Shell ENERGY

25 July 2022

Anna Collyer
Chair
Energy Security Board

Dear Ms Collyer

RE: Capacity mechanism high-level design

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Energy Security Board's (ESB) capacity mechanism high-level design paper.

About Shell Energy in Australia

Shell Energy is Shell's renewables and energy solutions business in Australia, helping its customers to decarbonise and reduce their environmental footprint.

Shell Energy delivers business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers, while our residential energy retailing business Powershop, acquired in 2022, serves more than 185,000 households and small business customers in Australia.

As the second largest electricity provider to commercial and industrial businesses in Australia[1], Shell Energy offers integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. The company's generation assets include 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and the 120 megawatt Gangarri solar energy development in Queensland.

Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy, while Powershop Australia Pty Ltd trades as Powershop. Further information about Shell Energy and our operations can be found on our website here.

General comments

The ESB has proposed a centralised capacity mechanism under which all existing and new capacity will be eligible to bid for capacity payments. We recognise the ESB's stated preference for a capacity mechanism that rewards both existing and new capacity in the scheme. We also note that Energy Ministers have requested the ability to be able to opt-in or opt-out of the mechanism and determine eligibility for certain technologies.

In our view, the design of a capacity mechanism should:

- Incentivise the build of new generation to support reliability;

[1] By load, based on Shell Energy analysis of publicly available data.
[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2021.

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- Minimise costs to consumers;
- Minimise implementation complexity;
- Minimise the impact on existing market signals and contract market liquidity; and
- Support emissions reduction objectives.

Shell Energy supports the intent of the ESB's capacity mechanism work, but we believe an alternative model will better deliver the outcomes it is seeking to achieve, at a lower cost to consumers. Shell Energy previously raised a New Entrant Reliability Mechanism model with the ESB similar to the Irish market's reliability options model.

We proposed that a central buyer would procure sufficient new capacity through cap contracts to address any forecast reliability shortfalls in the market. New capacity would have to be built in order to participate in an auction. We maintain that this option could meet the ESB's assessment criteria along with the Energy Ministers' principles in a more straight-forward fashion than the ESB's proposed approach. We believe a New Entrant Reliability Mechanism would appropriately manage the risks of disorderly exit and reliability at a lower cost to consumers than the ESB's proposed model. In part, this is because details on issues such as derating and compliance are effectively self-solving by those bidding in to provide the reliability options. It would also avoid changes to the existing market settings, and by extension, a negative impact on contracts market.

The ESB's current proposal is not without risks. Some design choices could advantage incumbent thermal generators and keep them operating longer than they may otherwise under the current market design. This will delay the decarbonisation of the electricity sector. In addition, conservative derating approaches could disadvantage other technologies such as battery storage or demand response by under-rewarding it relative to other technologies.

Our main concern relates to the impacts of allowing jurisdictions to set their own criteria for participation in capacity auctions. Such an approach could fragment the NEM and may result in the disorderly exit of existing generators – the very issue the ESB is seeking to avoid.

Shell Energy strongly advocates for consistent market settings and signals across states. Herein lies one of the challenges with state-based approaches to eligibility. As noted in the design paper, if a capacity market is introduced, the market price cap (MPC) may need to be reduced in order to avoid consumers paying twice for reliability. The NEM's current MPC of $15,500 is high because in effect, it pays for capacity to be available at critical times. It also provides a very strong real-time signal for the delivery of energy. With a capacity mechanism in place, a high MPC may not be necessary as generators receive payments for capacity from a separate market. However, the real-time signal for delivering energy may be greatly reduced. Whether or not this would truly deliver lower costs to consumers is as yet untested.

A challenge will then arise if states set different eligibility criteria meaning that a common MPC across different states may be impossible. If one state excludes certain technologies, then a higher MPC may be needed to ensure these generators can recover their long-run costs and avoid a disorderly exit from the market. From a market perspective, different MPCs in different states would almost be unworkable. For instance, how would energy flow efficiently between states if one region was at its lower price cap and a neighbouring state was at a higher price but below its MPC? It is difficult to see how the contracts market, which allows for risk management and the efficient pricing of retail contracts, can function smoothly where there may be different price caps in different regions. The high energy MPC is also tied to the frequency control ancillary services markets which held keep the grid secure. A lower MPC may reduce the incentives for batteries and other technologies enter these markets and provide these kinds of essential system services.

The costs of change

A move from the existing market settings to a capacity market represents a major and complex change. The changes associated with introducing a capacity market will require deep investment in system changes for both the Australian Energy Market Operator (AEMO) as well as market participants. Shell Energy considers there needs to be a greater focus placed on the costs of the various reforms in train – not just the capacity mechanism –and whether the benefits will exceed the substantial costs being incurred.

The energy market as a whole is already facing significant cost and resource pressures as a result of the constant and complex regulatory changes that have taken place over the past few years. AEMO's fees for 2022-23 have increased by 48 per cent compared to the year before[3] and AEMO has estimated the costs of the NEM 2025 Reform Program at $250-330 million excluding a capacity mechanism, transmission reform and ongoing costs.[4] Collectively, participant costs are likely to exceed AEMO's costs several times over. These costs flow through to consumer bills and as such clear benefits must be demonstrated before embarking on such a major, transformative reform as a capacity mechanism could be.

