Wednesday, 10 April 2024

Lodged online via email at TransmissionSTPISReview@aer.gov.au

Clean Energy Council submission on Electricity Transmission Service Standards Incentive Scheme

Dear AER STPIS Review team,

The Clean Energy Council (CEC) is the peak body for the clean energy industry in Australia, representing over 1,000 of the leading businesses operating in renewable energy, energy storage, and renewable hydrogen. The CEC is committed to accelerating the decarbonisation of Australia's energy system as rapidly as possible while maintaining a secure and reliable supply of electricity for customers. The CEC is also working with market bodies and government to unlock the potential of the existing and future grid and attract investment through market certainty.

We welcome the opportunity to comment on Issues Paper related to the Service Transmission Target Performance Incentive Scheme (STPIS). We agree that the market impact component (MIC) and network capability component (NCC) of the STPIS need to be reviewed. We also agree with AER's analysis that indicates the MIC is not working as intended and the NCC is being under-utilised.

Overview

In regards to the MIC: the CEC recommends the AER pursue a fundamental redesign of the MIC, to reflect its impact on renewable generation and storage revenues and investment more broadly. Spot price effects are no longer the best indicator of long run market impact and consumer costs. Instead, we consider that generator revenue impacts, and consequential impacts on investment efficiency, should form the basis of the MIC.

Maintaining discipline in how planned outages are managed is important for revenue certainty and ultimately investment certainty. The market performs better when distortions and curtailment is understood from the outset. Lack of an incentive for good outage planning can lead to continued loss of revenue if not properly accounted for by transmission network service providers (TNSPs).

In regards to the NCC: The CEC strongly supports the continuance of the NCC as a core component of the STPIS. There is, and will continue to be, a very high value to consumers from technological improvements in how the grid is managed, particularly any measures that can be used to increase utilisation and optimisation of the available network.

Technological developments and changes in TNSP investment strategies – particularly the increasing interest from many TNSPs in pursuing non-network solutions – means the number of potential solutions that can be incentivised under the NCC will increase. TNSPs should be able

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to access a range of lower cost options to increase network hosting capacity and tackle congestion, as this will ultimately bring down energy and network costs for consumers.

Below we will elaborate on each of the components under consultation, with a note at the end on the service component (SC).

Market impact component

The intended purpose of the MIC set out in 2007 was to incentivise TNSPs to take planned outages at a time when they would have a minimal impact on the spot market. In 2007, fossil fuel sources of generation were prevalent, with support from hydro power. This generation mix resulted in inter-regional congestion and the MIC was calculated as the marginal cost of congestion. Upward of $10/MWh threshold would define if an outage event would have a negative impact on the market. Fewer events and TNSPs would receive an incentive.

We consider the MIC needs to be amended. The AER's analysis in the Issues Paper clearly makes the case why the MIC is not achieving the desired outcome. TNSPs have incurred maximum penalties irrespective of their outage management plan. It is also unclear what behaviour is MIC seeking to incentivise.

The CEC recommends that the MIC itself be redesigned to reflect changing power system and market conditions, rather than the more incremental changes presented in the Issues Paper.

We also recommend against revoking the MIC entirely, without a replacement scheme. It is important that TNSPs face clear and meaningful incentives to take outages at times which minimise market impacts. Of course, consideration must also be given to what reasonably lies in the TNSPs' control when redesigning the MIC.

The CEC therefore recommends the AER undertake a fundamental redesign of the MIC, potentially in conjunction with the AEMC, if rule changes are required. We have set out several key principles we consider should be considered by the AER when doing so.

Broad consideration of market impacts to focus on revenue and investment impacts for renewable generation and storage

The CEC considers the priority focus at this stage of the energy transition should be on supporting investment in renewables to replace thermal generation assets before they retire. This is central to maintaining reliability as well as stable wholesale and retail prices for consumers over the medium to long term.

On that basis, we recommend that metrics used by the AER in the MIC should focus on long term investment impacts, which are primarily impacted by issues around revenue certainty for renewable generation and storage development, rather than being focussed on short term spot market outcomes.

This review therefore represents an opportunity to refocus on the investment impacts of network outages. In particular, a revised MIC should consider what revenue impacts will flow from outages, on the basis that this will have the most marked impact on renewable investment. This should include impacts on solar / wind farms and batteries being offline or constrained, resulting in:

- Revenue loss for not being able to bid for and be selected to dispatch electricity at times of high market prices. Analysis from US energy only markets demonstrates that any outage that correlates with super peak pricing events can dramatically reduce the total revenues available to assets, especially energy storage, which can markedly reduce the viability of investment in those assets.[1]
- Revenue loss for not being available to supply electricity to facilities or batteries (outside the spot market), where the TNSP's transmission infrastructure is used
- Batteries being unable to charge during the day when prices are negative (in order to discharge when demand is high)
- Curtailed ancillary services such as FCAS and potentially not being able to meet system security contractual arrangements, such as system strength or voltage control network support agreements
- Reducing investment certainty when there are repeated or prolonged outages.

