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Via electronic lodgement

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Dear Kris

AER Issues Paper – Transmission STPIS Review (MIC and NCC)

AusNet welcomes the opportunity to provide this submission to AER's review of the service target performance incentive scheme (STPIS) for transmission network service providers (Issues Paper).

AusNet is the largest diversified energy network business in Victoria with over $12 billion of regulated and contracted assets. It owns and operates three core regulated networks: electricity distribution, gas distribution and the state-wide electricity transmission network, as well as a significant portfolio of contracted energy infrastructure.

In this submission, AusNet:

1. Agrees that the Market Impact Component (MIC) scheme, in its current form, no longer works as intended, nor would the alternative MIC options in Issues paper substantively redress this;

2. Considers that, the MIC scheme fails to interact effectively with the Victorian planning regime, resulting in inefficient outcomes for customers and a significant administrative burden for AusNet and AEMO; and

3. Supports the Network Capability Component (NCC) scheme as its objectives to find low-cost improvements remains relevant, particularly as the existing Victorian network is expected to substantially change.

AusNet acknowledges and supports the Energy Networks Association's submission to this STPIS review.

Market Impact Component Scheme is not working as intended

AusNet supports the objective of the Market Impact Component (MIC) scheme. We recognise that there is value in asking TNSPs, by way of incentive, to balance the wholesale market price impact when planning and managing network outages to deliver against critical customer outcomes (reliability; efficiency, system security and new generation connection capacity to meet requirements of the energy transition).

In its Issues Paper, AER has identified desirable TNSP 'behaviours' that would minimise price impact from network outages: (1) plan for least impactful time; (2) coordinate where multiple network elements are affected; (3) re-schedule where new market impacts emerge; (4) adopt different procedures like 'in-service working'; and (5) notify market participants ahead of time.

However, AusNet considers that scheme, in its current form, is not working as intended to reasonably incentivise above behaviours. To assist, we highlight key issues in this submission, to which a workable arrangement should address. Most have been raised in past AER consultations, but during the period of a stable and predictable energy system rather than in a transition phase as is today. The MIC scheme:

1. Sets an unrealistic historical 'baseline' to project future expected TNSP performance;
2. Relies on a measurement approach that is becoming less reliable as a proxy for real-world price impact, in an energy system that will be more and more dependent on *highly variable* and *decentralised* renewables generation;
3. Assumes high capacity for the TNSP under current system conditions to materially respond or minimise disproportionate impact of the incentive;
4. Is administratively burdensome to operate, and unreasonably so; and
5. In Victoria, applies to a set of planned AEMO-initiated works beyond AusNet's reasonable control that results in unnecessary cost for Victorians.

1. Sets an unrealistic historical baseline to project expected TNSP performance

Current scheme assesses TNSP performance by comparing against the average of historical performance. Specifically, it uses the Marginal Cost of Constraints ('MCC') approach that assesses network constraints with a marginal impact of $10/MWh or more in a five-minute dispatch interval (DI)[1]. Annual total of these DIs is then compared to a historic target based on the average number of DIs incurred in five of the previous seven years.

Use of a historical baseline works best in an energy system that is mostly stable. While this approach has benefits of simplicity, it is unrealistic for a Victorian system that has changed substantively, and whose

[1] A $10/MWh event occurs when the difference between the bids of constrained off generators and the regional prices is equal to or greater than $10/MWh.

change is expected to accelerate further over next decade as coal retires. The AER has acknowledged this concern of using 'past performance' in the Issues Paper.

In brief, the key system changes are (1) high volumes of new zero-cost variable generation i.e. solar and wind, (2) that are connecting at diverse and decentralised locations; with a (3) substantive re-configuration of Victorian network to connect same; and (4) new types of system constraints needed to manage same renewables.

Firstly, the above heightens the volume and duration of generation likely to be affected (and hence volume of DIs calculated) by any planned network outage today compared to, say, 2017 – and this is further exacerbated by a Victorian system that is at its operational limits.