Shell Energy would like to see the ESB present detailed analysis to demonstrate whether a capacity mechanism will deliver lower overall costs to consumers compared to the existing energy-only market. Any analysis should also include the implementation costs which we consider are likely to be significant on both AEMO and market participants. Ultimately, customers will bear the risks of poor design choices in the form of higher costs and may see little meaningful improvement to reliability.

The submission that follows provides answers to the ESB's detailed question on the design of the capacity mechanism. For more detail on our submission, please contact Ben Pryor, Regulatory Affairs Policy Adviser (0437 305 547 or ben.pryor@shellenergy.com.au).

Yours sincerely

Greg Joiner
CEO, Shell Energy Australia

[3] AEMO, 2022-23 Budget and Fees.

[4] AEMO, Declared NEM Project – NEM 2025 Reform Program Consultation Paper, p 3.

Forecasting demand and the building blocks for a mechanism

Do you agree that the capacity mechanism should provide for multiple zones being the existing NEM regions?

Shell Energy agrees that the capacity mechanism should use the existing NEM regions for capacity purposes. There is no reason to depart from the NEM's existing structure in this regard.

Is there sufficient evidence to say that the at-risk periods can be defined on a time-based definition? If there is a risk of the emergence of more than one at-risk period in the NEM how should that be addressed?

The ESB sets out a range of potential approaches towards at-risk periods, which would have a flow-on effect to derating electricity generators. Shell Energy considers that a probabilistic assessment of the most likely times of tight supply-demand balance would be the most appropriate solution based on what the ESB has set out. While the summer period currently appears to have the highest theoretical risks of reliability shortfalls under extreme demand conditions combined with high unplanned generator outages, the combination of high demand and low VRE output combined with planned outages during other periods could create additional windows where reliability may be at risk.

That said, Shell Energy remains unconvinced by the need for designated at-risk periods and the role they play in a capacity mechanism. We recognise it can play a role to certain generators that they should be prepared to be available at these times by having fuel or charge available – generators like BESS, demand response, gas and run of river and pumped hydro. While the broad at-risk period would appear clear to most participants in the market – early evening on summer weekdays when demand peaks – in reality true at-risk periods may appear at any time. As we have observed recently, a combination of events such as unplanned generator outages alongside planned outages, low VRE output and high demand can put severe strain on the grid. Attempting to predict these kinds of events in advance with a required level of accuracy is virtually impossible.

This kind of situation is one of the key drivers behind our New Entrant Reliability Mechanism approach where new scheduled capacity is built via a centralised auction for cap contracts. This mechanism would place the onus on the generator providing the cap contracts to be available at critical times of the year, whenever this occurs.

The de-rating factors produced by different at-risk period definitions and modelling methodologies can show large ranges particularly for non-traditional technologies. How should this and potential year to year variability in de-rating factors be addressed? What approaches should be used to de-rate different technologies? Should different approaches apply to different technologies? What is the right balance between transparency/simplicity and accuracy? Should de-rating factors be determined at a technology class/region level or at a station level?

There is a large difference between generation technologies of different types and as such different approaches will be needed to assess de-rating factors. For thermal generators, there is a large degree of history to draw from. Stochastic modelling can be used to provide a sound estimate of the expected output of these kinds of generators.

For technologies with less of a historical output to draw from such as battery storage and VRE, derating will be more of a complex arrangement. For VRE, the NSW Government has adopted an approach for its Energy Security Target where the 10th percentile output from solar and wind output during a sample of NSW peak demand periods from the previous three summers is used. This may represent a possible option for the ESB's capacity mechanism.

As for battery storage, we have concerns with the concept of linear derating resulting in say, a battery with two-hours of storage being derated by 50 per cent if the at-risk period is four hours. We consider this will significantly under-value the flexibility and optionality that battery storage can provide. Even in a four-hour at-risk period, there is likely to be a smaller window within that when demand peaks and supply is most critical. A broad-brush approach like linear derating will likely result in a need for more capacity than is otherwise necessary, increasing costs to end users.

Finally, in the case of demand response we note that AEMO's RERT can provide guidance to the ESB. As per the RERT Panel Agreement, AEMO does not require the precise volume a contract to be delivered at all times. Rather, AEMO sets a performance capability of "at least 80% of the quantity of reserve specified in the reserve contract during each 30-minute period covered".[5] From our perspective this represents a reasonable approach that both ensures sufficient volumes are delivered without imposing too stringent requirements that would create a barrier to entry.

In addition to these technology specific comments, Shell Energy suggests that at a minimum, station-level derating factors are applied. Given the relatively small number of generating facilities, we do not believe it will be too onerous to develop and will provide more accurate figured than broader approaches such as region-wide or technology type.