The impacts of outages are exacerbated by the fact that solar and wind farms cannot fulfill their full revenue potential because of curtailment. Spot prices represent a narrow metric that does not consider the long-term impact of generators being constrained off due to outages.

The CEC strongly recommends against implementing a revised MIC which excludes impacts on semi-scheduled generators or is limited to main lines as this will not account for how renewable energy will be impacted in the short or longer term.

The CEC advises the AER to consult with the renewable energy industry to better understand how outages impacts them. To date, generators already incur losses, and this will only exacerbate in the future.

We also advise the AER to investigate how planned and unplanned outages intersect to impact generators. It would be useful to determine to what extent a historical performance is relevant in the future.

Recognising TNSP challenges in managing outages

The CEC also recognises that TNSPs face new challenges in scheduling outages as the NEM generation mix changes. We understand that the traditional shoulder periods are becoming shorter as demand patterns change, while new power flows are emerging as VRE levels increase.

All these factors increase the challenges faced by TNSPs and we are supportive of recognising these challenges in the design of the MIC. TNSPs must be able to conduct maintenance, as well as new works and energisation of new major transmission infrastructure and should not be only penalised for doing so.

We consider here that where TNSPs cannot move an outage, it is imperative that generators receive as much notice as possible for the rescheduled planned outages. As per below, we also consider that AEMO should have much greater involvement in this process, given its unique capabilities in modelling power system outcomes. Outages should be planned and scheduled

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[1] ERCOT: The cost of unavailability for battery energy storage | Modo Energy

on the basis of AEMO's analysis as to when they are likely to have the least impact on revenues for renewable generators.

Need to clarify and expand AEMO's role

We recommend clarifying the role AEMO has in planning transmission outages and recommend that AEMO have a greater involvement in planning the time and duration of transmission outages.

AEMO already has a significant role in determining when TNSPs can take outages as:

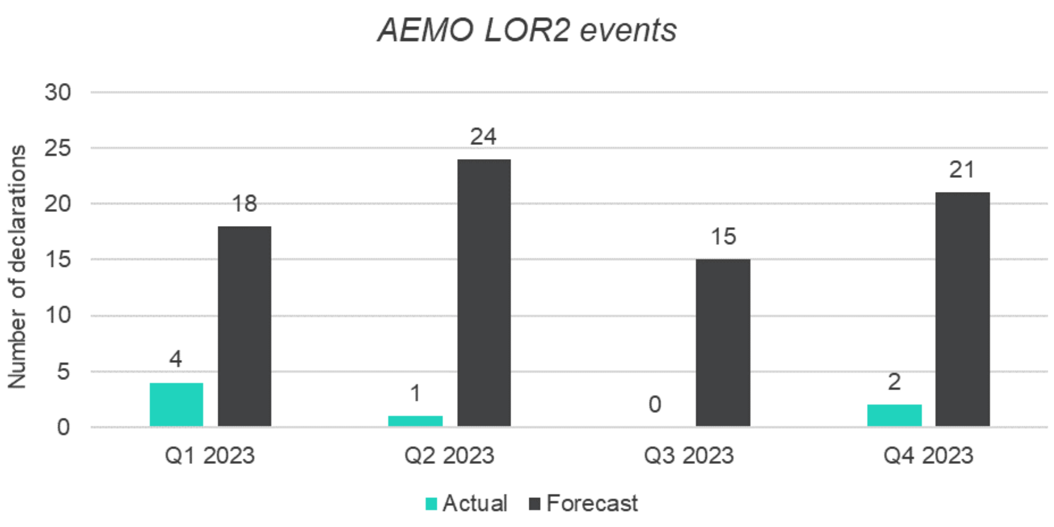
- We understand that TNSPs often have their planned outages cancelled by AEMO because of forecast LOR2 conditions in the lead up to the outage. In practice this results in TNSPs negotiating a new time with AEMO
- Specialist staff within AEMO already assess the outage bookings in the Network Outage Schedule, and the forecast demands for the period, and then provide TNSPs with feedback on the likelihood of each outage proceeding.

