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11 April 2024

Ms Lisa Shrimpton
Director
Australian Energy Markets Commission (AEMC)
Level 15/60 Castlereagh St,
Sydney NSW 2000

Dear Ms Shrimpton,

Draft rule determination - Unlocking CER benefits through flexible trading

Endeavour Energy appreciates the opportunity to provide feedback to the AEMC's *Unlocking CER benefits through flexible trading* draft rule. The draft rule will provide customers the option to establish secondary National Metering Identifiers (NMIs) for their CER devices and allow:

- small customers to have their flexible CER identified and managed separately from their passive load, and services provided from these devices to be settled on-market;
- large customers to access services from multiple financially responsible market providers (FRMPs) without needing to establish a second connection or use the embedded network framework; and
- energy flows to be measured and settled using in-built metering technology.

While we support improving customer access to new and innovative products and services that allows them to optimise the value of their CER investment in a way that benefits all customers, and acknowledge the AEMC undertaking detailed cost-benefit analysis to consider the merits of proposed rule changes and reforms, we do not consider that establishing secondary NMIs will unlock substantially greater benefits for customers that cannot more cost-effectively be delivered through existing arrangements. Specifically, we are concerned that:

- Energeia's analysis derives a net benefit that is marginal and achievable only in certain scenarios. Furthermore, the analysis overstates avoided metering cost benefits by assuming network demand management services would otherwise require the installation of an additional meter; and
- the efficient signalling of network charges and dynamic operating envelopes to large customer CER will be dependent on, and vulnerable to, the contractual arrangements between FRMPs.

These two issues are discussed in more detail in Appendix A. If you have any queries or wish to discussion our submission further, contact Emma Ringland, Head of Regulation and Investments at Endeavour Energy via email at emma.ringland@endeavourenergy.com.au.

Yours sincerely

Colin Crisafulli
General Manager Future Grid and Asset Management

Appendix A: Detailed response

Observations regarding cost-benefit analysis

> We consider Energeia's cost-benefit analysis does not provide compelling support for the draft rule and believe there are opportunities to make the analysis more robust.
>
> We **recommend** the AEMC:
>
> - Revise the assumption that additional smart meters are required for CER to provide network services to account for the shift towards demand management programs and initiatives that leverage the in-built functionality of existing smart meters or device.
> - Revisit the assumption that NMI allocation and connection offer costs are smeared to reflect the standard practice.
> - Test the sensitivity of the analysis with respect to these assumptions and reassess whether the net benefits are sufficiently significant across all modelled scenarios and CER types - in particular EVs - to support the proposed framework.

Despite many stakeholders expressing divergent views and uncertainty behind the rationale for introducing AEMO's proposed flexible trading model throughout this consultation, the draft rule is broadly consistent with the changes the AEMC suggested it would make in their Directions Paper.

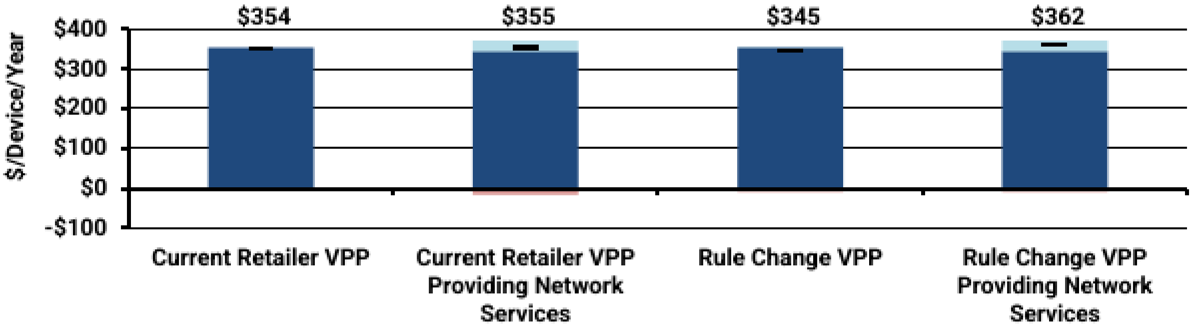
This suggests the AEMC's position has been closely informed by the cost-benefit analysis conducted by Energeia, which suggests the draft rule could unlock additional benefits for consumers with relatively low implementation costs. Energeia also estimated that approximately 157,000 CER devices on average would need to take up trading via a secondary NMI each year for the draft rule to produce net benefits.

We support the AEMC undertaking detailed cost benefit analysis to establish the merits of significant rule changes and reforms. However, we have reservations the quantified net benefits are neither sufficiently material nor the assumptions underpinning them appropriately robust to warrant making the rule change, as set out below.

