolving technology costs, for example by scheduling new investments and/or refurbishments over time (eg. converting CCGT to biomass or green hydrogen).[6]

An alternative, though possibly less attractive, approach to an explicit emissions limit applying across all technologies, is to split the auction, with a separate dedicated auction for zero emissions technologies while retaining the core auction for all other technology options.[7] Like with like technology competition would ensure an even playing field in the auction. Key issues with this approach however are working out the right split between technologies, the lower liquidity of smaller auctions, and by design, this approach could keep high carbon capacity in the market longer.[8]

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[2] Department for Business, Energy & Industrial Strategy, 'Capacity Market: Improving delivery assurance and early action to align with net zero – Call for Evidence', July 2021,

[3] Ibid p 34

[4] See https://ec.europa.eu/clima/eu-action/transport-emissions/road-transport-reducing-co2-emissions-vehicles/co2-emission-performance-standards-cars-and-vans_en

[5] This would be a more transparent approach compared to ESB's proposed orderly energy exit management contracts

[6] Department for Business, Energy & Industrial Strategy, 'Capacity Market: Improving delivery assurance and early action to align with net zero – Call for Evidence', July 2021, pg. 33-37.

[7] Ibid p 35

[8] The BEIS is however actively considering this as an option for the UK capacity market

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While an overall emissions limit, scaled down over time, is to be preferred, one context in which a separate dedicated auction could have real benefits, is for long duration energy storage (LDES). While there are a number of LDES technologies that are emerging, such as gravitational storage, redox flow batteries and hydrogen, pumped hydro is the most mature. However, the proposed T- 4 auction time frame will likely be too short on its own to encourage new investment in this technology. Given 6-to-7-year lead times for development and construction of new pumped hydro, the longer term capacity contracts would not be available at the start of construction. Pumped hydro and other forms of LDES are expected to play a crucial role in a future power system dominated by intermittent renewables and where extended periods of low supply due to coincident low wind and/or solar radiation will become more frequent.[9] A capacity auction further ahead of the delivery year (ie T- 6 or T- 7) would significantly strengthen incentives for investors and financiers to commit funds to LDES, by making longer term contracts available to LDES prior to construction. BEIS is currently consulting on what changes could be made to the UK's capacity market design to support LDES, with longer auction time frames a key area of focus.[10]

2. Duration of capacity contracts

ACEN supports ESB's proposal for 1 year capacity contracts for existing technologies, consistent with the length of the capacity delivery year. This aligns with international practice and recognises that existing technologies have already made their investment decision and their capital costs are sunk and partly or wholly paid off in many cases. 1 year contracts provide a reasonable balance between providing incentives for existing capacity to remain in the market and contribute to reliability if it efficient to do so, while avoiding the risk of locking in high costs (including environmental costs) over longer time frames, particularly for high carbon technologies.

In contrast, multi-year contracts are needed to support investment and financing of new build zero emissions dispatchable capacity, such as pumped hydro or other forms of LDES, because of their high up front capital costs and uncertainties around future revenue streams in the spot market (which creates unpredictability around cost recovery for projects). Creating a predictable and stable revenue stream for a significant portion of the costs over a reasonable time frame will substantially increase the bankability of such projects.

The British and Italian capacity markets allow for 15-year contracts for new build capacity. We consider this is about the right timeframe for most technologies, excepting those technologies with very high upfront costs and long asset lives, such as pumped hydro or hydrogen (once it becomes economic), which would benefit from even longer contracts of up to 40 years to match their asset lives.[11] We also note the NSW Government is offering up to 40 year Long Term Energy Services Agreements (LTESAs) for long duration storage as part of its Electricity Strategy.[12]

In ACEN's view, longer term contracts (ie those longer than 1 year) should only be available to new build zero emissions dispatchable capacity, to avoid locking in high carbon generation over multiple years and making future emissions reductions more costly to deliver. In this respect it is worth noting that AEMO's 2022 Integrated System Plan indicates that no new investment in emissions intensive generation is needed to meet future reliability, instead forecasting that a combination of grid scale storage, coordinated behind the meter battery storage and hydro will be built to maintain future supply reliability while meeting carbon reduction objectives out to 2050.[13] It is important that long term capacity market contracts do not act to distort this pathway.

