ELECTRICITY NETWORK REGULATION REVIEW PACKAGE 1

CONSULTATION PAPER

1. Executive summary

CitiPower, Powercor and United Energy (**CPU**) support the Australian Energy Market Commission's (**AEMC**) review of electricity network regulation.

Broadly, when considering reforms, we encourage the AEMC to be guided by demonstrated customer outcomes, market efficiency and evidence-based regulation. The primary assessment criterion, therefore, should be the long-term interests of consumers, including equitable participation in the energy transition.

More specifically, we consider the greatest reform priorities are service classification arrangements, recognition of the DSO role, improving joint planning processes and addressing competition concerns in transmission connection services. We also support greater distributor participation in emerging markets, including EVCI, where this demonstrably benefits customers and appropriate safeguards remain in place.

We summarise these considerations below and discuss each in detail in our submission.

The service classification framework, not ring-fencing, is the issue requiring reform

Current debates have incorrectly framed issues as ring-fencing problems. The issue is the service classification framework has not evolved to accommodate emerging services. Service classification decisions should be decoupled from the regulatory cycle and replaced with an agile public process allowing classification reviews when new services emerge.

Distributors should be allowed to contribute to emerging markets where customer benefits can be demonstrated

Distributors can create significant whole-of-system benefits through their visibility of local network conditions and customer energy resources (CER). Participation in contestable markets should not be prohibited where adequate controls are in place.

DSO functions should be supported through incentives

Incentive-based frameworks are preferable to rigid prescriptive requirements. International experience demonstrates that incentives can achieve separation and transparency objectives at lower cost than detailed prescriptive requirements.

Joint transmission-distribution planning is producing poor outcomes and requires reform

We have significant concerns with the current Victorian joint planning arrangements. They have been heavily weighted toward transmission solutions and lack clear accountability.

Existing distribution ring-fencing arrangements are working effectively

No material breaches of the ring-fencing framework have been identified since their inception demonstrating existing controls and reporting have been effective in preventing cross-subsidisation and discriminatory conduct.

Transmission connection arrangements present significant competition concerns

Transmission connection processes are acting as a barrier to efficient competition and investment through excessive pricing and long delivery and offer preparation timeframes.

Cost allocation and shared asset frameworks remain fit for purpose

The current arrangements have protected customers from cross subsidies, encouraged efficient asset utilisation and have shared benefits with distribution customers.

We oppose Nexa's proposed rule changes

No evidence has been presented of systemic failures under the current framework. Further elevation of operational ring-fencing requirements into the National Electricity Rules (Rules) reduces flexibility, increases compliance costs and imposes unnecessary regulatory burden.

We support the Energy Network Association's (ENA) proposal for distributor-led EV charging infrastructure (EVCI)

It addresses the current "chicken and egg" challenge that has limited EV adoption and would allow delivery of EVCI faster and at a lower cost.

2. What network services should be subject to economic regulation and are changes to the service classification framework required?

Since establishment of the *National Electricity Rules* (**Rules**), the energy sector has undergone marked change. The roles and functions of market participants that was once largely static has become highly dynamic, challenging the rigidity of the service classification process.

2.1 Service classification

New opportunities are rapidly emerging, with markets participants keen to get a foothold in these emerging markets.

Distributors can play an important role in these rapidly evolving markets. For example, ancillary service markets largely prohibit distributor participation despite their ability to provide voltage support, reactive power services, congestion management, system strength services, frequency support, operating reserves and restoration and resilience services.

Many of these markets are characterised by few or a single service provider which has been to detriment of customers.

2.1.1 Changes to service classification arrangements

The wider debate around the ring fencing framework is better characterised as issues with the rigidity of the service classification framework. As new services are emerging, but not facilitated through the service classification framework, distributors must seek the ability to provide these services under waivers or negotiated services. Therefore it is not the ring fencing framework that requires reform but rather the service classification arrangements not evolving to reflect the dynamic nature of the energy transition.

The current service classification arrangements are no longer fit for purpose. The period between regulatory cycles is not frequent enough to manage the growth in new and emerging services. A more agile process is required. That requires a decoupling of the existing arrangements that link service classification to the framework and approach (**F&A**) process. Service classification should rather be subject to a review process when the AER receives a request to add or delete a service. The process should be public with a requirement for a decision within 6 months of the request being lodged.

2.1.2 Benefits of distribution involvement

Distributor involvement can unlock whole of system efficiencies or the 'value stack'. Siloed approaches limit the value that can be unlocked, resulting in customers receiving proportionately less benefit than they otherwise could. For example, distributors sit closest to millions of customer energy resources (**CER**) and have the visibility, especially in Victoria, to identify lower cost alternatives to further network augmentation or new generation capacity. Distributors can improve utilisation of CER assets, lowering costs for all market participants including customers. Similarly, distributors have the most granular understanding of transformer loadings, feeder congestion, voltage issues and local reliability risks. This understanding can contribute to further unlocking whole of system benefits.

The same stakeholders are arguing active participation by distributors in contestable markets 'crowds out' other market participants. Theoretically in a situation with no controls on a distributor's behaviour this could occur, but this is not the framework under the Rules. The Rules mandate a rigorous ring fencing regime and extensive regulatory reporting to the Australian Energy Regulator (**AER**). What therefore should be under consideration is whether distribution involvement in contestable markets can lead to lower charges and better service for customers.

Distributor involvement in contestable markets (with controls) increases competition. Competition is important as many emerging markets are nascent and serviced by small numbers of service providers or in some cases, no service provider at all e.g. EV charging infrastructure (**EVCI**) in rural and regional areas. Distributors can provide an alternative option (or only option in some areas) in these markets that benefit customers. For example, based on our EVCI trials we are seeing energy charges as low as 21 cents/kWh under a model where multiple e-mobility service providers (**eMSPs**) compete at the point of supply, compared to 50 cents/kWh at some market-led sites where no competition is occurring.