AEMO is the best position to forecast the market impact of outages, considering both spot market outcomes as well as revenue impacts, and impacts on system security and reliability, in the short, medium, and long terms. We understand that only AEMO has the modelling tools to undertake this function, as well as the regulatory remit to direct TNSPs to undertake certain actions.

As AEMO has knowledge of planned outages from all TNSPS, we recommend that AEMO be the coordinator of outages between TNSPs across NEM regions to minimise impact on generators. Consecutive works affecting generators could instead be scheduled at the same time to reduce the number of hours or days a generator incurs revenue losses.

Broad consideration of LOR2

We understand that planned outages can be cancelled on short notice if AEMO forecasts LOR2 conditions in the lead up to the outage. We recommend the AER engage with AEMO to explore the impacts of this outcome. Most forecasted LOR conditions do not eventuate. For example, in Q4 2023 there were 2 actual LOR2 events from 21 forecasted.



In our submission[2] to AEMO's review of its reviewable operating incidents framework, we noted that the forecast uncertainty measure (FUM), which underpins AEMO's issuance of LOR notices, has a number of consequential impacts across the NEM. In particular, we noted that issuance of LOR notices impacts on when network outages are recalled. This obviously has implications for the matters under consideration by the AER in this consultation.

We therefore recommend that the AER engage with AEMO to determine whether the FUM / LOR issuance framework can be amended to recognise the consequential impacts of LOR declarations on outages and the MIC.

The CEC also recommends that consideration be given to AEMO's ability to procure services to assist in managing impact of planned outages, or otherwise minimising market impacts of said outages. For example, this might involve AEMO procuring a temporary service from a battery or synchronous generator to provide a temporary SIPS, allowing AEMO to continue to maintain system security while the planned outage continues. This temporary service could be used to maintain system stability, for example, as an alternative to the renewable generation curtailment that might otherwise be necessary.

We consider there are various mechanisms that could be used to enable AEMO to procure these temporary services. The Network Support and Control Ancillary Services (NSCAS) provisions, for example, could be adapted to include an ability for AEMO to procure services to help ameliorate the effects of a planned network outage. Equally, the 'transitional contracting' mechanism currently under development by the AEMC through the Enhancing System Security frameworks rule change might be used here.

The CEC appreciates this may fall outside the current scope of this review, however, we encourage the AER to engage with AEMO and the AEMC to explore how these contracting frameworks might be used to reduce the impacts of outages.

Coordination to improve transparency

There is a need for increased transparency of planned outages across a wider area to improve coordination. A generator could be impacted by consecutive outages in different jurisdictions, especially when a generator is at a border. Better visibility could result in a reduced number of hours or days a generator incurs revenue losses.

Again, we consider AEMO could play a coordinating role here.

Development of outage planning guidelines

We do not recommend substituting the MIC with a compliance approach, on the basis that clear financial incentives are the most effective way to drive efficient operational behaviours from TNSPs.

However, we consider that there is value in AER developing guidelines, (after consultation with TNSPs, AEMO and industry), for TNSPs (and AEMO in an expanding role) to follow in planning outages. These guidelines should also include check points to determine whether the planned

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[2] Clean Energy Council, Reserve Level Guidelines submission, March 2024. Available at cleanenergycouncil.org.au

outages can go ahead. The AER may be able to build upon the current TNSP's network outage management plans.

The AER could consult with industry in the development of these guidelines to ensure the planning transmission outages have a minimum impact on the market (including generators).

The AER should ensure that any penalty on TNSPs reflects the degree TNSPs can plan for, and control, when outages take place. We recommend that TNSPs should not be penalised where they have followed the planning guidelines and checkpoints for proceeding with outages and/or sought AEMO's prior approval for the timing and duration of the outage.

Alternative option

As an alternative to the options outlined in the Issues Paper, the AER could consider simplifying the MIC, at least during the rapid transition of the power system when TNSPs are undertaking significant (and sometimes overlapping) transmission infrastructure works. The simplified scheme would require TNSPs to take outages at a time and for a duration agreed in advance with AEMO.

It is likely that TNSPs would still need to be incentivised (by way of rewards and/or penalties) to propose outages for AEMO's approval during periods when demand is low, or when renewable generation is least impacted.

Network capability component

The NCC is important to incentivise TNSPs to allocate resources for low-cost projects that provide significant benefits to both consumers and generators.

The CEC recommends the NCC be expanded and modified so that TNSPs can flexibly take advantage of emerging technologies and non-network solutions to better utilise the existing capacity of the grid.

