7 April 2021

The Design Development Team
Northern Territory Electricity Market Priority Reform Program
Department of Treasury and Finance and Department of Industry, Tourism and Trade
Darwin NT 0800

By email: electricityreform@nt.gov.au

Dear Design Development Team

NTEM priority reform package policy position papers

EDL is a leading global producer of sustainable distributed energy. We own and operate around one hundred power stations across Australia, North America and Europe including our Pine Creek generator connected into the Darwin-Katherine Power System (DKIS).

Thank you for the opportunity to provide a submission to the Northern Territory Electricity Market (NTEM) Priority Reform Package Policy Position Papers published in January 2021. This submission responds to the Reliability Priority Changes and Essential System Services (ESS) Review Papers (the Papers).

Broadly, EDL supports the need to reform the NTEM to account for the changing nature of electricity supply and demand. Importantly, for a market the small size of the NTEM, those reforms must be carefully considered and implemented to ensure that the likely competition benefits outweigh the costs, including any market inefficiencies, associated with introducing and maintaining them.

We have set out in the attachment to this letter our views on a number of issues and addressed specific questions raised in the Papers. In summary, EDL:

- supports the introduction of a capacity mechanism with that capacity determined by an Independent Market Operator.
- considers that further details regarding the operation of the mechanism, including worked examples, need to be provided to ensure that the mechanism works efficiently and without adding unnecessary system risk, particularly in the early operating stages.
- submits that a tendering process would deliver workably competitive ESS outcomes, that T-Gen's pricing as part of that process should be rigorously reviewed.

Should you wish to discuss any of the above, please contact Neil Duffy, Commercial Manager RE on 0478 544 925 or neil.duffy@edlenergy.com.

Kind regards

Geoff Hobley
General Manager, Remote Energy

Attachment

Reliability Priority Changes Paper

EDL notes that the Darwin to Katherine system (DKIS) is small and its capacity to absorb inefficient generation location and performance is highly limited. In addition, new generation is lumpy compared to the total system load (around 10% of peak load every time a new generator is connected). These two characteristics make the system vulnerable to negative impacts from poor market signals. There is a risk that a fully free market would result in sub-optimal generation location on the network or in a way that introduces inefficiencies.

EDL prefers a model where a central authority determines the volume, type and location for new generation to enter the system. Proponents could then submit proposals to meet those criteria at lowest cost. This approach could also provide a mechanism for competing against existing plant if that plant were unable to continue to provide capacity at a cost that is competitive against new entrant generation. Centralising the procurement enables system management to satisfy security requirements while also aiming towards meeting government objectives, such as the proportion of renewable power.

Q1. What other matters need to be considered in determining who should undertake the Reliability Manager function for the DKIS?

A1. System Control may be incentivised to over-supply the system to make the task of managing the system easier. An Independent Market Operator would be preferable with transparency over the selection process fundamental.

Section 3.1 Options for ensuring capacity adequacy

EDL prefers an administrative/centralised mechanism for determining capacity adequacy as the system is too small to deliver a net benefit from a fully market-based approach. Setting capacity procurement as a retailer obligation creates a risk that sub-optimum generation for the system is procured. The obligation should sit with the centralised Reliability Manager.

The target should be volume-based for such a small market as it may not be able to tolerate the volatility that may arise from purely economic signals. Once the volume of capacity is determined, it can then be procured at whatever cost the market needs to deliver. Price limits can be set to avoid unforeseen high and low pricing outcomes.

Section 3.2 Capacity procurement approach

Capacity should be procured by a central authority with the retailer having the obligation to pay for its share. This is similar to the West Australian Wholesale Electricity Market (WEM).

Putting the obligation to procure capacity on retailers makes new retailer market entry more challenging as they will most likely need to procure partial capacity from an existing facility (assuming they are not fully contracted already) or it may incentivise smaller, potentially less efficient facilities to connect. This is exacerbated by renewable generation targets, which might force retailers to contract with multiple facilities. Conversely, generators will potentially need to strike up long-term contracts with multiple retailers to reach financial close. This makes achieving financial close challenging and will impact system investment.

Centralising the mechanism removes risk for the retailers, generators and System Control. Furthermore, it doesn't preclude the continuation of the existing PPA structures. Capacity accreditation can occur as planned and bilaterally traded as part of separate contractual

arrangements. This is what currently occurs in the WEM with bilateral capacity trading often coupled with energy acquisition.

Q2. Are the proposed arrangements for acquiring capacity an appropriate balance between cost to administer, certainty and flexibility for retailers in choosing how to procure capacity?

A2. A central authority to purchase all capacity should not be too costly to administer. This process could be run annually, similar to the WEM. The central authority could consult with others, including System Control, to determine the best type and location of new capacity. Retailer participants would be obliged to pay for their share of that capacity.

Section 4 Detailed design elements of the reliability framework

Obligating retailers to procure capacity creates the potential for generators to need to contract with multiple parties for portions of their generation. This will create issues as to where penalties will lie if the generator under-performs. If generators cannot contract separately for portions of a generator, then it is likely the market will be over-supplied, creating inefficiencies.