Over the last 5 years, the Victorian system has tripled utility solar and wind to 6.7GW (across new parts of network) compared to periods pre-2020[2] on which AusNet's STPIS MIC performance is assessed, while volumes of other generation (coal, hydro and gas) have not changed. This is the system environment in which almost all TNSPs are incurring maximum penalties.

Secondly, the pace of change will, and is required to, accelerate to replace retiring coal over the next decade. It will not be helpful to assume that the 'historical assessment' approach will 'catch-up' in a timely manner, and act as a 'fair' statistical representation of expected marginal price impacts from network outages under a future Victorian system. That is, the baseline will permanently change.

For example, under Draft Integrated System Plan (ISP) 2024, Victoria will have a substantially different system in 2032 than today. AEMO forecasts Victorian solar and wind renewables doubling to 11GW by 2032, while making substantial reconfiguration of the network and its flows[3].

Thirdly, setting an inappropriate baseline creates an unhelpful disincentive to TNSPs undertaking the very capital upgrades intended to alleviate connection constraints or to allow more generation connections.

For example, in 2022, AusNet incurred 5,960 DIs (almost all included DIs in 2022) due to works necessary to complete AEMO's VNI East Upgrade Project. This is a non-contestable AEMO-initiated project which increases network capacity, allowing for more energy to be transferred and shared between Victoria and New South Wales. With the looming closure of the Liddell Power Station in NSW and Yallourn Power Station in Victoria, this increased capacity provides significant market benefits for consumers, and was not in their long-term interests to delay the outages required to deliver this critical project.

2. Measurement approach is becoming less reliable as proxy for price impact, and this impacts costs for customers

The MCC measure is intended as an 'approximation' of price impact, that is, it assumes all constrained bids will materialise as actual impact to the regional price. While this may be more likely for inter-regional

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2 Median annual average of ~1.7GW of capacity between 2014 and 2020, based on existing generation capacity reported by AEMO Generation Info reports.

3 Key actionable ISP and VicGrid projects include MarinusLink, VNI-West, Western Renewables, Gippsland, and yet-to-be defined set of renewable energy zone investments in Victorian region

congestion[4], the scheme, by design, also picks up intra-regional congestion of new renewables (representing 40% of Victorian capacity and fastest growing set).

However, for intra-regional congestion, the impact of renewables generator's bid on final regional price is less certain – and depends on alternative available supply and pricing offered in that region.

In a system with high penetration and high volumes of zero-cost renewables located in diverse locations (as mentioned above), the opportunity to substitute is more likely. Also, renewables generation today are typically 'price takers', with dispatchable generation more likely to set price. Hence, we believe that the current approach captures more intra-regional congestion that does not result in a price impact, a trend that will accelerate as more connect.

In this scenario, we consider this creates high risk of unnecessary operational planning trade-offs, and increases costs for customers when TNSPs then act to minimise anticipated MIC impacts (for example, rescheduling outages increases operational costs of the network provider).

This limitation can be managed in different ways by the scheme. We recommend further work to clarify how scheme might more reasonably target congestion that produce a price impact – and provide a sustainable model for a future energy system primarily driven by such zero-cost generation.

3. Assumes high capacity for the TNSP under current system conditions to materially respond or minimise disproportionate impact of the incentive

AusNet does not believe that MIC penalties and rewards are proportionate to AusNet's capacity to respond, nor reflective of the costs of TNSP 'choices'. This is driven by:

- Lack of downtime for renewables, compared to traditional thermal generation, that offer few options to avoid 'proxy' market impact calculated by scheme;
- Growing unpredictability of 'net demand' and weather-driven availability of supply that reduces practical time to plan ahead; and
- An already constrained Victorian network and an increasing set of new technical constraints that reduce options to minimise network impact.

Reduced options to minimise impact for new renewables with few windows

In past, our operational planning protocols could seek to plan around windows based on scheduled downtime for thermal generation communicated to TNSPs. Solar and wind renewables offer few obvious comparable windows for Networks seeking to take an outage and minimise disruption.