The complexity involved in setting these derating factors is yet another reason why Shell Energy continues to advocate for our New Entrant Reliability Mechanism. Under our model, it would be up to the generator to determine their own derating factor and generate accordingly at times of high prices. We contend that generators are better placed to both assess the capability of their plant and operate accordingly than the system operator. Generators who are unable to deliver sufficient capacity at times of high prices would be exposed to the spot price outcome meaning that they are strongly incentivised to accurately forecast their expected availability at times of high prices.

Do you agree with the approach to setting the forecast capacity requirement and the target capacity in a region?

How should the target capacity be determined where there are gaps in more than one region?

In the event that the ESOO shows a gap in multiple regions, Shell Energy considers that AEMO should adopt an approach where capacity from adjoining regions can be used to support the need for capacity in other states. This will form an important part of minimising costs to consumers. The NEM is an interconnected system where due to the observed temporal diversity in timing of maximum peak demand, supply from one state can contribute to meeting demand in another, so it is only logical to extend this to the provision of capacity as part of a capacity mechanism.

The RERT offers an example of how this can be achieved. Section 5.2 of AEMO's Procedures for the exercise of the RERT outlines a methodology where excess reserves in one state can be used to address shortfalls in other states where transmission capability allows for this. Indeed, AEMO's procedures highlight that there could be multiple solutions to addressing shortfalls in different regions. Further, when dispatching RERT, AEMO must have regard to the relative costs and features of the proposed reserve to determine the most effective portfolio pf reserves to be contracted. Shell Energy believes this represents an important design principle for a capacity mechanism: that the total costs and quality of reserves must be considered. For example, it may be more economic for capacity in Region A to be procured to meet a shortfall in Region B, or vice versa.

[5] AEMO, RERT Panel Agreement 2021-22, p 30.

Procuring capacity and auction design

Should retailers have a role in a centralised capacity mechanism? If you support retailer involvement in procurement, what are your views on how this could operate?

Shell Energy does not consider there is a need or justification to have retailers participating directly in the procurement of capacity as part of the mechanism. We do not see how there could be any benefit to consumers if both retailers and AEMO were competing for capacity in auctions. In the first instance, there is a mismatch in timing of different retailers' peak demands and the system peak for each region meaning there would be an increased need for capacity and therefore, higher costs to consumers. Retailers' demand will peak at different times of day so the sum of each retailers' peak demand will exceed the total maximum demand that the system experiences. A single buyer in AEMO procuring for the system peak in each region will be lower than multiple retailers each having to procure for their own peak demand. Retailers may also include a risk buffer meaning that the total capacity procured would be even higher. This may lead to there being sufficient capacity, but consumers would face these additional costs.

Indeed, having rejected the concept of a physical Retailer Reliability Obligation (PRRO) a model that would then require retailers to purchase capacity certificates, would be strikingly similar to a PRRO in practice. Shell Energy recognises the ESB can see benefits in retailers providing demand forecasts for the purposes of the capacity mechanism. However, it is important that the ESB understand that retailers forecast customer demand not as a means to perfectly assess demand over the course of a day or a year, but as a tool to manage spot market price risks. Overall, we consider that the current top-down centralised approach for forecasting regional maximum demands, whilst not without some flaws, remains the best process for the assessment of the level of required capacity to achieve the reliability standard.

Do you agree with holding two auctions for each delivery year and is this timing appropriate? If no, what auction frequency and timing is appropriate and why? How should the timing of the auctions align with the notice of closure obligation?

Shell Energy considers the proposed approach of longer-term and shorter-term auctions to be a reasonable approach. The specific number of years ahead may need to be different to the four and one year ahead auctions the ESB has used as a placeholder. Auctions in advance of four years may be necessary to facilitate entry of new projects.

We agree with the view that the notice of closure timing can be linked to auction timing. If the rule change request to increase to notice of closure to five years is made,[6] then it would be logical to align the timing of the longer-term auction to the new notice of closure timing. Importantly, we do not feel there is a need to limit auctions to just these timeframes.

Using auctions over a range of timeframes will provide a degree of flexibility to AEMO to manage changes in demand forecasts over time. Auctions at T-4 (or further in advance) could be used to secure new capacity over a long-term basis, and to lock in existing capacity for a period of time. Future auctions over the proceeding years could then continue to build a 'stack' of capacity for the delivery year. As the capacity delivery year approaches, AEMO would then have the scope to procure capacity on a shorter-term basis solely for the delivery year. Technology such as demand response may be ideal for this kind of short-term, year-in-advance contract.

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[6] AEMC, Amending generator notice of closure arrangements, rule change proposal

We also contend that there is a need to align the notice of closure requirement with other aspects of auction design. For instance, we do not believe it would be good policy to allow generator to bid for capacity certificates beyond their listed notice of closure date. Nor do we believe that notice of closure dates should be pushed out further in order to receive capacity credits unless there is a compelling system need for this to occur. If an orderly transition is to occur, then we consider that generators should exit when they have committed to do so to give clear signals to investors as to when new capacity is needed in the market.