Setting the capacity price is crucial to the market. More detail is required as to how the reference capacity price is to be determined. It is not clear what benefit the marginal one megawatt (MW) cost model provides. One MW may not be the most efficient size of generator to add as the marginal unit on the DKIS. This is something that needs to be detailed for stakeholder comment before the method is finalised.

Q3. Do the proposed timeframes in Figure 1 allow sufficient time between the Reliability Manager advising capacity obligations for Year 4 and retailers notifying the Reliability Manager of their purchasing intentions (that is, either the retailer will procure for itself or the retailer requests the Reliability Manager to purchase on its behalf)? If no, please explain your answer.

A3. The proposed timeframes appear sufficient to allow development of new generation. However, the requirement to contract for load against a forecast four years ahead is inappropriate and supports a central capacity manager. There is the real possibility that load moves around in the period between being contracted and when it is required. A central capacity manager who is the contracting authority would procure all capacity for the market and assign cost to retailers based upon their market share at the time the capacity is required.

Q4. What issues and constraints need to be considered in adjusting contracts in response to capacity obligation resets in earlier years (Years 1 to 3), noting the rolling nature of the capacity mechanism should mean these are relatively minor?

A4. See answer above.

Section 4.1 Determining the forecast of required accredited capacity

It isn't clear in the Paper why fuel cost, heat rate and variable opex are required to undertake capacity planning. There is also a need to understand the accreditation method for renewable energy in some detail. Small changes in the method can make enormous differences in how this is treated.

Section 4.2 Allocating capacity requirements to retailers

The proposed mechanism of retailers contracting directly with generators will be highly problematic and create barriers to entry for new retailers. It is much better to install a central Reliability Manager who contracts for all capacity that the market requires.

Section 4.3 Ex-post review and reconciliation

It doesn't appear to make sense that retailers pay the penalty for generators not meeting their capacity obligations. Ultimately, the generator should be penalised and the penalty returned to the retailer to compensate them for the underperformance of capacity in the system. This approach is similar to the WEM. Stakeholders also needs to understand whether the proposed four month period is long enough for a final settlement position for capacity. This may be too short to properly allow for meter reading schedules.

Section 4.4 Capacity price

Detail is required as to how the marginal cost of existing capacity will be calculated. The one MW of marginal capacity may not provide an efficient price for additional capacity. It is more likely that additional generation will be larger than this, providing a lower cost of the marginal capacity per MW.

Section 5.1 Controllable capacity

The proposal to discount capacity based upon the previous 12 months' performance is inappropriate. It would be better to provide a process that allowed for the full accreditation of capacity, provided sufficient evidence could be provided as to the reliability of that capacity. For example, a generator may have had poor performance in the previous year but spent significant capital to improve. It shouldn't have to wait a further year to receive the benefit of the improved reliability. Likewise, if the market doesn't recognise the improved reliability, there will be too much capacity on the system.

It would be preferable to accredit the generators for their expected capacity and then have them pay penalties if they fail to deliver. Those penalties would then pass to the retailers in compensation for the underperformance of the capacity. As an alternative, the penalties could be retained by the Reliability Manager who could use the funds to contract for any additional temporary capacity if required.

Q5. Is a more complex process warranted for determining accreditation of controllable units? If so, please explain why, and describe your proposed process.

A5. EDL proposes a mechanism similar to the WEM, adjusted as required for the NTEM, rather than imposing the obligation on retailers to contract for capacity. The accreditation process should be decoupled from retailer contracts.

Q6. Are the proposed timeframes (previous 12 month performance; 48 hour pre-approval; 30 minute start window) suitable for deriving the discount factor?

Q6. It would be better to have a penalty mechanism for failing to provide capacity in the year of operation, rather than the year prior. Generators should apply for scheduled outages and, if approved, should have appropriate planned maintenance times without penalty. The Reliability Manager and System Control should determine the schedule to ensure that there is sufficient capacity available during peak periods. Generators that are unavailable due to network maintenance should not be penalised.

Section 5.2 Intermittent generation and storage

It would be valuable to be provided with additional detail on the proposed intermittent generation and storage in order to understand whether the mechanism put forward in the Paper will efficiently achieve its objectives. A working model or worked examples would help.

Q7. How important is certainty in the level of capacity accreditation granted to intermittent plant, noting generators have access to capacity and energy streams of income?

A7 Certainty of revenue streams will impact project risk for intermittent generators. This may increase the cost of these projects and may impact the Government's stated objective of increasing the level of renewable generation in the market.

Q8. What indicators provide the effective signals to prospective entrants about the benefits of connecting to the network including in areas where access is likely to be constrained?

A8. This should be centrally administered. The Reliability Manager should be prescriptive in stating the location, volume and type of capacity that is sought for the market.

Q9. What approach – a variable accreditation approach or an approach that preserves the accreditation of incumbents or early movers – is likely to result in long term efficient outcomes and best serve the interests of consumers? Why would that approach best achieve those outcomes?

A9. Incumbent capacity, both existing and as it becomes established in future, should be preserved. This mitigates the risk for both existing and new entrants, promoting the efficient provision of capacity without parties needing to provide for risks that may not eventuate.