3. Defining firm capacity

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[9] AEMO, 2022 Integrated System Plan for the National Electricity Market, pp 54 to 57

[10] , Department for Business, Energy & Industrial Strategy, "Facilitating the deployment of large scale and long duration storage: call for evidence", p 16

[11] Ibid p 21

[12] NSW Government, Long Term Energy Service Agreement Design, Consultation Paper, August 2021

[13] AEMO, 2022 Integrated System Plan for the National Electricity Market, pp 55-57

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Having a sound derating methodology in place is one of the most critical elements of a capacity market design so that capacity is fairly compensated for the value they deliver during at risk periods.

In principle, ACEN would support a simple, transparent, and replicable methodology, that allows for stability in deratings over time. Such methodologies are based on estimates of capacity factors during designated peak periods, with a focus on backward looking historical outcomes to forecast future outcomes.[14] We agree with the ESB however, that a backward looking approach basing on historical performance during specific time periods risks inaccuracy as the timing of at risk periods changes over time due to a changing mix of technologies - shifting to different times of the day as well as different seasons.[15] Best practice internationally is moving toward more forward looking probabilistic simulation modelling that better capture changes market system dynamics as the penetration of renewables increases. We understand AEMO's preference is for the Effective Load Carrying Capacity (ELCC) approach, used in North American markets and currently being considered for implementation in the WEM.[16]

The ELCC of a capacity provider is a measurement of that provider's expected contribution to reliability when the power system is most likely to experience unserved energy, taking the likely contribution of all other system resources into account at the same time. In this respect the ELCC would provide a natural extension of the probabilistic modelling AEMO performs currently in calculating the expected unserved energy in its reliability assessments.

An important strength of the ELCC method is that it can capture the portfolio benefits of complementary zero emissions technologies for reliability, such as solar plus storage, where the ELCC for the combined resource and its subsequent derating would be greater than the ELCC and derating for each technology individually.[17] The PJM Regional Transmission Operator has calculated binding ELCC derating factors of 83% and 84% respectively for capacity years 2023/24 for combined solar and storage (of 4 hrs duration), almost matching that of conventional generation.[18]

We consider that if ELCC is implemented in a way that recognises these synergistic effects, it could provide means for renewable energy participants to realise significant value synergies in the capacity market from investing in complementary zero emissions technologies. This would help support the investment in zero emissions technologies required to meet ambitious climate change objectives while maintaining a reliable power system.

4. Defining at risk periods

The definition of at-risk periods is closely linked to the choice of derating methodology. Consistent with our comments above, while we consider there would be benefits in terms of transparency and predictability for capacity providers in adopting a simplified approach, based on predefining discrete at-risk time frames, this would be unlikely to reflect reality of a changing power system. A probabilistic scenario-based approach to forecasting/modelling at risk events, such as that embodied in AEMO's Lack of Reserves (LOR) framework, is likely to lead to better outcomes and would better complement probabilistic derating methodologies such as ELCC.

5. Performance obligations for capacity delivery

ACEN is supportive of the ESB's preferred performance regime, specifically the concept of a two-part capacity payment to ensure performance. This is because LOR framework provides short term notice on the size and timing of reserve shortfalls, this does not provide certainty over future revenue streams capacity resources may require ahead of time to support investment. For this reason, a two-part capacity payment with one part linked to availability throughout the delivery year and the other to

[14] For a good description see, Lu, Shuai; Diao, Ruisheng; Samaan, Nader A. & Etingov, Pavel V. Capacity Value of PV and Wind Generation, prepared for the US Department of Energy, September 2012
[15] AEMO, 2022 Integrated System Plan for the National Electricity Market, Appendix 4, pp 13 to 16
[16] Energy Transformation Taskforce, Storage Participation in the Reserve Capacity Mechanism, June 2020
[17] Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company's ELCC Study Submission
[18] PJM RTO Effective Load Carrying Capability (ELCC) report July 1, 2021

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availability during low reserve conditions provides a reasonable balance between future revenue certainty (provided by the first part payment) and system needs (reflected by the second part payment).

That said, we do not consider that withholding capacity payments should occur in circumstances where unavailability is beyond the reasonable control of the capacity provider. Specifically, intermittent resources should not be penalised for being unavailable due to changes in weather given they cannot, unlike carbon intensive generation, control their primary fuel source.