Distribution customers also benefit through economies of scale and scope or alternately, unregulated revenues that offset some of the regulated revenues through the shared asset framework.

Therefore, provided there are controls (and there are), clear cost allocations, reporting of unregulated revenues and transparent provision of information, distribution participation in new emerging contestable markets can be in the long-term interests of consumers. Where a distributor is participating in a contestable market, it should be required to report on costs and revenues to the AER. This is consistent with the requirements of the kerbside EVCI charging waiver granted to CPU.

2.2 Distribution system operator

Harnessing CER is critical and its value is maximised when effectively integrated into energy markets. The importance of the distribution system operators (**DSO**) cannot be understated in ensuring CER value is maximised.

Our networks already perform most of the functions identified as DSO responsibilities, supported by advanced operational systems and more than 15 years of smart meter penetration across our networks. More can be achieved, but the current regulatory framework does not recognise many DSO functions as distributor responsibilities. The Rules need to clarify, and incentive framework modified, to reflect these new DSO responsibilities.

Penetration of CER across distribution networks will be limited by the physical constraints of individual networks, and their need to maintain compliance, safety and stability. These challenges require constant attention and will become more challenging over time. Without a stable, efficient and reliable network, market optimisation of CER is not possible.

Harnessing and maximising the value of CER is about more than a DSO. Our customers have consistently demonstrated a reticence to cede control of their CER to third parties. Partially this is due to the absence of robust contractual and customer protection frameworks. Installed CER may also not be compliant with Australian standards, such as AS4777 power quality standards. This is to the detriment of customers, their neighbours, and the local distribution network. This is reflective of the failure to regulate CER installers and providers. These issues need to be tackled if the value of CER is to be maximised. The DSO has an important role in this in terms of its access to information.

2.2.1 Accommodating the DSO role for DNSPs

The AEMC has a choice in regulating DSO activities. Whilst some stakeholders will seek promote the need for highly prescriptive rules, we believe the use of incentives is the superior option to align DSO services with new, identified and emerging customer needs and address conflicts that may arise between the DSO and distribution network operator (**DNO**).

The prescriptive approach adopted in the *Distribution Ring Fencing Guideline* (**Guideline**) has not served distribution customers well. It was implemented without consideration of the different structures and operating environments under which individual distributors operated. It is a ‘one size fit all’ approach that necessitated enormous system, process and organisational change. This is ultimately paid for by distribution customers. The same outcome could have been achieved by permitting each distributor to determine its own process and organisational changes to achieve an equivalent level of controls at a lower cost to distribution customers.

The flexibility to adopt individual business processes and structures has been adopted in the United Kingdom's separation of DSO-DNO activities. Each distributor has the flexibility to achieve separation of its DSO-DNO activities in a least cost manner. Incentives were used to ensure each distributor achieved an equivalent level of controls. An incentives approach has arguable delivered a lower cost transition for distribution customers, but also, allowed distributors to optimise management of DSO-DNO relationship. The current Guideline severely limits interaction between distributors and affiliates. Such an outcome can't be the case for the DSO-DNO relationship given their joint reliance on common data and systems to perform their functions. There is also an inextricable link between DSO functions and DNO accountabilities e.g. service target performance incentive scheme (**STPIS**).

2.2.2 Stakeholder concerns with DSO conflicts

A review of stakeholder submissions from the Department of Climate Change Energy Environment and Water (**DCCEEW**) 2025 consultation *Redefining roles and responsibilities for power system and market operations in a high CER future,* identifies three concerns. These included concerns with investment bias, consideration of wholesale market benefits and the data access and transparency.

For the reasons outlined below, we consider these concerns are overstated and/or can be effectively managed with appropriate incentives or controls.

Capital investment bias

It is argued distributors prefer network solutions based on shareholder's preference for regulatory asset base (**RAB**) growth. This cannot be true for privately owned distributors.

Given the capital nature of networks, shareholders of private owned distributors must be focused on cashflow and credit metrics. Large capital investments can be detrimental to these metrics, involving debt raising and long asset lives. Large capital investments are risky, especially in a rapidly evolving energy markets where asset stranding is a real risk.

Regulatory disciplines temper capital investment. Any capital investment greater than $7M is subject to the *regulatory investment test* (**RIT**). The RIT involves publication of multiple public reports and an open tender process. Capital investment forecast and actual capital expenditure is forensically scrutinised through regulatory reset processes, often involving external engineering review. The effectiveness of these regulatory disciplines is evidenced in our networks being amongst the most highly utilised in the NEM.

Alternatives to network capital investments are commonly referred to as non-network solutions (**NNS**). The opportunities for NNS below $7M are identified, and procured, at the distributor's discretion. Distributors are incentivised to procure non-network solutions through the demand management incentive scheme (**DMIS**). DMIS subsidises the cost of NNS by up to 50 per cent provided the NNS is cost efficient and fit for purpose.

The firmness, or ability of a NNS to deliver the contracted response, is crucial, as well as the transaction terms in ensuring risk of non-deliverability is not borne by customers. Similarly, the firmness of NNS is essential to avoid over procurement of NNS. The more parties introduced (e.g. via externally hosted marketplace or industry data hubs) increases the risk of NNS not being delivered and magnifies uncertainty as to who is the responsible party if a NNS fails to deliver.

In practice, our networks operate an on-line market portal (**Piclo Flex**) to publicise network constraints to potential NNS providers. Piclo Flex provides opportunities for small and large NSS providers to offer services that address low voltage and high voltage constraints. It is also more than a marketplace, providing NNS proponents access to network constraint data down to the LV network.

Since its launch, Piclo Flex has advertised more than 200 opportunities across our networks. Currently we are seeking 560 MW of NNS through Piclo Flex.