Section 6.1 Reserve factor

Approved outages should not incur any penalty. Beyond this, a number of important questions don't appear to have been addressed in the Paper:

- How do planned outages and subsequent unplanned outages interact on the reserve scaling factor?
- How does the reserve scaling factor and the provision of capacity interact with the provision of ESS?
- Is capacity used for ESS also able to provide for the overall capacity requirement of the system or not?
- Why is the capacity price linked to an energy price in the worked example?

Section 6.2 Capping of reserve factors

This section of the Paper is difficult to follow. Greater detail is required for EDL to be able to provide meaningful comment.

Section 6.3 Paying for capacity in excess of accredited capacity

There should be no payments for additional capacity as this will lead to chronic over-provision of capacity.

Q11. Will the proposal to operate a virtual capacity mechanism and the associated timeframes be helpful in assisting participants to understand and prepare for full operation? Please explain your response.

A11. A virtual mechanism may deliver value by providing a forward view on the need for additional capacity and/or uncover potential shortfalls. However, doing so may risk the over-provision of capacity in the meantime.

Q12. What other information or initiatives would be helpful to inform participants on capacity mechanism operations to prepare for live operation of the mechanism in 2025-26?

A12. A mechanism that provided the right signals for the retirement of ageing or inefficient generation would be helpful.

Q13. Alternatively, rather than applying a virtual capacity mechanism until 2025-26, do you consider that an earlier commencement of a full operational mechanism is possible and preferred? Please explain your response.

A13. An initial virtual capacity mechanism is preferred to ensure the process is robust before commencing the full operational mechanism.

Section 8.1 Legislative change

Q14. Do stakeholders have an alternative preferred option to implementation through legislative and regulatory change? If so, please describe the approach and provide reasoning for why it is preferred.

A14. There needs to be a balance between stability and flexibility. Broadly, legislative changes are preferred to lock in key outcomes, structures, functions and roles. However, there also needs to be a mechanism to provide for fast rule changes, particularly at the start of the NTEM, as there may be unforeseen outcomes that will need to be adjusted for rapidly.

Essential System Services (ESS) Paper

EDL notes that there are only a few synchronous generators in the market and that increasing solar capacity in the NTEM means those few players will remain key to maintaining network stability. However, this does not mean that T-Gen should be the default provider of ESS.

There are other ways of introducing meaningful competition that can lead to lower costs to end consumers. Doing so doesn't require establishing a near real-time market, which would be expensive to set up and operate. Rather, EDL recommends a bidding process, where contracts for the provision of (to be defined) ESS are tendered and awarded to suppliers on a lowest cost basis. This could be done quarterly or annually using bilateral contracts. The contracting timeframes may be able to vary between the different services. This approach would deliver much of the competition benefits without the cost of running and setting up the systems.

We agree that the cost of ESS should be borne by the recipient of the services, rather than through a codified $5.40 per Megawatt-hour (MWh). Currently, T-Gen has a market monopoly with no transparency as to its ESS pricing. That pricing should be subject to rigorous review and this should continue once the market is open to other providers. It should only cease when T-Gen is no longer required to supply ESS, either through the market or as a supplier of last resort. A periodic review by the Utilities Commission, based upon the cost of running the relevant equipment, would be appropriate.

EDL notes the proposal in the Paper to allocate costs for contingency raise based upon the size of the generator. Consideration should also be given to failure rates. If a generator were 100% reliable, it would not require any contingency raise service. If it were highly unreliable, this provides a strong incentive to improve that reliability.

It is also important to highlight the interplay between the Generator Performance Standards (GPS), the ESS and other current requirements on generators that may constitute provision of ESS but which aren't currently remunerated or recognised (we note that Section 6.1 of the Paper recognises the fact that Pine Creek already provides ESS services but is not compensated for doing so). The GPS should be revised to remove overlap with the ESS.

Section 3.1 of the paper proposes that two Frame 6 units will be required for ESS provision. EDL submits that the ESS standards should be set out in a regulatory instrument rather than a System Control instrument. Further, the Paper does not demonstrate why two Frame 6 units should be necessary. This needs to be explained.

The Paper proposes introducing the ESS through amending the System Control Technical Code, Network Technical Code and Planning Criteria and/or the Northern Territory Electricity Rules. This appears reasonable, provided that the mechanism for fast rule changes is present. It is also important that the development of standards and rules is separated from the party responsible for implementing them. In the WEM, the failure to separate rules development from the Independent Market Operator created issues.

Finally, EDL makes several comments on the proposed ESS role of System Control:

- Does System Control have the necessary systems to manage ESS at a higher resolution in order to achieve the forecast efficiency improvement? If not, has the cost of new systems been assessed to ensure the benefit of improved efficiency outweighs the cost of new systems?

- Is System Control the right body to provide the specification and quantum of each ESS required? It may be incentivised to over-procure ESS to make it easier to manage the power system and achieve its reliability targets. Ideally, this function should sit with an independent Reliability Manager or be ring-fenced.
- If System Control was responsible for developing ESS specifications, it would need some form of independent oversight. Again, the Utilities Commission may be appropriate provided it had the technical expertise to review and provide constructive input into to the process.