Given substantive outage restrictions set for summer (driven by bushfire and high demand security concerns) and shoulder periods (due to minimum demand concerns), remaining periods with notional minimal price disruption is night or winter – both which introduce other operational delivery considerations. Simply put, some disruption will be necessary for these renewables but this consideration is

4 AER considered MCC as a 'high quality indicator' for inter-regional constraints as marginal value is typically the price difference between importing and exporting regions. AER Decision, 'Indicators of the market impact of transmission congestion', June 2006

not reflected by the use of historical baseline for outages (that embeds a much lower penetration of such generation – as mentioned previously)

Reduced time to plan ahead from unpredictability of net demand, and on weather for supply availability

'Net demand' sets the basis on which system conditions on the day are forecasted – and informs the likelihood of constraints binding and size of its disruption on the electricity market.

In past, AusNet could rely on studies based on possible network configurations, system generation operations and underlying demand requirements to plan outage slots that offered least market disruption, and most likely to remain so closer to identified time.

However, weather (like cloud cover or wind speeds) and the increased uptake of distributed generation (1) increases the complexity and risk in accurately forecasting localised net demand, and the opportunity to plan outages with minimal disruption; and (2) increases frequency of forecast conditions changing close to the day and time of a planned outage.

Hence, we have moved away from a model based on historical data, which forecasts windows of time when an outage may be taken on an asset without incurring MIC penalties, and instead rely on short term weather forecasts as the most practical indication of how the market will respond to an outage. We are seeing higher frequency of outages being cancelled on the day (often with an hour's notice rather than preferred two days), to avoid anticipated MIC penalties. Under our supplier contracts, the last-minute nature of these cancellations means AusNet is liable for the full cost of the cancelled works.

These are wasted costs, ultimately borne by customers, and highlights (1) reduced capacity of TNSP to accurately plan ahead under current system conditions, and (2) importance of the MIC measurement approach accurately targeting congestion with real-world price impact.

This inability to strategically plan outages in advance also impact generators who, when notified of an outage may purchase 'caps' or 'swaps' to meet their generation obligations, which would be impacted by the outage. If the outage is then rescheduled in order for the TNSP to avoid MIC impacts, this is a wasted expense which the generators cannot recover from the TNSP.

Reduced options to minimise impact from an already constrained Victorian network and increasing set of technical constraints

It is well recognised that AEMO and TNSPs are now required to address a wider range of new and emerging technical constraints binding under a wider range of scenarios – system strength, voltage collapse, voltage oscillation, etc

In addition, the Victorian network is highly constrained – to which AEMO and VicGrid are developing new project upgrades to deliver new network capacity (principally to connect new generation). During this period, however, AusNet's planned works are disproportionately exposed under this scheme to binding constraints driven by Victorian system limitation.

For example, the VNI-NSW path is a critical interconnector – and we anticipate that a network outage costs, on average, $0.35M per day – primarily due to constraints expected to bind consistently on this path over 12 hours in a day.