Fostering development of a NNS market, however, requires time. This is consistent with the experience in the United Kingdom. Exploration of opportunities to further deepen the market for NNS will continue to evolve with consideration of contract terms, service target performance incentive scheme (**STPIS**) holidays and contract tenure. These opportunities are worthy of consideration as a mature NNS marketplace has the potential to improve network utilisation and lower costs for customers. Notwithstanding this, we expect to defer $2.8M in augmentation over the next 5 years through non-network solutions.

Further changes could also support growth in NSS utilisation. These include:

- proactively scoping out the operating requirements with NSS proponents to balance outcomes between NSS and network augmentation
- having transparency on the NNS tender process such as clear publication of the results, which could be expanded to include market benefits
- removing NNS contract stranding risk by the AER facilitating longer term agreements
- independent verification of the process and decisions in selecting NSS
- introduction of a CER tariff with seasonality to encourage behavioural demand response
- changes to the DMIS to increase the flexibility in applicability and remove associated risks with NNS
- having more incentives introduced for DSNP's to recover funding from non-network solution expenditure and procurement and to develop the NNS market
- applying exclusions to schemes such as STPIS and GSL for non-performance of NNS to reduce the risk profile for DSOs
- permit over procurement of NNS beyond the constraint (particularly as flexibility markets are in their infancy in Australia). This would enable distributors to diversify the risk of NNS non-performance and provide redundancy in the event an NNS provider fails to deliver when required. A variation of this would be a 'shared risk fund' between NSS providers.

Wholesale market consideration

More than 95 per cent of our customers can connect and export their excess solar into the market. Renewable generation has grown on the CitiPower/Powercor networks from 2.06GW in 2019 to 3.90GW in 2025. Through the implementation of smart meter technology and data analytics, dynamic voltage management systems (**DVMS**), LV and HV distributed energy resource management (**DERMS**), more than 500MW of capacity has been unlocked.

Wholesale market and network requirements are, for the most part, aligned. For example, excessive solar exports drive negative wholesale market prices whilst creating grid instability due to minimum load. However energy supply is essential, and for most customers, their focus is a reliable, safe and resilient supply. Further for wholesale market participants, energy markets simply will not work if the underlying network has failed. A reliable network is the foundation of the wholesale market.

Can the wholesale market and network requirements be more closely aligned? Yes, but strengthening these incentives should not compromise network reliability, safety or resilience. Victoria has experienced rapid growth in CER resources. Unfortunately the associated customer protection, legal and installation frameworks have lagged this growth. A robust customer protection and compliance framework is critical if CER is to be seamlessly integrated without compromising network stability.

An area that's limits consideration of wholesale market benefits is the requirement to use the AER's customer export curtailment values (**CECVs**). The CECV is intended to represent the detriment to all customers from the curtailment of exports from CER due to network limitations. Distributors are required to quantify the value of the export curtailment that is expected to be alleviated by a proposal (such as increasing CER hosting capacity) and to economically justify an investment on this basis. The CECV is a poor proxy for wholesale market benefits. In particular, the CECV excludes the benefits of avoided generation capacity investment which results in the CECV being systematically underestimated. This can lead to inefficient investment decisions and increased electricity costs for customers.

Incentives can be used to reinforce consideration of the wholesale market. This could include utilisation measures for different network levels. This would need to consider existing utilisation which differs widely between distributors. We have already voluntarily committed to minimising curtailment of customer exports. For example, CitiPower is committed to allowing 95 per cent of customers to freely export 99 per cent of the time and Powercor and United Energy allowing 90 per cent of customers to freely export 99 per cent of the time. Other possible incentives include management of planned outages, network availability measures or forecasting accuracy of constraints.

Data access and transparency

Data access and transparency can be managed utilising data availability incentives, provision of real time visibility metrics or availability of customer facing systems.

The incentive regime for DSOs in the United Kingdom is based on surveys completed by customers/stakeholders and external experts. There is merit in surveys given assessment is completed by actual users of DSO functions. The assessments could be supported through bi-annual reporting of actual and forecast DSO performance metrics, including the wholesale markets benefits generated via DSO activities.

The extremely fast paced policy environment and rapidly evolving technical changes require the DSO to be more agile and nimble. Five yearly regulatory cycles are ill equipped to facilitate agility.

To address this, consideration should be given to a nominated DSO pass through under the Rules based on fixed 0.5 per cent materiality threshold. This reform would recognise the rapidly evolving requirements DSOs are required to meet, lower distributor funding concerns and allow faster implementation of policy changes and technical developments that promote CER development.

2.3 Efficient and effective coordination

A key aspect of efficient and effective coordination is the interface with the system planner.

Clause 5.14.1 of the Rules requires the system planner and distributors to jointly assess network adequacy and plan future investments together. This is to ensure network limitations and constraints are identified and ensure coordinated and efficient solutions are developed across the transmission and distribution networks.

The system planner for Victoria is VicGrid. Their role is to ensure joint planning occurs and transmission, distribution and connection planning are aligned. The Rule obligations are around joint planning are however high level and process based. This has led to poor outcomes for Victorian customers.

For example, the current arrangements refer loosely to ‘best endeavours’ and ‘working together’. There is no requirement to make formal comparisons of transmission and distribution options such as a quantified cost-benefit testing (like a RIT would require).

Further, where a distribution option was considered, there is no evidence they were considered in an unbiased manner. There is no explicit ‘distribution first’ or ‘non-network first’ test as required under a RIT or any explicit documentation. The result is a transmission solution dominated network.

The consequences are rising transmission costs and an absence of network capacity to fast track the energy transition.