In relation to the proposal for two auctions per year, this may be suitable depending on how costs are passed on to consumers. If costs are passed on in a lumpy fashion, with charges occurring at specific times of the year – immediately after each auction for instance – then this will change the dynamics for commercial and industrial (C&I) retail contracting. It would likely create a scenario where there are limited windows for C&I customers to contract during the year as retailers will need to ensure that costs can be recovered. However, if costs are allocated to retailers on a smoothed basis, such as a $/MWh charge over the course of a year, then it will allow customers to contract at any point in the year, as they do now.

This leads to another point of giving confidence to market customers that costs can be passed through to end users. We consider that capacity mechanism costs should be allocated on a prospective basis rather than retrospectively. Customers change retailers throughout the year and retailers need to be confident that costs can be passed on. A methodology that flows through AEMO's existing settlements process as a separate and transparent charge would be preferable. This would also allow the costs to be considered by regulators when setting default prices for households like the Default Market Offer (DMO) or the Victorian Default Offer (VDO).

We also consider that there may be ways to leverage the existing process for allocating RERT costs. Currently, RERT dispatch and pre-activation costs are allocated based on consumption during the periods in which RERT was activated. It may be possible to do the same for capacity payments related to generator performance and market customer consumption during LOR2 or LOR3 periods when supply is most critical. In line with our previous comments, we see that this should be on a $/MWh basis to ensure that costs can be passed on transparently.

What are your views on how existing and new capacity should be treated in the auction process?

Are there other considerations the ESB should take into account for the detailed design?

Do stakeholders have a view on the optimal duration of certificates or price certainty for new capacity?

Do stakeholders have a preference as to whether the investment support scheme provides guarantees of price only, or of both price and quantity?

We agree with the design paper's assessment that demand response may not be well suited to making longer term commitments if auctions are held up to four years in advance and DR providers may prefer to commit nearer to time, at T-1 say. Shell Energy adds that while DR providers may prefer to wait until T-1 to commit to making capacity available, they are likely to want to commit to multi-year contracts for capacity. Multi-year capacity contracts would help to provide revenue certainty which can assist in addressing the upfront costs which DR involves. Customers with DR may need to invest in a range of items to allow for firmer demand response capabilities such as onsite systems and processes, metering, wiring, and hardware and software solutions. Multi-year contracts can also help to align capacity contracts with C&I retail contracts.

We consider that a capacity mechanism may help to bring some DR from out-of-market, where it currently forms part of the RERT, to in-market. This would be of broader benefit to consumers as a whole. By allowing more flexible rules than the RERT currently allows, there could be advantages to retailers or demand response service providers in bringing DR into the market. At present, under the RERT, customers that have chosen to participate are locked into the contracted party's agreement meaning that if any customers choose not to participate, they cannot be replaced. A capacity agreement should with a DR provider should allow for customers to be brought into and out of an arrangement naturally, without having to rework a contract for capacity between the provider and AEMO. Similarly, the RERT provides no reward if a DR provider can deliver more than the contracted quantity of demand response. While this makes a degree of sense in the context of RERT, in the context of a capacity mechanism, the ability to over-deliver capacity, particularly at times of system stress needs to be adequately recognised.

The ESB asks for comments on the duration of contracts for both new and existing capacity. Longer-term contracts will be an important tool to help support the entry of new capacity into the market. This may need to be in the range of 7-10 years to provide enough revenue certainty to underpin investments. Existing technologies may still require contracts of several years to provide revenue certainty to allow for planning of maintenance and fuel procurement. We consider that a maximum timeframe aligned with the notice of closure obligation would be a sensible approach, i.e. with the notice of closure obligation currently set at 42 months, the maximum contract an existing generator could be able to receive is for 42 months. This would also ensure that the entire MTPASA period could be covered by a capacity contract.

Shell Energy notes that the ESB proposes that capacity providers would participate in capacity auctions on a unit-by-unit basis. Shell Energy considers that this approach may have several detrimental effects which may result in higher costs to end users and limit the scope for innovation in the generation sector. A unit-by-unit approach may mean that generators do not make available the same volumes of capacity that they would under a multi-generating unit station or even regional portfolio basis.

In effect, each unit would only be as valuable as its minimum availability. Similarly, each unit that underperforms relative to its capacity sold would have to pay back any capacity payments related to its underperformance. When considered as a collective, a multi-generating unit station of regional portfolio may be more valuable than the sum of its parts, as a shortfall from one unit could be made up for by another unit. Currently, generators act in a similar manner in the contracts market. A hypothetical generator with four units may sell contracts equivalent to 75 per cent of its capacity, or three units. The remaining unit is effectively self-insurance against outages, so that if one unit is unavailable it can adjust output from its remaining units to make up for the shortfall.

On a related note, the ESB's proposed approach could reduce the incentive for variable renewable energy to self-firm their output in order to increase the capacity it is able to make available. Based on our interpretation of the ESB's proposed approach, a wind generator would receive one derating factor and a BESS would receive a separate factor. When combined the two units may be able to work together so that the battery takes over to 'firm' up the capacity of the wind generator. The combination of the two facilities might then be able to offer a greater degree of firmed capacity available than the high-level design would seem to allow. These facilities do not need to be co-located to provide a firmed response.