Quantified net benefits

For instance, the analysis estimated the incremental benefit to small customers trading their batteries would be approximately $7 or 1.97% per year, reflecting the difference between the avoided metering installation costs and pro-rata share of system implementation costs.

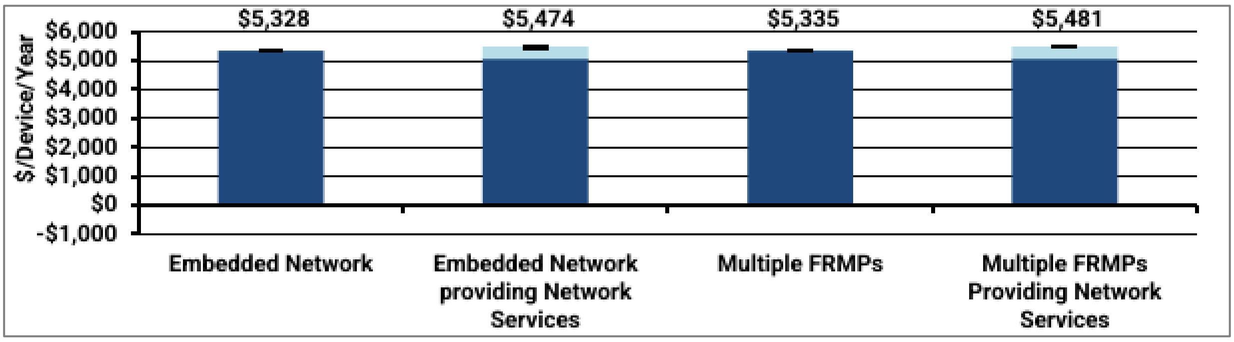
Figure 1: Small Customer Battery Case Study Draft Results



Source: Energeia

For large customers, the incremental benefit is also $7 but represents a mere 0.13% net benefit improvement. We consider this is too marginal to justify customers bearing implementation costs associated with establishing a framework which from the outset is at risk of being underutilised through it being voluntary and not having consensus support from key stakeholder groups.

Figure 2: Large Customer Battery Case Study Draft Results



Source: Energeia

We also note Energeia has made the following comments in relation to the value of the draft rule under the small customer Electric Vehicle (EV) scenario:[1]

> *However, the contrast between the results for small customer battery and EV charging loads, is that the benefits of providing network services using an EV charger, with or without the rule change, do not outweigh the costs of either NMI allocation or installing a new meter…. The per device benefits of network demand management and tuning do not outweigh the costs of establishing this framework. These benefits are also being provided by smart metering, and the rule change would only accelerate the timing of their realisation where CER is deployed ahead of the full smart meter deployment planned by 2030.*
>
> *Hence, this provides evidence that the rule change is not economical for EV chargers, and other small customer unidirectional loads.*

Although EVs currently represent a small proportion of total connected CER, we are forecasting EV penetration to reach over 90% in 2040, significantly exceeding solar PV and battery penetration rates of 52% and 30% respectively. Similar strong growth is expected across the NEM and has contributed the development of EV specific retail offerings and prices which we consider are likely to evolve and be the main trigger for customers looking to use the new framework to separate their EV from their inflexible load. We also expect managing EV charging and discharging within network capacity constraints to be a core objective supporting the development of flexible network connection models.

Therefore, we encourage the AEMC provide clarification in the final rule on how it expects the new arrangements will deliver net benefits for this key CER technology.

Demand management participation

The analysis indicates a positive net benefit is only achieved for small customers if their batteries are used to provide network demand management (DM) services. Also, the value of avoided metering costs which is the key driver of benefits, assumes that an additional standard smart meter is currently required for DM participation.

These assumptions may not be representative of the current or future DM arrangements and therefore may overstate the metering cost savings purported to be delivered by the draft rule.

In our view, participation in network-developed DM programs is unlikely to be among the key considerations for customers when making decisions on buying and using their battery and therefore it should not be assumed that they would willingly provide network services from them.

Rather, the value proposition would likely be informed by savings and/or reliability improvements achieved through self-consumption and rewards available for activating their battery either under their own control or by outsourcing control through product offerings from their existing or a

[1] Energeia, Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Draft Cost-Benefit Analysis, 29 February 2024, p.31

competitor retailer. Customers can currently attain these wholesale and other market-based rewards through Virtual Power Plants (VPP) and other aggregator schemes with participation not contingent on having a second NMI or additional smart meter installed. As Energeia's analysis indicates, the rule change results in a net cost for participation in VPP programs.

With regards to network DM, programs are typically tailored to address demand constraints in specific locations and often target loads such as air-conditioners and pool pumps. Rewards for participation are not generally available to all CER customers and are provided through off-market mechanisms (e.g., CER rebates, bill credits or direct financial payment).