To address these limitations, reform is required to make joint planning more effective. Reform options for consideration include:

- requiring a formal ‘options assessment framework’ that assesses transmission, distribution and NSS applying a consistent criteria ensuring an ‘efficient outcome’ is real and demonstrable
- a new mandatory ‘distribution alternative test’ that documents whether a distribution or hybrid solution could defer, reduce or avoid the need for transmission augmentation. Distributors should be able to submit options and the system planner assess and respond to them

- require early-stage joint problem definition agreement before solutions are identified. The system planner should jointly define constraints and demand assumptions with distributors ensuring transmission framing does not emerge from the beginning
- for each transmission augmentation, the system planner publishes the options considered (including distribution), any assumptions and the reasons for rejecting alternatives aiding system planner accountability and discipline
- require assessment whether a combination of smaller transmission upgrades and a distribution option could be more efficient than a standalone transmission augmentation avoiding binary transmission vs distribution thinking
- a greater role for the AER in monitoring the compliance with Rule based joint planning requirements. Monitoring would not extend to dispute resolution as AER intervention could be achieved in a sufficiently timely manner to be effective
- lastly, where a material decision is involved, the system planner engage an independent review to ensure there is no risk of one-sided assessments.

3. Are changes required to the ring-fencing arrangements?

The current ring fencing arrangements have proven highly effective in preventing cross subsidisation and discriminatory behaviour. Between Guideline and RIO reporting requirements, no material breaches have been identified since the Guideline's inception. Where minor breaches have been identified, most have been voluntarily identified by the distributor.

Moreover, to our knowledge, there has been no identified instances of distributors distorting competition in contestable markets in which their affiliates compete.

Nevertheless, the ring fencing controls have not been costless. Restrictions on systems, processes and resource movement has resulted in additional costs and lower productivity through reduced synergies. In the absence of material breaches, there would need to be compelling evidence or data to justify imposition of further restrictions. This is not evident to us. Further, the energy transition of itself is not justification for further ring fencing controls. Given the costs of ring fencing controls, we should not be guessing how markets and services may evolve under the energy transition but rather act only if evidence supports an issue.

Having said that, the current waiver process is not ideal. It can be slow, bureaucratic and opaque. Therefore, there is merit in reforming the process, but the Rules are not the best place for this. Reform of waiver processes is best considered as part of a Guideline review process.

4. Are changes required to the connection and/or facility access arrangements?

Overall, we consider distribution connection access, and facilities access arrangements are being effectively regulated. However, the same cannot be said for transmission connection access.

4.1 Distribution connection access

Distribution connection access is highly regulated.

For example, most distribution connections proceed under Chapter 5A of the Rules, requiring application of an AER approved connection policy consistent with the *Connection Charging Guideline*. The *Connection Charging Guidelines* prescribe how an offer must be prepared for a connecting customer, the assumptions underlying that offer, and the timeframes in which the offer must be made.

A small number of connection applications are processed under Chapter 5 of the Rules. Connection applications under Chapter 5 involve very large loads (30MW and above) and highly sophisticated connection applicants. We are not aware of any of these connection applicants approaching the AER in relation to a connection offer from our networks.

4.2 Transmission connection access

The work we require from a declared transmission system operator (**DTSO**) varies, depending on the connection and the terminal station. It can include 'cut-in' works, contestable augmentation works or non-contestable works. Examples include installation of new 66kV circuit breakers, constructing new 66kV switch bays or updating protection settings, communication systems or control settings.

The experience we have had is DTSOs routinely leveraging market power to incentivise connection proponents to bypass the distribution network through limiting our ability to compete with DTSOs. Also observed has been DTSOs seeking to hinder entry and/or otherwise lessen competition in the wholesale market. This is to benefit an unregulated affiliate that owns, operates or is developing a generation system and/or integrated resource system (e.g. grid-scale batteries).

We have significant concerns, therefore, in obtaining fair and reasonable access to the transmission network. This is to the detriment of large load and generation customers.

4.2.1 Unjustifiably high pricing of connection offers

Offers are regularly received that significantly exceed our estimate of what the work should cost to be completed. For example, in a scenario where a connection to our distribution network requires work at a terminal station, the DTSO's estimate to complete the required work can be double that of what it could cost our own business to complete.

Excessive pricing of offers impedes our ability to compete with the DTSO's offer for the same project. In many instances, a customer has a choice whether to connect to the distribution or transmission network. DTSOs can, and in our view do, leverage their position as the sole provider of transmission augmentation works at their terminal stations to incentivise customers to bypass the distribution network. Beyond the impact on the distribution network, the conduct increases the connection cost for any generation or integrated resource system proponent that chooses the distribution network for connection or chooses to compete in the wholesale market with affiliates of the DTSO.

4.2.2 Unacceptable delivery timeframes

Delivery timeframes for transmission connection works are frequently longer than our estimate for when the works should be completed. This occurs because DTSOs refuse to undertake work in a non-sequential order. In contrast, we undertake multiple project tasks together, shortening project timeframes. Delays in project timelines, and the commencement of commercialisation, materially impact the connection proponents investment case, sometimes to the extent the project is no longer commercially viable.

DTSOs have not provided us a valid reason for not undertaking works in a non-sequential order. In the absence of an explanation, it can only be concluded excessive delivery timeframes are another mechanism to render distribution connection offers uncompetitive or reduce the competitiveness of generation or integrated resource projects competing in the wholesale market.

4.2.3 Delays in preparing offers

There have been long delays between when an application for connection is lodged and an offer received. It can take years before a final connection offer is received.

Delaying offers has the same impact as project delays, impact investment cases and in some circumstances, rendering the project commercially unviable. This is a further mechanism utilised by DTSOs to render distribution connection offers uncompetitive.

4.2.4 Sharing of customer information between DTSOs and their unregulated affiliate

Information provided to the DTSO to support a distribution connection (i.e. in joint network planning meetings) has subsequently been utilised to enable an unregulated affiliate to provide an alternate offer to the connection proponent. This absence of meaningful functional separation requirements between the DTSO and its unregulated affiliate has made the practice acceptable.

In meetings with have had with DTSOs, we have found the same people often represent both the DTSO and the affiliate. The information gained from these meetings can be used to directly advance the interests of the unregulated affiliate. Access to information, combined with DTSOs' ability to render distribution offers less competitive, impact competition in supplying grid connection for large customers, to the detriment of large load and generation customers.