Shell Energy considers that the ESB should allow for generators to make capacity available on a portfolio basis in each region. This would place more of the onus (and risk) on the generator to ensure that there is sufficient capacity available across its fleet of generation in a region rather than for each individual unit. It would also create value for generators to firm VRE supply to deliver a more reliable supply of energy (and capacity). We acknowledge that a portfolio approach may create more complexity for AEMO to verify performance and availability against the volume of capacity certificates awarded. We also recognise that this would make it more challenging to separate contracts for new and existing technologies if this were to be a requirement. However, if capacity is accredited on a portfolio basis, changes in generating unit configurations within the portfolio over time could be adjusted.

Yet again, we consider that our proposed New Entrant Reliability Mechanism can avoid some of the complexities of a portfolio-based approach as it will be the responsibility of the seller to assess the potential output of any new portfolio of technologies. Additionally, as this model applies only to new capacity, it would limit the breadth of compliance checks necessary to ensure the mechanism is operating as planned.

In terms of whether auctions should provide a fixed capacity price and volume for the duration of the contract or solely a fixed price with capacity providers having to re-apply each year. Shell Energy considers that in order to provide investment certainty, particularly for new projects, both a fixed price and volume is required.

Internationally, capacity mechanisms rely on some multiple of the net-cost of new entry (net-CONE) assessment to determine the capacity mechanism market price cap. Is this appropriate or should an alternative approach be used?

How should the price settings interact with the energy market price? Over time, when settings are regularly reviewed, should the price settings in the capacity auction and the energy market be jointly determined?

Are there other considerations the ESB should take into account when determining demand curves in the detailed design?

Similar to the current process for the review of the reliability standard and settings, Shell Energy considers that any capacity market price cap should also look at established metrics such as the value of customer reliability (VCR). The VCR feeds into analysis underpinning existing market settings such as the market price cap and so should also form part of the analysis of a capacity market price cap. This should help to ensure that customers are not required to pay more than they are willing to for the provision of capacity.

While the RRO requires mandatory participation for the largest three participants in a region, the ESB considers a methodology for determining market power should be applied to account for changing market concentration over time. Are there specific market concentration thresholds of concern?

Should market power mitigation measures be applied to capacity providers with large market shares in supply-side regardless of their market share in retail?

Shell Energy supports the inclusion of effective market power mitigation measures for suppliers of capacity certificates as part of a capacity mechanism design irrespective of the participant's retail market share. As long as there is no requirement for retailers to directly procure capacity then a generator's retail market share is irrelevant to market power.

We would however caution the direct adoption of the current RRO requirements in this area as we consider them to be ineffective in meeting the requirements of retailers as opposed to the larger gentailers.

Do stakeholders support the proposal to integrate capacity mechanism settlement with the existing NEM settlement process? If not, what alternative process would better meet the design objectives?

As noted previously, Shell Energy supports the use of the existing settlements process to allocate costs to market customers. By extension this would involve integrating payments to capacity providers with the existing NEM settlements mechanism. We reiterate that costs should be allocated on a smooth and predictable basis to support customer contracting, particularly for C&I customers.

Obligations on capacity providers

Do you have preliminary views on compliance obligations for capacity providers?

Do you have views on compliance obligations for new entrant capacity in advance of the delivery year?

Do you support the ESB's proposed performance model for consultation? If no, what other proposed model would be better and why?

The ESB has identified three options for performance obligations on generators receiving capacity payments and indicates it favours a model where payments would be awarded in two parts: for being available throughout the year and a second payment for being available during periods of system stress. Shell Energy notes several challenges with the ESB's proposed approach. We are concerned that the level at which the two portions of the payment are set will have an impact on the incentives involved. A high proportion of the total capacity payment being made available for general availability could lead to higher overall costs for consumers. Conversely, a model that places too much reward for availability during LOR2 or LOR3 events may not deliver a sufficient incentive for year-round availability.

Shell Energy also wishes to comment on the ESB's references to availability in the context of performance obligations. In the design paper, the ESB states "some instances may occur where a capacity provider is bid-available in response to a LOR2 event but is not called upon for dispatch"[7] and that the ESB consider self-reporting of these instances could foster a culture of compliance with the mechanism. We struggle to see the benefits that this approach would deliver. In an LOR2 event there will be always be some level of generation that is not dispatched. A generator that is bid available has capacity that is able to be dispatched, but is not required to meet actual consumer demand. Similarly, even during a LOR3 event, i.e., a period of involuntary load shedding, there will be a mismatch between load requested to be shed and load actually shed such that not all available generation is always dispatched. The capacity mechanism appears to be designed to ensure that there is capacity available to be dispatched, rather than to reward the actual energy dispatched in a trading interval. That is the purpose of the energy markets settlement process where actual energy provision is rewarded. As such, we query the purpose of instituting a self-reporting mechanism when energy is available but not dispatched.