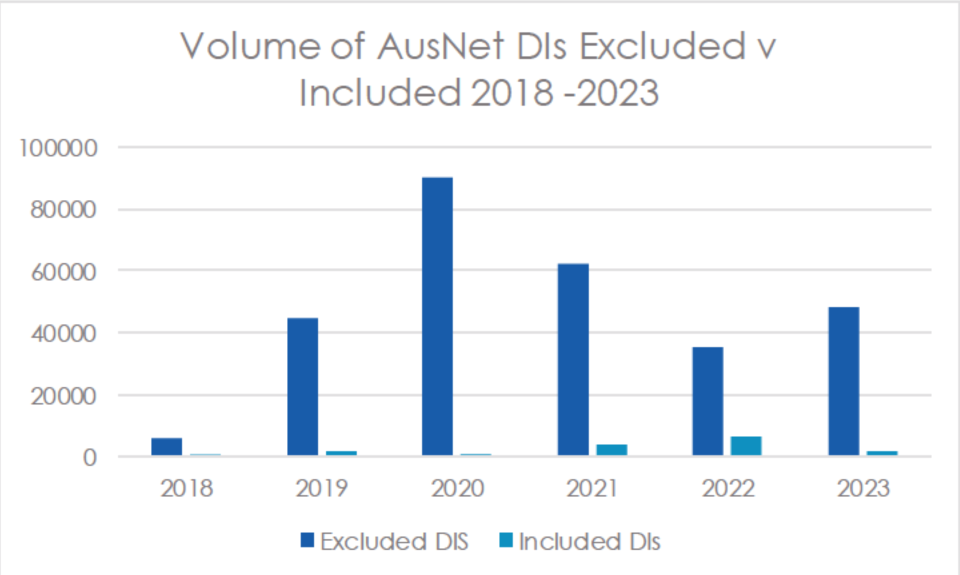
While arguable as the correct application of the incentive scheme, this also:

- Means that AusNet can quickly reach its maximum penalty in a few days, and this removes the notional effectiveness of this scheme for the rest of the year; and
- Assumes AusNet had recourse to alternative options to conduct works that would have better minimised the impact. This was not the case for the VNI-East project, mentioned above.

4. Administratively burdensome to operate

There are currently 13 grounds for a TNSP to exclude a DI from the yearly total. In order to secure an exemption for a DI, the TNSP must tag it with the relevant outage code and attach evidence to this effect, which the AER then reviews.

AusNet's volume of excluded DIs greatly dwarfs those included in the final reward/penalty calculation. As an example, the chart below shows a comparison of AusNet's included and excluded DIs over the previous five years.



Reporting DIs and exclusions place an exceptionally high administrative burden on TNSP and the AER that results in cost for consumers.

We believe this reinforces the importance of ensuring the current measurement approach is productive in reasonably achieving scheme objectives, and exploring options to improve measurement efficiency.

5. In Victoria, applies to AEMO-initiated non-contestable works beyond AusNet's reasonable control

The current MIC allows exclusions for contestable augmentations planned by AEMO Victoria, irrespective of the winning tenderer (including if it were AusNet)[5]. The decision explains that:

- The Victorian independent planning framework (whereby AEMO initiates all upgrades – contestable or non-contestable) has been designed to create 'efficiency' and should be recognised by the STPIS scheme; and
- TNSP 'control' over the asset and project is a major indicator in deciding whether a STPIS exclusion or inclusion is warranted.

AusNet believes this exclusion should extend to delivering non-contestable augmentations initiated by AEMO.

Firstly, in similar way for contestable augmentations, AEMO, acting as the Victorian planner, decides on the timing, number and nature of these works, not AusNet. Prior to assets being in-service, AusNet has no planning or operational control over these assets. Also, prior to regulated asset roll-in at the next Transmission Revenue Review, these projects are not funded by a revenue determination.

Secondly, AEMO has agreed to contractual mechanisms for these AEMO-initiated non-contestable projects that offset negative MIC impact from undertaking these works. The effective outcomes of this arrangement are (1) to treat these projects as excluded – on basis that AEMO has planning control; and (2) is cost neutral for Victorian consumers – as any offsets are recovered by AEMO from customers.

For these reasons, AusNet requests that AER excludes these non-contestable augmentations from MIC calculation. This removes the administrative burden for AusNet and AEMO required to operate this contractual mechanism – and avoids unnecessary costs for customers.

As an example, inclusion of AEMO-initiated projects in AusNet's MIC calculations for the 2022- 2023 period has resulted in an additional 6,482 DIs included in AusNet's yearly totals.