4.2.5 Capacity of transmission connection assets and land access at terminal stations

DTSOs have used space, and existing capacity of transmission connection assets, at their terminal station to develop unregulated connections for large loads or energy storage directly to the 66kV transmission connection infrastructure. This limits the capacity, and space, available for new assets required to connect, and supply, distribution customers. This practice escalates the cost for future distribution connections. In a worst case scenario, it may necessitate construction of a new terminal station. As DTSOs face limited competition for the construction of terminal stations, they are incentivised to utilise the space and capacity at existing terminal stations for their own connections, to enable them to charge distributors for construction of new terminal stations. The practice has also led to the unregulated affiliate benefiting from assets that have been largely funded by regulated transmission charges recovered from distribution customers.

4.2.6 Negotiate arbitrate framework

The consultation paper references the effectiveness of the ‘negotiate-arbitrate’ model.

For most connection proponents, and augmentation of the transmission system initiated by distributors, speed of connection is critical. In the case of a connection proponent, they face pressure to get their facility commercialised. For distributors, the concerns will relate to safety and reliability of the distribution network. Neither situation allows for protracted connection disputes.

An example relates to 2025 project where the AER was asked its views on the ‘fair and reasonableness’ of a transmission connection offer. Following an initial briefing, no further contact was received for a further 12 months. In the interim period, the connection offer had to be accepted to avoid the project no longer being viable. This illustrates the point that dispute resolution is a slow process that does not meet real world needs.

More broadly the conduct above has been highlighted to the AER, Australian Energy Market Operator (**AEMO**), VicGrid, the Australian Competition and Consumer Commission (**ACCC**), the AEMC and State and Federal Governments. None of these processes have resulted in change. This review presents an opportunity to make real change.

4.3 Facilities access arrangements

Prior to 1 July, all facilities access agreements (**FAA**) were unregulated. They were subject to negotiation between a network and the proponent seeking access to ducts or poles. The process was a negotiation, hence as expected from time to time there were differences of opinion on terms and conditions, but nothing for our networks that led to a dispute that required intervention. The overwhelming majority of these agreements involved large telecommunication companies.

Since 1 July, pole access in Victoria for EVCI access seekers has been classified as a negotiated service. As a result, there are now two FAA's, one for EVCI access seekers and one for all other pole or duct access seekers. The EVCI FAA is subject to an AER approved negotiating framework which allows for, in the event of a dispute, the AER to conduct a 'fair and reasonable' review.

The conversion of EVCI pole access to a negotiated service is very new. There has not been sufficient time to test whether the revised EVCI FAA meets the needs of EVCI proponents, or for its 'fair and reasonableness' to be tested by the AER. Therefore at this stage, there is not a compelling case for further regulatory action. This is better tested over a longer period such as five years.

5. Are changes required to the cost allocation and/or shared asset arrangements?

We do not consider there are material changes required to the cost allocation and shared asset arrangements.

Our cost allocation methodology (**CAM**) document clearly sets out how shared costs will be allocated between distribution services, while the AER's guideline on shared assets identifies how unregulated revenue earned from dual use assets will be shared with customers. We consider these arrangements continue to work in the interests of customers, who benefit from lower bills when material unregulated services are undertaken, while ensuring distributors are incentivised to deliver unregulated services where it is in the long-term interests of consumers.

In relation to community batteries and how they should be accounted for when making cost allocation decisions, these assets are a distinct asset type which can provide varying levels of regulated and unregulated services. Given this feature it is reasonable to have specific arrangements for this asset type when considering how costs are allocated. We support the current approach to allocating costs for community batteries, which limits the costs that can be added to the regulatory asset base to expected customer benefits. Limiting the amount of expenditure that can be added to the regulatory asset base ensures that customers pay no more than the benefit they are expected to receive. We also support the current methodology for calculating expected customer benefits, which relates to a defined list of benefits, and refers to forecast benefits from a single point in time to allocate costs.

We consider that cost allocation should not be revisited over time. Costs are allocated between regulated and unregulated services based on expected use of the asset at the time these services commence. This is the basis on which a distributor makes its investment decision and ensures that only the expected costs associated with providing regulated services are passed on to customers through the regulatory framework. There is no impact to standard control services should additional unregulated services be undertaken using the network asset in the future because standard control services are prioritised. If distributors were to be subjected to uncertain cost allocation adjustments it would significantly reduce incentives to invest in assets which can provide both standard control services and unregulated services to the benefit of consumers.

We note that our most recent published version of our CAM already includes negotiated services.[1] However, we do not consider the shared asset arrangements should be extended to negotiated services and should continue to relate to unregulated revenue.

The shared asset framework was introduced to protect standard control customers who have little ability to influence how network assets are used to provide unregulated services and are broadly captive through regulated tariffs. This is not the case for negotiated services which are already part of the regulatory framework and include:

- dispute resolution mechanisms
- pricing principles and
- negotiation frameworks approved by the AER.

Applying the shared asset guideline to negotiated services would effectively impose an additional regulatory overlay where the Rules already provide regulatory protections. The current arrangement ensures that distributors are incentivised to increase asset utilisation through efficient unregulated

[1] https://media.powercor.com.au/wp-content/uploads/2018/11/07103641/Powercor-Cost-Allocation-Method.pdf

revenue opportunities while ensuring customers receive a portion of the additional unregulated revenues.

6. Nexa rule change request - Do the ring-fencing arrangements in the NER need to be strengthened?

The Nexa Advisory (**Nexa**) proposal relies on three contentions:

- *ring-fencing protections have weakened over time*: they argue the number of waivers issued has grown and become 'normalised'
- *observational trend*: the number of waivers approved has been increased since 2022
- *policy interpretation*: the granted waivers contain insufficient conditions, monitoring or transparency.