On a similar topic, when discussing the interaction of performance obligations and network constraints, the ESB claims "market participants may be unable to be dispatched and therefore unable to bid available if there's network outages out of their control."[8] This is only true if the network issue is on the generator's side of the connection point. A constraint on the shared network will have no impact on a generator's ability to bid available. While they may be bid available, the NEMDE may not be able to dispatch a generator to its full extent but it could still be available to generate to full capacity should the constraint be resolved. Again, we fail to see the relevance of this issue in the context of a performance obligation. In the event of a network constraint a generator is likely to have done everything within its ability to allow for it to be dispatched. Again, if the aim of a capacity mechanism is to reward the level of capacity available to be dispatched, how much energy is dispatched in a given trading interval is irrelevant.

We note that the ESB's design paper assessed a compliance model based on exposure to prices above $300/MWh, where failure to deliver energy at key times resulted in exposure to the spot price, would function. When assessed against the ESB's model of both existing and new capacity as eligible, the ESB determined it would not function in part because of the impact on contracts market. We agree with the ESB on this point when a model where all capacity is eligible. However, under a model where only new capacity is eligible, such as our proposed New Entrant Reliability Mechanism, the weaknesses of this compliance approach are limited.

Do you support the ESB considering capacity payments based on availability throughout the year and during periods of system stress?

If you support payments based on two factors, what is the preferred distribution of the first and second payment? Should more or less weight be given to responding to events?

To support revenue smoothing, should the ESB consider grouping events within the delivery year? If yes, what frequency (such as quarterly or monthly) is appropriate?

[7] Energy Security Board, Capacity mechanism High-Level Design Paper, p55.

[8] Energy Security Board, Capacity mechanism High-Level Design Paper, p56

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Should an upper threshold of performance events in a delivery year be considered? If yes, what is an appropriate threshold?

The ESB also suggests that the second payment for availability during times of system stress would be paid regardless of whether system stress events like LOR2 or LOR3 occurred. This creates a quandary. It would mean that capacity payment recipients would receive full payments when there were no supply-demand issues, a potential indicator that too much capacity has been procured. In contrast, during a year with just one or two LOR2 events, suggesting that there is a strong supply-demand balance, a capacity provider could lose a substantial proportion of revenue due to being unavailable for one period or gain a significant capacity payment simply because it was available at that time. Indeed, an unplanned outage at a single generator may be enough to push the system into an LOR2 condition. As a consequence, a single outage could result in an increasingly harsh financial impact for the affected generator, with other generators then benefitting even though there is no guarantee that these generators would be available at any future system reliability stress period.

However, in a year with multiple LOR2 events – suggesting a very tight supply-demand balance – a generator unavailable for multiple events (e.g. missing 3 out of 10) could face less of a financial burden than in the previous example of just one or two LOR2 events. This structure seems to create a strange outcome where more LOR2 events would be better for some generators than a year with just one or two. Indeed, it also appears to fully reward generators if there is no shortage of supply over the course of the year. While a surfeit of capacity would be helpful from a reliability perspective, it would also suggest that too much capacity has been procured, therefore adding extra costs to consumers.

To the extent that there is too much weight put on capacity payments in response to system stress events like LOR2 or LOR3 events, it could overly-penalise generators who are unavailable at some times and potentially over reward generators that do not add to overall scheduled capacity levels.

All told, the ESB's proposed approach suggests that customers will pay most when there is no reliability issue but potentially pay less in years where reliability may be an issue. Shell Energy does not support such an outcome.

In terms of revenue smoothing, Shell Energy has already recommended that costs be passed on to market customers in a predictable and smooth fashion to avoid creating a situation where C&I customers in particular can only look to contract with retailers at certain times of the year. Logically, this would then need to mean that capacity providers would require their payments to be delivered in a similar fashion. As such, regular payments would be more advantageous to avoid a mismatch being revenue and payments.

Are there any other interactions with the existing energy only market that the ESB should consider when designing the capacity mechanism performance obligation? Are there any other compliance issues the ESB should be mindful of in detailed design?

There is a risk that stringent performance obligations could lead to significant penalties for instances of missing availability 'targets' by small amounts. Consistent and regular under-delivery or being unavailable at key times may require further investigation and a claw back of reliability payments, but resources that deliver to close to their contracted volumes for the majority of trading intervals should not necessarily be at risk for small periods where they may not be fully available to their contracted capacity.

Given that the ESB intends to derate technologies with regards to their ability to provide capacity certificates, there are likely to be periods where a generator both under-delivers and over-delivers their contracted capacity, although this will depend on the derating methodology.

AEMO's RERT panel agreement provides a potential approach to assessing performance, particularly for LOR2 or LOR3 events. Under the RERT Panel Agreement, AEMO does not require the precise volume a RERT contract to be delivered at all times. Rather, AEMO sets a performance capability of "at least 80% of the quantity of reserve specified in the reserve contract during each 30-minute period covered".[9] From our perspective this methodology represents a reasonable approach where a minimum quantity of output must be delivered that both ensures sufficient capacity is delivered without imposing too stringent requirements that would create a barrier to entry. The minimum percentage level of actual delivered capacity should be assessed and considered by the ESB as part of more detailed design considerations.

Are there any other implications [i.e. contracts market, other govt, ESB and AEMC reforms] the ESB should consider in detailed design?