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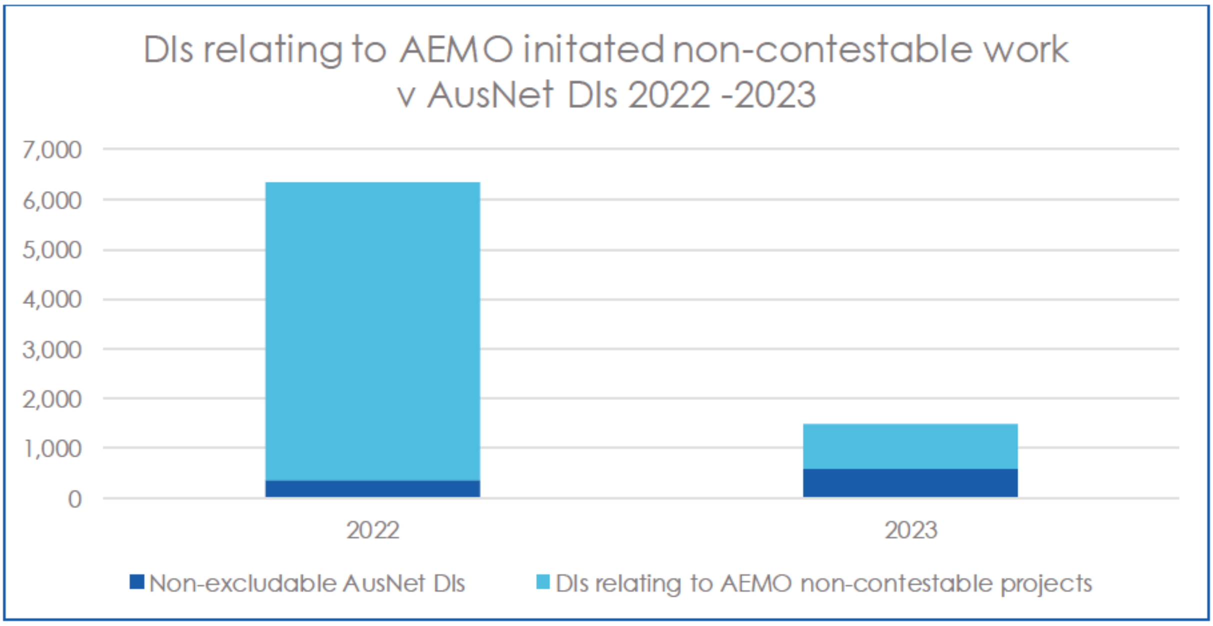
5 p33 of AER Decision, STPIS Version 5, Sep 2015



The cost of which, will ultimately be borne by customers.

Alternative MIC options proposed do not practically address issues raised

In deciding on an alternative scheme, we acknowledge this assessment is best made against established regulatory design criteria (and as referenced in original 2007 consultation)[6] – that any scheme should:

- Promote the NEM objective;
- Relate the economic benefit of the TNSP's action to the cost;
- Depend, as far as possible, on the TNSP's action;
- Constructed on objective information and analysis that can be audited;
- Apply consistently across TNSPs; and
- Minimise administrative costs.

We do not see proposed options offer substantive or obvious remedies to the issues raised:

- 'Transparency-only' reporting depends on clarifying relevant objective, measure and operable guidelines;
- 'Revising performance targets' adds little value when the measure and baseline used are unrepresentative; and
- 'Better targeting rewards and penalties' depends on finding objective, practicable and efficient ways to address complexities associated with targeting specific MIC events. The Issue Paper suggests this is likely costly and difficult to implement.

We support further work to develop a workable and sustainable scheme, but failing this, we believe it be either suspended or transitioned to a 'transparency-only' scheme.

The Network Capability Component (NCC) remains relevant and has incentive value in the long-term

We support the NCC scheme; and it has incentive value for AusNet.