Nexa relies on the underlying theory distributors can leverage regulated revenues, information asymmetry and control of network access to advance their position in contestable markets. They argue this leverage 'crowds out' investment, especially in emerging CER markets. The evidence to support these contentions is economic theory of monopolies leveraging into adjacent markets, stakeholder concerns and examples of activities permitted under waivers.

The underlying economic theory is not in contention. Neither is the need for controls to manage anti-competitive conduct. The reality is the Rules, and the AER, have created an environment in which controls do exist. The question therefore is whether the existing controls have proven effective. The available evidence suggests these controls have proven highly effective.

The Guideline, which contains most of the controls, was established in 2017. Since that time, we are not aware of any prosecutions or material breaches identified of the controls. Of the breaches that have occurred, the majority are administrative or process related or inadvertent provision of services outside of the regulated business scope.

6.1 Nexa's identified deficiencies

Specific reference is made to arrangements for affiliate dealings and data access.

All affiliate dealings and system access is subject to stringent controls that are externally audited annually by an auditor with a duty of care to the AER. Annual ring fencing reports and the audit outcomes are reported to the AER. The reports and audit opinion are also made public on the AER's website. Additionally, the value of transactions between the regulated business and its affiliates are reported as part of the regulatory information order (**RIO**) (and previously regulation information notices).

Financial reporting is underpinned by the *Cost Allocation Methodology* (**Methodology**). The Methodology for each distributor has been approved by the AER and forms the basis for the RIO audit.

Branding and cross-promotion are identified as a concern. The Guideline deals extensively with this issue—for example:

- distributors must maintain clear separation between their regulated business and the affiliate
- the Guideline requires the use of branding for regulated services that is distinct and independent from the branding of the affiliate, so that a reasonable person would not infer that the entities are related
- the regulated business is strictly prohibited from advertising or promoting their regulated services with their affiliates services. This includes cross-advertising or cross-promotion
- a regulated business must also not advertise or promote services provided by its affiliate.

Beyond the above, staff separation is required between the regulated business and affiliate:

- staff involved in providing regulated services cannot be involved in the marketing or delivery of contestable services, except in limited circumstances permitted by the Guideline or through a waiver
- the Guideline imposes strict controls on information sharing
- the regulated business must protect confidential electricity information obtained through their regulated activities from their affiliate. Where information is shared with an affiliate, equivalent access must be provided to competitors
- the regulated business must maintain registers and protocols that promote transparency and non-discriminatory access to information.

Each of the above controls are highly prescriptive and effective. Collectively, they impact the potential scale of economies available to distributors and distribution customers. Strengthening of these provisions would only exaggerate the impact on distribution customer bills. We are not aware of any instances where branding and cross promotion has been a material issue for the AER. We therefore question the rationale for imposing further controls at a cost to distribution customers.

Nexa raise concerns with financial ring fencing. They contend distribution customers could be exposed to contestable ventures with higher risk profiles. They argue distributors may do this because regulators will not act for fear of compromising an essential service and a belief distribution customers can absorb losses.

Cross subsidisation is explicitly audited by an external audit with a duty of care to the AER. Further, there are requirements for legal and structural separation, accounting separation and cost allocation, functional separation of people and systems, information access and disclosure controls and finally pricing and transaction controls. We are not aware of the AER being notified, or finding, an instance of cross-subsidisation. Our current EVCI waiver requires explicit public reporting on all EVCI operations under the waiver. Arguably this control goes even further than what is required under the Guideline or RIO.

Nexa raise the absence of transparency around waiver conditions and reporting and complaint and enforcement action by the AER. The current arrangements are described as fragmented and non-standard. There is merit in further transparency around these concerns if it provides greater comfort to stakeholders. Further reform however should not increase the existing burden on distributors but rather focus on the transparency of the AER processes and outcomes.

6.2 Transmission ring fencing arrangements

With respect to transmission ring fencing, we believe the ‘light touch’ approach has compromised market outcomes, ultimately to the detriment of connection applicants and distribution customers.

As noted previously, the transmission connection process is slow, complex and uncertain. It is increasingly difficult to achieve timely and efficient connections to the distribution network and manage network growth. Whilst it’s prudent to undertake due diligence when undertaking transmission projects, the current process is not efficient and leading to major project delays and costs.

We regularly attend meetings with DTSOs with their unregulated affiliate in attendance. We are required to share details of proposed connections with their unregulated affiliate, who is often one and the same person. In some instances, we have found ourselves competing with the same affiliate for terminal station access where capacity is scarce. Land is a scarce commodity and was funded by distribution customers. It is not fair these same customers now need to pay for new transmission capacity because the transmission affiliate has taken that capacity.

Beyond the process, we have grave concerns about the competitiveness of the transmission connection process. DTSOs exercise monopolistic behaviour in most aspects of the connection process. This extends beyond price to contractual terms and conditions.

There has been some limited reform to the *Transmission Ring Fencing Guideline*, but it has been insufficient to generate real change. It remains a document focused on higher level principles with few real operational restrictions. It doesn't require staff separation, prohibition on branding and cross promotion activities or confidentiality arrangements for data.

Energy markets are evolving rapidly. In such circumstances, it's difficult how the justification for a 'lighted handed' approach to transmission ring fencing can be maintained. Transmission connection services are increasingly valuable and scarce. This is nowhere more so than in Victoria where the transmission network is highly constrained. The information asymmetry advantages held by DTSOs are large and have, and continue to, assist their affiliates procure connections, poach customers and lock down access inside terminal stations.

Increasingly distribution and transmission compete for connections. This could extend in the future to other services such as ancillary services, many of which can be provided via the distribution network. We have been building 132kV networks to support requests from our customers. At this voltage, we compete directly with DTSOs. Similarly services such as system security services and frequency support could, and should, be able to be provided by distributors. Lastly, in terms of renewable energy zones, distributors are competing head-to-head with DTSOs.

The weak ring fencing arrangements applying to transmission systematic distorts competition. As generator, load and energy storage markets become more important, the 'playing field' must be equalised so distribution and transmission compete equally.