A capacity mechanism is likely to have some degree of impact on contract markets yet it is challenging to assess exactly how this will play out in practice. There are a range of potential outcomes. A capacity market may deliver some generators more confidence to plan availability and procure fuel, so could in theory make them more willing to make contracts available to the market. It would likely make generators more willing to offer supply in at close to the short-run costs, as long-run costs would in theory be paid for via the capacity payment. The revenue certainty provided by the capacity mechanism could also reduce the need for a generator to sell contracts since swap contracts are often used by generators to deliver revenue certainty.

However, to the extent that price volatility in the market is reduced as a result of having a capacity mechanism in place, cap contracts may be less valuable from a risk management perspective depending on the level of the MPC. A lower MPC would also tend to lower the value of a cap contract to a buyer as the risk of extremely high prices is reduced. Lower levels of price volatility could also create an incentive for more customers to choose pool price pass-through contracts exposing them to the spot market, again due to the lower potential price volatility. This could lower demand for contracts. However, this may not lead to an overall reduction in the level of supply side resources available to sell capacity certificates but simply a change in how supply side resources are paid for capacity. Similarly, as the level of capacity required is centrally determined and procured, this would not result in the level of capacity procured being less than that required.

As such, it is challenging to assess exactly what the impact of a capacity mechanism will be on the current contract markets which could in effect change to an energy contracts market which manages the risk of wholesale energy spot market outcomes. We do not consider there is sufficient justification to claim the high-level design would enhance contract markets. We can see reasons it could negatively affect contract markets, but acknowledge this is far from a certain outcome.

Ultimately, a capacity mechanism that does not impact the market settings as a driver for contracting would have the least damaging impact on contracting markets. We maintain that our proposed approach of a central buyer purchasing cap contracts from new capacity only to meet any forecast reliability gap would be likely to deliver this outcome.

What is the appropriate combination of performance obligation and capacity de-rating methodologies? Should de-rating be based on pre-defined time periods or a forecast of when the anticipated trigger periods are expected to occur? Given VRE is likely to be particularly affected by any mismatch in the forecast and actual conditions during performance events, should special consideration be given to VRE's compliance with the performance obligation?

Absent from the design paper is a mechanism to reward capacity providers who are available for more than the volume they have sold to AEMO. From our perspective the mechanism looks decidedly one-sided: a provider

[9] AEMO, RERT Panel Agreement 2021-22, p 30.

that delivers less than their contracted capacity will have to pay back funds and be derated further in future years. Whereas a capacity provider that overdelivers appears to see little benefit.

One method to reward capacity for over-delivering its contracted volume could be to allow the over-delivery to offset under-delivery from another generator within the same ownership structure. Another could be to reward generators for actual capacity delivered during times of system stress. This may be important for those that are likely to be heavily derated relative to nameplate capacity, such as VRE, battery storage and demand response.

However, this approach could mean higher costs for consumers if extra payments are provided to generators that overdeliver capacity at times of system stress, or diluted payments to all generators if the same pool of funds is used to reward all generators for availability at times of system stress. Neither of these outcomes appears to be efficient.

Do you think the MPC should be reduced if a capacity mechanism is introduced, and if so, by how much? What key issues should the ESB take into account when considering this issue?

Whether the MPC should be reduced if a capacity mechanism is introduced is an important part of the overall design of the energy market in the context of a capacity mechanism. In considering this issue, Shell Energy considers the ESB needs to be mindful of the broader design of the market.

The Ministerial principles that will apply to the capacity mechanism raise the prospect of each state setting different eligibility criteria for technologies to participate in capacity auctions risks exacerbating existing supply risks. If the MPC is reduced but some technologies are ineligible to receive capacity payments in certain states, the ineligible generators may not be able to recover long-term costs through the energy market. In this case, a lower MPC may in fact lead to a disorderly exit of existing plant – the very issue the ESB is seeking to avoid by introducing a capacity mechanism. A plant that is unable to access either a capacity payment or the high prices needed to recover long-term costs may then change how they operate, potentially by mothballing or only operating seasonally in order to minimise losses and attempt to remain economic before closing.

A lower MPC is also likely to impact technologies very differently. A lower MPC would reduce the price arbitrage opportunities for storage technologies like pumped hydro or batteries as the difference between the lowest and highest possible price outcomes is reduced. Similarly demand response may become less valuable to market customers as the exposure to very high prices is limited. While a capacity mechanism would in theory reward these technologies for being available, conservative derating factors could make them less valuable overall than in an energy-only market, or could create fewer opportunities to dispatch than in the current market.

Shell Energy also identifies the interaction with the Frequency Control Ancillary Services markets as a key issue the ESB must take into account in the context of the MPC. The FCAS markets currently operate on the same settings as the energy market, with a price cap across all eight (and soon to be ten) FCAS markets set at the same level as the energy market price cap. Prices need to be capped at the same level in order to avoid incentivising generators to favour the energy market over FCAS markets or vice versa. It is for this reason that when an administered price period in the energy market is declared, the administered price cap also applies to the FCAS markets. Any change in the price settings of the ancillary services markets would then impact the ability of some new technologies to remain economic in the FCAS markets. This could impact availability and therefore overall costs to end users.