The emergence of demand based and time-of-use tariffs is now helping to incentivise behaviours to deliver the changes in energy use which previously could only be achieved through DM. That is, pricing reforms coupled with smart metering is helping networks to transition from bespoke DM programs which provide a limited number of registered participants with off-market rewards (e.g., CER rebates, bill credits or direct financial payment) to scalable models that provide more customers the opportunity to benefit through market-based rewards when responding to dynamic signals.

Technology improvements will likely increase opportunities for customer participation in conventional DM programs, however a significant uplift is required to match the levels assumed in the analysis which may not be realistically achievable in the short to medium term. This is exacerbated by the size, cost and dependability issues which are often barriers preventing DM from displacing network capital investment, which Energeia has recognised may require a separate rule change to remove in order to unlock the full value of the draft rule.

Metering cost assumptions

Where DM projects have the potential to be scaled, their costs can be reduced by making use of smart metering functions or communicating directly to CER devices using Demand Response Enabling Device (DRED) capabilities, thereby avoiding the additional metering costs assumed in the analysis. As is the case for VPPs, deploying DM programs more widely across the network is not contingent on customers establishing a secondary NMI or installing an additional smart meter.

An example of this is our Off Peak Plus project which utilises smart meter functionalities to deliver an improved and consistent hot water service to off peak customers. This is facilitated through a "solar soaking" function which has improved our ability to host more rooftop solar in constrained areas.

As smart metering penetration increases, aided by the AEMC's *Accelerating smart meter deployment* rule change, programs like this could be scaled more broadly as a low marginal cost approach to improve CER hosting capacity and could be extended to provide cost effective access to EV charging. Irrespective of the many possible applications and the rate at which the program evolves to become a BAU network service, the benefits can be attained by utilising all the capabilities of a single smart meter and therefore should be reflected in Energeia's analysis.

NMI establishment costs

The analysis also assumes that retailers would smear NMI allocation and connection offer costs across all retail customers. We understand it is normal practice for retailers to charge the requesting customer these fees in full, consistent with other ANS service provided by the DNSP (e.g., special meter reads, disconnections and reconnections). The effect of this upfront cost barrier on additional NMI take-up rates should be factored into Energeia's findings.

It is imperative that analysis relied on by the AEMC is transparent, balanced and robust particularly where it supports a regulatory change that is does not have consensus support or, as in the case with this consultation, is somewhat inconsistent with stakeholder feedback. Therefore, we encourage the AEMC to test the sensitivity of the results to make the analysis more robust so that customers can be confident that the implementation costs they will incur will deliver offsetting benefits and are justified.

Observations regarding network signals

> We are concerned the flow of cost-reflective network tariffs and dynamic operating envelope compliance could be hindered as the flexible trading model relies on contractual agreements between FRMPs and their shared customers.
>
> We **recommend** the AEMC:
>
> - Consider regulatory measures which prevent secondary FRMPs from shielding price-responsive CER from cost reflective network charges.
> - Consider providing customers with additional safeguards to ensure their FRMPs are operating their CER within DOEs to achieve better compliance outcomes.
> - Confirm the wiring and switching arrangements do not breach jurisdictional Service Installation Rules.
> - Ensure the provision of secondary settlement point metering data (including power quality data) to DNSPs is consistent with reforms made through the *Accelerating smart meter deployment* rule change.

From a network perspective, flexible trading with multiple FRMPs at a single connection introduces a variety of safety, pricing and operational issues. These have been discussed at length throughout this consultation with concerns primarily related to complications in splitting network charges between NMIs and uncertainties over whether variable pricing and dynamic operating envelope (DOE) signals will be able to flow through to the portion of the customer's load that is able to efficiently respond to them.

Network charges

For large customers opting into this framework, the draft rule specifies that the primary FRMP is responsible for paying network charges. The AEMC has also clarified that any arrangements through which any portion of these charges including any CER-specific tariffs are passed through to secondary FRMP would be negotiated between the respective FRMPs.

This clarification provides us with certainty over use-of-system revenue collection responsibilities. However, we have concerns about the frameworks reliance on competing entities entering into contractual agreements on a voluntary basis, noting the draft rule does not require a contractual relationship between primary and secondary FRMPs.

Whilst we are not best placed to provide insights on the commercial motivations of retailers, it would be reasonable to expect the primary FRMP (controlling the inflexible load) to de-risk its exposure to the cost-reflective network charge by requiring secondary FRMPs (controlling the flexible CER) to pay a portion of the charge. Depending on the level of competitive tension between FRMPs, the following scenario could arise:

- in the absence of any requirement to do so, secondary FRMPs may not agree to contribute to a network charge, potentially allowing them to market the avoidance of network charges as a benefit to its customers;
- the primary FRMP would have little countervailing negotiating power as the customer has exclusive right over the establishment of a secondary NMI and appointment of any FRMP to the NMI;
- in the absence of any agreement, the primary FRMP may not be able to pass through any network tariffs to the secondary NMI.