7. Would Nexa's proposed solution address the identified problem?

We do not believe the Nexa proposals are appropriate. In particular, there is no evidence of the behaviour being alleged by Nexa and we are not aware of any material breaches of the Guideline since its inception by any distributor.

Even if there were a case for more prescriptive action, it is inappropriate to elevate ring fencing provisions into the Rules as proposed on multiple grounds. These include:

- *reduced regulatory flexibility*: the Guideline can be reviewed and amended by the AER relatively quickly through its consultation processes. This contrast with the Rules that require a rule change process taking up to twelve months
- *tailoring of obligations*: the Guideline can easily accommodate differences in jurisdictional arrangements, different types of waivers and flexibility around individual obligations. This is not possible through Rule drafting
- *overprescription*: the Rules are intended to provide high level obligations, not operational detail e.g. staff sharing arrangements
- *compliance/litigation risk*: elevation to the Rules converts non-compliance to a more serious legal penalty, that could result in enforcement action such as financial penalties or litigation. This represents a major escalation in regulatory arrangements.

No evidence has been presented to support the initiatives identified by Nexa (except for transparency and reporting gaps). Systematic failure of the current arrangements has not been demonstrated that would warrant further prescription. The Nexa analysis is principles based ignoring the multiple existing controls already in existence which based on available evidence have been highly successful.

8. What are the costs/benefits of Nexa's proposed solution?

The current costs of complying with ring fencing requirements are material. The external audit costs equate to $120k per annum. Preparation of the annual compliance report, and internal enforcement of the Guideline engages two full time equivalents adding a further $350k per annum. This excludes management time. Dedicated systems and processes have been established to support separation between the regulated businesses and their affiliates. The annualised costs of maintaining these systems is conservatively around $300k. There are also legal costs involved in reviewing and complying with the Guideline that amount to $200k. The total annualised costs is in the range of $970k per annum.

Beyond the direct costs are the opportunity costs. Our affiliates lease separate premises whereas they could have been accommodated in the regulated businesses' existing accommodation. Vehicles and equipment that could have been shared are not. There are also extensive security arrangements in place across the regulated businesses used to ring fence, protect, detect and prohibit entry of our affiliates onto the premises and systems across more than fourteen depots and multiple IT systems. These opportunity costs are difficult to estimate but are large.

While there is not sufficient detail in Nexa's proposed changes to robustly cost the impacts, what is proposed is above and beyond what exists. If accepted, therefore, the rule change would impose substantial costs on market participants.

The benefits however are less tangible, particularly given we are already subject to extensive controls including external audit (as outlined previously).

Lastly, we would like to address the proposed 'market failure test'. The market failure test is intended to increase the difficulty for distributors to offer services in contestable markets. Excluding distributors will impact customer choice and potentially allow other market participants to increase prices or restrict customer choice. The 'market failure test' establishes a high bar for any waiver to be granted, increasing the cost of acquiring a waiver and/or deter distributors from applying for a waiver. This is to the detriment of customers in the new market but also existing distribution customers, who would have benefited through the exercise of economies of scale.

9. Do you agree with ENA that there is a problem with the roll out of EVCI?

We agree there is a “chicken and egg” challenge constraining the development of EV charging infrastructure (**EVCI**). Importantly, distributors are uniquely positioned to deliver charging infrastructure outcomes that are lower cost, faster, larger in scale and with greater geographic coverage than those likely to emerge through market-led investment alone.

9.1 Materiality of the problem

The problem is material because it is contributing to an inequitable distribution of charging infrastructure. Equity concerns were a significant ‘flash-point’ in our engagement program for the development of our recent regulatory proposal, with regional and rural customers in particular—who total over 450,000 in our Powercor network alone—voicing their frustration at how the regulatory framework will leave them behind in the energy transition.

In the context of EVCI, deployment to date has been concentrated on major transport corridors and locations which are already experiencing higher levels of utilisation. This leaves significant customer cohorts underserved, including renters, apartment residents, regional communities and lower-income households. Greater access to charging services across customer cohorts would support broader EV uptake and contribute to government objectives relating to emissions reduction, electrification and fuel security.

9.2 Nature of the problem

The issue is also not confined to charging technologies or sub-markets. All EVCI investment decisions are still likely to favour high-utilisation locations, with underserved customer cohorts continuing to face barriers to access.

A distributor should not be prevented from providing the infrastructure service if it can deliver the desired customer outcomes in terms of cost, speed, scale and geographic coverage. For this reason, the regulatory framework should not pre-emptively exclude charging segments/technologies or geographical locations.

We also do not consider this to be a temporary issue that will be resolved solely through market-led investment. Rather, we support the ENA’s proposed enduring solution, which would allow distributors to seek classification of and provide EVCI services as a regulated service (a direct control service). This approach provides a pathway for coordinated EVCI deployment on existing distributor assets, rather than a fragmented outcome driven solely by the market. Importantly, it would also support the long-term continuity of charging services, including the replacement and renewal of charging assets as they reach the end of their useful lives.

Notwithstanding the above, we support the need for a regulatory process to ensure appropriate controls on a distributor led roll-out. Under the ENA process, this oversight is envisaged as being provided by the AER through its assessment of corresponding revenue proposals.

As a precondition to providing EVCI as a direct control service distributors would be required to submit an EVCI deployment strategy. This strategy would require distributors to consult with stakeholders and transparently set out how deployment locations are identified and prioritised, providing certainty to charging service providers, supporting efficient investment decisions and promoting equitable access to charging infrastructure across different customer cohorts and locations. It would also set out in detail the scale, extent and benefits of a proposed roll-out and demonstrate the need and efficiency for the corresponding costs, The AER would then assess these proposals to ensure they are delivering in the long-term interests of customers.