Further, the ESB should also consider the interaction of electricity market price settings with price settings in gas markets. There are links between the settings in each market in order to reflect the importance of gas as a peaking (firming) fuel in the electricity market.

We consider that one of the key advantages of the model we have proposed is it would leave the MPC and contracts markets unaffected. This would avoid the issues that arise if some jurisdictions exclude certain technologies or current resources from participating in capacity auctions. It would also preserve the existing relationships between FCAS and energy markets, electricity and gas markets and the incentives for batteries and demand response to engage in the market.

Cost allocation

Do you agree that costs should be passed on via retailers, rather than NSPs? What do you consider to be the most appropriate mechanism to allocate costs to retailers?

As we stated in our response to questions around retailer participation in the scheme, we consider that it is reasonable for costs to be passed on via retailers and that this should occur in a smoothed fashion using existing NEM settlement processes in a transparent manner. For small customers, capacity mechanism costs should be factored into the regulated price setting process of the DMO or VDO. While for large customers, costs need to be allocated progressively over the course of the year to avoid creating a limited number of windows when customers can contract.

The RERT offers a potential model for allocating costs for system stress events like LOR2 or LOR3. Under the RERT, dispatch and pre-activation costs are allocated to market customers based on actual consumption when the RERT is dispatched. Using a similar model, consumption at times of an actual LOR2 or LOR3 event could be used as a basis to allocate that share of capacity mechanism costs. Based on the ESB's proposed design that would translate to a separate $/MWh charge allocated for the general availability payment throughout the year and a second charge for capacity delivered during system stress events (LOR2 or LOR3).

However, we do see that the structure of the ESB's proposed payments, where generators would receive a second tranche of performance payments even if there were no system stress events during the years, could create an issue. Effectively, the proposed structure means that full payments would be made unless some generators fail to deliver at times of system stress. Based on this structure in Shell Energy's view it would be more efficient to charge the full costs on a smoothed basis based on an annual cost with any clawback from capacity providers who fail to deliver deducted from future payments and returned to consumers on the same schedule.

In contrast, our New Entrant Reliability Mechanism would have relatively transparent costs determined in advance at the time of an auction. If spot market prices were high and the seller of the cap contracts needed to pay funds to the central buyer, then customers would benefit through a refund after these high price events. To our mind, this represents a fairer approach to consumers, where funds can be returned and the costs are limited to the additional level of capacity required to return reliability outcomes to within the reliability standard, rather than all capacity, as proposed in the ESB's high-level design.

Reflecting inter-regional transmission capacity

Shell Energy wishes to note that the discussion of how to treat inter-regional capacity highlights the flaws in a mechanism where states have set differing eligibility criteria. Capacity located in one state may be ineligible to participate in capacity auctions within its own region but could be free to participate in a neighbouring state's capacity auction. While that would allow those otherwise excluded technologies to participate, it would represent a particularly strange piece of policy design, calling into question the need for such state-based restrictions in the first place.

Do you think that Option 1 or Option 2 better meets the assessment criteria? Are there any other factors that the ESB should consider when assessing the relative merits of the options? Are there other ways to ensure that procurement of interstate capacity resources does not exceed inter-regional transmission limits, in addition to the two approaches outlined above?

In line with our comments on how gaps in supply across multiple regions should be determined, Shell Energy strongly prefers the ESB's option 2 for reflecting transmission capacity. That is, capacity providers located in a neighbouring region would be explicitly permitted to participate in the capacity mechanism, with compliance obligations tied to the region they are supplying. This makes the most sense from a perspective of delivering a least cost solution to consumers and also reflecting the physical nature of the network. The transmission network is interconnected at present, with more interconnections being flagged in AEMO's Integrated System Plan (ISP). Requiring all capacity to be procured only from within the same region would ignore the value that interconnectors provide and mean higher costs for consumers as more capacity would be needed than is actually necessary.

The ESB's high-level design then asks about how the capacity mechanism should reflect inter-regional transmission capacity and floats two further options if inter-regional capacity is allowed to participate: transfer rights or transfer limits. Under the transfer rights model, generators would have to acquire a separate inter-regional transfer right. This approach would seem to create a bias against procuring inter-regional capacity as, depending on the auction prices realised in each region, generators in another region would have to factor in the cost of procuring the transfer tights. Shell Energy prefers the alternative approach of transfer limits where interstate capacity sales are restricted by the de-rated interconnector limits. This appears to be a far more reasonable approach that would see inter-regional capacity compete on the same basis as intra-regional capacity.

Do you think that where a market interconnector exists between two regions, it should be the entity that is eligible to submit inter-regional capacity bids?

Do you think that proposed new market interconnectors should be able to participate in the capacity mechanism?

We agree with the ESB's proposal that market interconnectors be eligible to participate in the capacity mechanism and that regulated interconnectors should be excluded. Allowing market interconnectors to participate may create a further incentive for market interconnectors to be built.