Hindering the flow of network price signals to the price-responsive portion of a customer's connection will lead to inefficient utilisation of the network and higher costs over time and may deter retailers from making competitive offers to customers who have established a second NMI or are considering so.

In our view, the effectiveness of dynamic tariffs being contingent on the agreements stuck between FRMPs is a significant shortcoming of the flexible trading model. Should the AEMC progress flexible trading in the final rule, we consider it should also introduce appropriate safeguards which avoid the possibility of perverse pricing outcomes that subvert the intention and effectiveness of cost-reflective network pricing.

Dynamic Operating Envelopes

DOEs are integral to the efficient integration of CER and our transition to a Distribution System Operator (DSO) model and we plan to progressively implement DOEs through flexible connections agreements with customers.

However, flexible trading inherently creates problems for flexible connection arrangements because no single party can control the aggregate of all load and generation – passive and flexible – to ensure that the site, as a whole, conforms to a DOE. Unchecked, it risks competitive entities prioritising their own interests at the expense of the customer which could damage trust and confidence in the market.

To address this concern, the AEMC has stated that DOE's will continue to be issued at the connection point level (i.e., to the primary FRMP) with compliance managed through contracts between the customer and the network, potentially supported by contracts between the customer and its FRMPs.

Where customers are made accountable for DOE compliance, we consider it imperative that contracts contemplate scenarios where multiple FRMPs are involved and specifies arrangements to ensure DOE breaches are avoided and the rectification processes to be followed when they are. It should also be acknowledged that it is possible that some large customers may be deterred from entering multi-FRMP arrangements though this model where:

- they perceive it introduces a higher risk of non-compliance; or
- the complexities of establishing and monitoring compliance responsibilities do not align with their preference for simplicity in their energy arrangements and contracts.

It is important that DOE compliance arrangements are not vulnerable to the same issues which have resulted in low compliance to CER technical standards. We encourage the AEMC to consider whether additional regulatory safeguards are needed in contracts between customers and FRMPs to ensure customers have adequate avenues of recourse should a FRMP not fulfil its contractual obligations. This certainty is also valued from a system operation perspective as a breach would not only make the customer liable for any losses for non-compliance, but the DNSP would also lose the ability to apply back-stop controls as needed to ensure the network operates within safe technical limits.

Service Installation Rules

The NSW DNSPs submission to the Directions Paper highlighted the need to ensure the proposed metering and wiring arrangements contemplated in the rule change request are consistent with requirements set out in jurisdictional Service installation Rules (SIR). Specifically, we expressed concerns related to safety risks associated with switching loads between NMIs and the possible non-compliance with the NSW SIR.

The AEMC has noted that some jurisdictions impose restrictions on switching between connection points and considered that:

- customers and FRMPs will take these rules into account when choosing arrangements that best suit their business model; and
- the choice to switch and any risks posed by customer switching could be managed by contractual arrangements between the customer and FRMPs.

This response is ambiguous and gives the impression that SIR requirements can be subverted when the customer and FRMP agree on ways to manage wholesale market settlement risks from load shifting between points. We remain concerned that any such negotiated arrangements may not sufficiently mitigate network safety and operational risks associated with switching loads between NMIs.

The prospects of the framework being adopted would be improved by providing all affected parties assurance it does not create compliance issues in participating jurisdictions. We consider that it would be prudent for the AEMC to confirm with each jurisdictional regulator ahead of the final rule that switching arrangements conform to the respective SIR. This would allow the regulator sufficient time to make any required administrative amendments to the SIR where any misalignment is identified.

Network visibility

Under the draft rule, DNSPs will be responsible for establishing secondary NMIs and maintaining the standing data at secondary settlement points. Although this will require us to undertake some system enhancements, we agree DNSPs are best placed to provide this service at the lowest incremental cost to consumers.

The draft rule also enables DNSPs to access secondary NMI metering data. We consider this a necessary extension of the existing data access rules that will enable DNSPs to continue to have visibility of energy flows irrespective of the number of metering installations or NMIs linked to a single connection.

It would also be appropriate for arrangements being progressed through the AEMC's *Accelerating smart meter deployment* rule change - which enables DNSPs to access basic or additional power quality data (PQD) from a smart meter at the primary NMI - to also apply for metering installed at the secondary NMI. It would also be important that any type of new metering introduced by the rule and used at a secondary settlement point be able to provide the same PQ data in the requisite format and timeframe as required of meters at the primary settlement point.