This requires a careful definition of what constitutes 'availability' for intermittent renewables. We consider the right metric for intermittent renewables is 'plant availability' as defined in clause 3.7B of the National Electricity Rules (NER), which is required to be provided as part of a semi-scheduled generator's information inputs into the Unconstrained intermittent generation forecast (UIGF). Plant availability is defined here as, "active power capability of a unit assuming no limitations on fuel availability." Using this availably metric would allow renewables to effectively participate in a capacity market and contribute to reliability without introducing uncontrollable compliance risks.

Finally, it is important that if no LOR events occur during the delivery year that capacity providers still receive the second part of their capacity payment (assuming they have met the general availability conditions), which reflects the insurance value of the capacity product. A capacity market, if it works well, should lessen the frequency of actual LOR events. Withholding capacity payments from providers because reliability objectives are successfully delivered by them would appear a perverse outcome and could dissuade potential capacity providers from participating in the first place.

6. Reducing the Market Price Cap

The consultation paper notes there may also be a need to recalibrate the existing reliability settings (such as the market price cap) to prevent generators (or demand response providers) being paid twice for their capacity. We strongly disagree with this view. Considering capacity resource providers being able to recover their fixed cost in the capacity market, a competitive wholesale market should encourage these same providers to offer their capacity at marginal cost, which should naturally act to reduce the level and volatility of wholesale market prices.

Keeping a high MPC would in fact be complementary to the longer-term signals provided by the capacity market, as it would continue to provide short term price signals for flexible capacity in a future power system dominated by renewables. AEMO's most recent ISP forecasts fundamental changes in the structure of the demand curve over the next decade, which will require increasing volumes of fast ramping capability to meet larger, faster and more frequent residual demand swings over time, both positive and negative.[19] AEMO further notes these demand swings will become difficult to forecast given the weather dependency of so much of the supply resources in the future power system, requiring sharp operational price signals to encourage the necessary fast ramping capability to respond at short notice.[20] The prospect of potentially high operational revenues from the spot market over and above capacity payments will be necessary to incentivise these technologies.

7. Other market design issues

The consultation paper raises the question of whether capacity resources in one region should be recognised in another region and proposes two alternative methodologies for how this could be achieved:

- capacity requirements in each region would be adjusted to reflect expected interconnector flows during periods of system stress, so the inter-regional resources would be recognised, but not procured or paid for; or
- Capacity providers located in one region would be eligible to sell capacity to meet reliability in another region (i.e., eligible for procurement).

[19] AEMO, 2022 Integrated System Plan for the National Electricity Market, Appendix 4, p13 to 16

[20] For a good discussion on this see also AEMC Directions Paper, Reserve Services in the National Electricity Market, 5 January 2021 p 29-31

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While acknowledging it would be a more complex approach, we strongly advocate for option 2, which would allow capacity providers to receive an inter-regional capacity contract. ACEN notes that jurisdictions such as Tasmania and South Australia, which have significant medium and deep storage capacity, but low populations, should be given the opportunity to maximise the value of that capacity by being recognised for the reliability contributions they can provide to neighbouring jurisdictions. Such value will become realisable once Marinus Link and Project Energy Connect are built.

We recognise this will be complex to implement. ACEN considers this will likely require assignment of transmission transfer rights across interconnectors to capacity market providers, to avoid or minimise the risk of capacity value of existing providers being diminished through new entry. By linking access to capacity revenues to interconnector transfer rights this would avoid new entrant capacity providers simply displacing the capacity value contribution of existing players with no net gain to reliability. This approach would be consistent with the concept of Network Access Quantity (NAQ) recently implemented in the WEM to deal with intraregional network constraints.[21]

6. Conclusion

Our preference is not to have a capacity market. However, as we have set out above, if one is to be adopted, then we consider this can be done in a way that is consistent with emissions reduction objectives and minimises distortions in the existing energy only market, by doing the following:

- implementing an emissions limit that ramps down over time;
- introducing multi-year contracts for new build capacity and allowing only zero emissions new build capacity to have access to such contracts;
- having a separate auction for LDES with a T-7 year time frame;
- implementing a derating methodology that captures potential synergies of complementary zero emissions technologies such as solar and storage; and
- retaining the current approach to setting the MPC.

If you would like to discuss any of the comments in this submission further, then please contact Con Van Kemenade at con.vankemenade@upc-ac.com or phone: 0439399943.

Sincerely,

Dr Michael Connarty
Head of Strategy and Stakeholder Engagement
ACEN Australia

[21] Energy Transformation Taskforce, Reserve Capacity Mechanism, Changes to support the implementation of constrained access and facilitate storage participation, May 2021

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