9.3 Benefits of a distributor led roll-out

Distributors are well placed to deploy EVCI efficiently, which includes rolling out infrastructure at lower cost and at greater speed than a market-led approach. Ultimately, this is what customers want.

For example, distributors can leverage expertise in delivering large-scale infrastructure programs, asset management systems and access to skilled workforces. In Victoria, we have demonstrated this previously, most notably through the efficient roll-out of advanced metering infrastructure.

Our capabilities will reduce deployment cost and complexity for charging infrastructure installed on existing network assets and enable more coordinated rollout programs.

Importantly, competition will still be maintained, with this promoted at the point of supplying the charging service to EV users. Competition at the point of supply will allow providers to offer customers innovative pricing, service offerings and customer experiences that meet the needs of customers.

The benefits of competition at the point of supply are evident today in our limited EVCI trial. As stated earlier in this submission, through our current trial we are promoting downstream competition through roaming eMSPs. Access to our charging network is achieved through an open access platform that multiple competing providers can use to provide electricity supply services to EV users. In the trial, we are seeing energy charges as low as 21 cents/kWh under a model where multiple eMSPs compete at the point of supply, compared to 50 cents/kWh at some market-led sites where no competition is occurring.

Through the use of open access platforms we expect the market to evolve in a way that promotes competition and innovation at the customer interface.

10. Would the ENA's proposed solution address the identified problem?

The ENA's proposed solution addresses the key barriers to the efficient and equitable deployment of EVCI by enabling distributors to provide EVCI on existing network assets as a regulated service, while preserving competition in the provision of charging services to end users. Competition at the supply point would continue to drive innovation, customer choice and service quality.

The proposed rule change recognises that the infrastructure component of EV charging, and the customer-facing charging service are distinct parts of the value chain. By allowing distributors to provide and maintain the underlying infrastructure while retailers and charging operators compete to supply charging services, ENA's proposal addresses current gaps in infrastructure deployment without displacing competition where it delivers the greatest customer benefit.

The proposed rule change also contains appropriate guardrails to ensure distributors deliver efficient outcomes in the long-term interests of customers. These include the requirement for distributors to develop and consult on an EVCI deployment strategy, AER assessment and approval of service classification, and the application of ongoing economic regulation. It is therefore not necessary to apply further regulatory limitations, as this would create additional costs and potentially delay the rollout of EVCI.

Finally, the proposed within period re-opener specific to EVCI addresses a practical implementation issue. Without this mechanism, some distributors may need to wait until their next regulatory cycle (up to 5 years) to seek service classification and propose expenditure, unnecessarily delaying infrastructure deployment and the benefits associated with increased EV adoption.

Overall, the proposal combines the efficiencies associated with large-scale infrastructure deployment with the benefits of competitive service delivery. This model is well placed to support efficient investment, equitable access and the timely deployment of charging infrastructure on existing network assets, while continuing to promote innovation and customer choice in EV charging services.

11. What are the costs and benefits of ENA's proposed solution?

1. What do you consider the direct and indirect costs and benefits over the short and longer term would be of the ENA's proposal to amend the NER to enable DNSPs to roll out EVCI and to provide EV charging service providers open access to EVCI services?

2. Do you think these costs and benefits would differ depending on whether the AER classifies the service as a standard control service or an alternative control service? Are there any other interdependencies (e.g. with government policies) that we should take into account?

Allowing distributors to roll out EVCI with open access competition for EV charging services will best meet customer outcomes both in the short and longer term.

In the short term, allowing distributors to roll out EVCI will address the chicken and egg problem, giving customers the confidence to switch to electric vehicles and contribute to a greater reduction in greenhouse gas emissions.

In the longer term this model will continue to provide customers with the lowest cost access to public EV charging. At the charging infrastructure level, distributors can leverage their workforce expertise to maintain and replace EV charging infrastructure, delivering benefits to customers through economies of scale. The proposed model will also ensure that public EVCI can continued to be provided in lower-demand areas, ensuring continuity of access for regional customers.

Classification between alternative control service (**ACS**) and standard control service (**SCS**) will materially impact who is able to receive the benefits of public EVCI. By classifying the service as SCS, the costs and the benefits of public EVCI will be spread across each distribution network's customer base. This will ensure EVCI can be equitably rolled out across a distribution network. It will also provide certainty to distributors that they will be able to recover their efficient costs in the rollout of public EV charging infrastructure.

If the AER were to classify the service as ACS, then distributors will need to limit the deployment of EVCI to locations where there is a third-party request to provide EV charging services. This is because under the ACS classification, distributors cannot recover costs from the broader customer base and must instead recover the costs from parties using or requesting the service.

Under an ACS classification, distributors are therefore exposed to a higher investment risk, limiting the ability of distributors to roll out infrastructure in lower-demand or regional locations where utilisation may be lower, but charging infrastructure is no less important. As noted previously, our experience through our reset regulatory determination process was that customers strongly supported equitable outcomes (e.g. urban customers supported regional and rural electrification programs and resilience investments even where they did not expect to benefit directly themselves, recognising the importance of equity and access for essential services and the benefits of all customers being able to participate in the energy transition).

We therefore consider an ACS classification would have the potential to further widen the gap between customer cohorts, including their ability to participate and benefit from the energy transition.

12. Prioritisation framework for the Review

We broadly support the assessment criteria proposed by the AEMC for this review.

However, while the AEMC has set out its intended criteria, it has not proposed how it may weigh the various criterion. We consider the first criterion, outcomes for consumers, should be the key focus of this review, with criterion two to five predominately outlining potential pathways in which to achieve the first criterion.

Further, many arguments made around ring-fencing and service classification to date have relied on hypothetical consumer harm, rather than evidence. We would encourage the AEMC to always link its considerations back to actual customer outcomes.

We would also encourage the AEMC to include equity in its consideration of consumer outcomes. Ensuring all consumers can participate and therefore benefit from the energy transition is important to maintain trust in the transition and has been a significant and recurring theme across our stakeholder engagement programs.

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