- Our customers can only benefit from schemes that promotes search for 'low-cost' opportunities to maximise network capabilities that result in additional market benefits for customers;
- While established networks may be argued to have less potential to benefit from previous improvements, we expect this to change as all networks will undergo major transformation and reconfiguration – as part of energy transition to renewables;
- The NCC allows for flexibility as TNSPs may add or remove projects during the TRR period in response to market conditions. This provides us with an effective mechanism to rapidly respond to emerging market constraints which may arise during the energy transition. and
- We do not consider that this scheme creates unnecessary administrative burden or complexity for our planners.

In extension to this, we believe there is an opportunity to alleviate the administrative burden identified by the AER's issue paper and deliver further benefits to customers by broadening definition used by incentive scheme to extend to projects that deliver market benefit by:

- Enhancing 'operating' capability of the network, not simply the theoretical physical capability;
- Enhancing system security and network availability for credible and non-credible contingencies; or
- Raising total network capacity or remove network limitations.

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[6] Final (aer.gov.au) pg 20 – 21.

We have identified NCIPAP projects in past to which AEMO and AER have agreed would deliver market benefits, but did not technically meet the parameters of the scheme. The NCIPAP scheme requires projects be linked to the capacity of individual connection points of the network, and assessed based on:

- Identifying the key network capability limitations on each transmission circuit or load injection point on its network and
- Identifying the target capacity to which the project endeavours to achieve e.g 'the market benefit' of the project.

These projects are assessed based not only on the market benefit, but also how closely they fit within the narrow technical definition of the scheme (i.e. requiring projects to increase the capacity of individual connection points).

One example of above relates to an AusNet proposal in 2021/22 to upgrade the network's Under Frequency Load Shedding (UFLS) capabilities.

Under Frequency Load Shedding (UFLS) involves the automatic disconnection of customer loads during a severe under-frequency event. Frequency relays are installed at load circuits, with varying trip settings, designed to progressively disconnect loads in a controlled manner to arrest the frequency decline. As per NER requirements, the amount of net load available for shedding under the UFLS should be adequate to arrest the impacts of a range of significant multiple contingency events, affecting up to 60% of the total power system load (NER clause 4.3.1(k)). In their analysis, AEMO has found that the net load in the Victorian UFLS scheme is decreasing below this requirement in periods with high levels of distributed PV operating, and this trend is likely to continue over the coming years. This means that at times the power system is operating without the intended safety measures, placing customers and the network at unacceptable risk.

The analysis shows that the annual minimum net UFLS load measured in the Victorian UFLS scheme has been declining over the past few years, from 1,926 MW in 2018 to 1,273 in 2020. This is forecasted continue, with the report predicting a minimum UFLS load to reach as low as 1,028 MW by late 2021, and 499 MW by late 2023. The total net UFLS load as a percentage of the total underlying load in Victoria for the 2020 historical year remained above the 60% value indicated in the NER for periods with no DPV generating. However, in periods of high DPV generation, this reached below 50% for more than half the time and in some periods as low as 30%. By 2023, this is forecasted to fall below 60% for almost 40% of the time and reach a minimum of 12%.

These results indicate that effectiveness of UFLS in Victoria is being significantly impacted by DPV (particularly during high generation periods) and the connection of large generating units into UFLS circuits. An ineffective UFLS scheme that has insufficient net load available to trip to arrest a severe frequency decline, or one that compounds the effect of under-frequency disturbances by tripping a circuit operating in reverse power flow could even result in system black.

AusNet proposed to spend $2.8M adding additional feeders into the existing UFLS relays and adjusting protection settings. It is projected that this project would deliver $22.3M in market benefits per annum due to reduced unserved energy and improved reliability/security.

While both AEMO and the AER agreed with this assessment of market benefits, the project was not accepted as the AER believed it did not fit within the definition of the scheme.

We believe the narrow definition of the scheme is an unnecessary barrier to delivering benefits to customers. Broadening the definition will also remove the requirement for the AER to assess the existing capability at a given point in a transmission network and the strategies network propose to alleviate this.

If you have any questions regarding this submission, you can contact me by email at [redacted]

Sincerely,

[redacted]

Jack San,
Manager, Energy Policy
AusNet