Broadly, the CEC recommends:

- The NCC be expanded to permit inclusion of more low-cost / high value projects
- There should be flexibility for variations to the NCC during a regulatory period to include
  - Projects based on new technological advancements or services that better utilise the grid's capacity
  - Projects identified by developers / generators during the regulatory period that will deal with grid capacity constraints
  - Variations where there are supply chain constraints affecting identified projects
- We also recommend the RIT-T threshold be increased, from the current level of $7 million, to a higher value. This would have the effects of reflecting increased input costs and inflation, while also providing greater opportunity for TNSPs to find innovative (and still relatively low cost) solutions to increase overall efficiency of network utilisation.

Focusing on the right metric

The CEC considers focusing on the number of projects considered under the NCC is not the most effective way to measure the success of the scheme.

Instead, we recommend the AER focus on the value add of each project, since relatively low-cost options can yield high returns.

We acknowledge that some regulatory periods have seen more projects allocated under the NCC allowance than others. However, this ebb and flow is not a reason to remove the incentive. The relevance of the component does not change when the budget is not fully committed.

Focussing on the number of projects can also be misleading. For example, some TNSP members have advised us that although in the last two regulatory periods the number of projects appear to have declined, this was mainly because once the scheme was introduced there was a backlog of projects However, many existing projects underway are on a business-as-usual basis, thus reflecting a normal level of projects.

Changing the current $7 million threshold

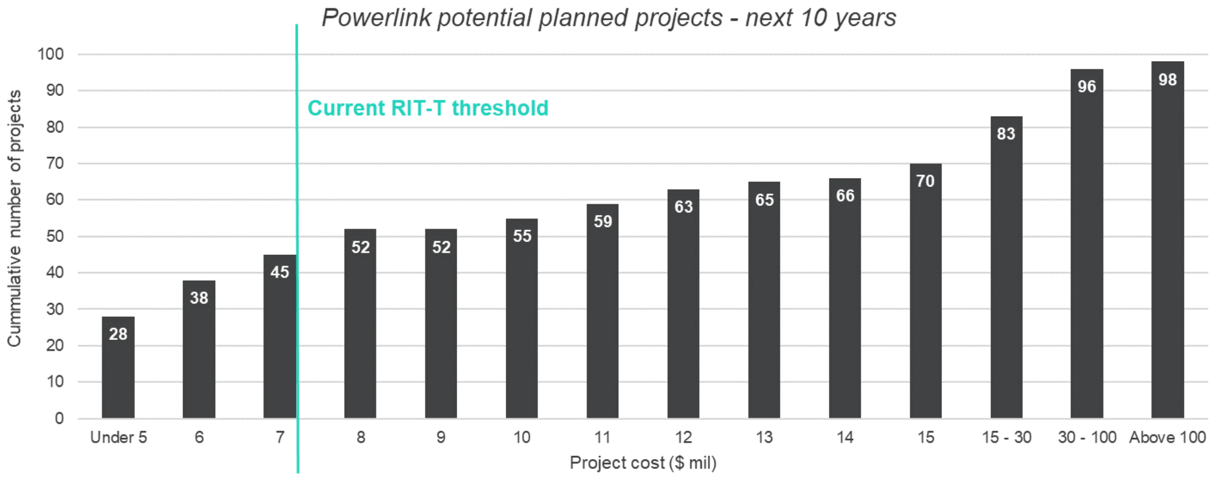
The NCC captures projects below the RIT-T threshold. While the RIT-T is rightly designed as a more onerous process for TNSPs, we consider that if set too low, the administrative costs of complying with the RIT-T will simply mean that low cost / high value projects will simply not be considered.

The RIT-T threshold therefore plays a key role in the number and type of projects that can be effectively captured under the NCC. The ability to identify suitable NCC projects has been made more difficult because the $7 million threshold has not been revised in a long time, which means it has failed to keep pace with inflation as well as the general increase in costs due to post pandemic supply chain bottlenecks.

The CEC therefore recommends the AER increase the RIT-T threshold, to allow more projects to be included in the scope of the NCC, and to account for the effects of inflation and supply chain tightness.

As an example of the number of additional high projects that might be captured under the NCC by a revised RIT-T threshold, we note Powerlink's 2023 Transmission Annual Planning Report[3], which shows that over the next 10 years there are an additional 10 projects with a value between $7 million and $10 million and another 10 projects with a value between $10 million and $13 million. The value add of these projects could further inform the rationale of increasing the threshold.

[3] Powerlink Transmission Annual Planning 2023 – Appendix 10, page 197 – 212, https://www.powerlink.com.au/sites/default/files/2023-11/2023%20Transmission%20Annual%20Planning%20Report%20-%20Whole%20Document.pdf



An analysis across all TNSPs is likely to identify more NCC projects if the threshold were raised. There could be even more projects identified if additional flexibility were added to the projects as discussed below.

Role of other participants in identifying NCC projects

There is potential for other market participants to identify and recommend to TNSPs a NCC project and where to be implemented. For example, if a generator or developer identifies there is a constraint which is binding at a particular location all the time, there should be an opportunity for them to work with the TNSPs to submit a joint proposal to AER. This may be proposed ahead of a regulatory period, but the NCC could also allow for flexibility for TNSPs to identify and add such projects during the 5-year revenue period.

Value in the future

TNSPs should be able to fully utilise emerging technologies and non-network solutions under the NCC to deal with grid constraints, especially as their costs are likely to fall over time.

Emerging technologies

We note there are several new technologies currently being tested and deployed:

- Dynamic line rating for more precise measurement of temperatures in real time
- Reconducting for reducing electrical resistance by switching materials
- Advanced power flow controls for switching power flow across lines.

Dynamic line rating is commonly used by TNSPs as it has the potential to increase network capacity by 20 to 30%. Several TNSPs are deploying the Smart Valves (advanced power flow control) technology. For example, ElectraNet has reduced wind curtailment and increased network capacity by 17 MW; AusNet is unlocking capacity of 15 MW by routing power flows onto an underused western 330 kV line of 15 MW; and Transgrid has unlocked 170 MW capacity at their Stockdill and Yass substations in the ACT[4].

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[4] Super cheap transmission upgrades could double capacity and open floodgates for renewables | RenewEconomy

Non-network solutions

The NCC should be revised to allow for consideration of low-cost non-network solutions that can potentially deliver material reductions in system congestion.

For example, batteries can provide services which allow for better utilisation of grid capacity - through voltage support, provision of system strength services as well as system integrity protection scheme type solutions. Similarly, it may be possible to upgrade a grid following inverter to grid forming, further increasing system stability, and reducing congestion.

These kinds of solutions can, and are, captured under the RIT-T. However, as per our comment above, there is a high likelihood that there are a significant number of lower cost services which might be developed through the NCC, but which do not currently get picked up due to the RIT-T threshold. These services could potentially deliver marked increases in network capacity which would outweigh the costs of provision.

Without the NCC, the TNSPs would not be incentivised to implement the efficiencies that can be obtained from these emerging technologies and services. This is because otherwise the NER incentivises TNSPs to focus on large capex rollouts. The resources needed (i.e. staff, time, modelling) to implement large projects under the RIT-T are the same as for small projects.

Need for flexibility

The NCC needs to be flexible enough to incentivise TNSPs to fully utilise the scheme.

Lead time for projects

TNSPs have to submit the list of NCC projects at the beginning of the regulatory period and work in identifying these projects starts well before that. This lead time can stifle innovative solutions since technology advancements could occur during the period but TNSPs cannot capitalise on them. TNSPs, working with developers, may identify suitable projects during the regulatory period.

TNSPs need to be incentivised to fully utilise the NCC scheme by being in the position to add projects during the revenue period.

Variations due to supply constraints

During the energy transition, projects are likely to face challenges in securing materials, or costs rising materially, because of supply constraints. With long lead time from the time when projects are proposed, TNSPs should be allowed to submit requests to modify a project’s cost or extend the deadline. A list of exemptions could be drawn to allow for this flexibility to be incorporated into the design of the scheme.

Minor capex projects

The NCC should continue to capture minor capex projects (below the RIT-T threshold), for example, the use of series capacitor banks to increase transmission power capability. TNSPs could also flag these expected projects as part of their Transmission Annual Planning Report.

Penalties

As noted above, TNSPs should not be penalised for matters outside their control and therefore they should be able to seek modifications to a project due to supply constraints.

To further incentivise TNSPs to use the NCC, we recommend that the calculations of the penalties be based on the expenditure of the project rather than a percentage of MAR.

Service component

Although not in scope for this review, we support Energy Networks Australia (ENA) proposition for a re-evaluation of the SC. The target based on past performance has resulted in the component mainly acting as a penalty. With more unexpected weather events providing TNSPs with greater flexibility and allow system minutes threshold to be aligned with those that apply to targets, caps, and floors.

As always, the CEC will work with the AER to support defining the STPIS scheme in ways that is in the long-term interest of consumers and provides value for generators. We appreciate the opportunity to share industry perspective and look forward to further engagement in next steps. For any questions, please contact Diane Staats (dstaats@cleanenergycouncil.org.au) or Ana Spataru (aspstaru@cleanenergycouncil.org.au).

Kind regards

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