Ms Rachel Armstrong
Policy Advisor
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

1 February 2017

Dear Ms Armstrong

Electricity Network Economic Regulatory Framework Review

CitiPower and Powercor welcome the opportunity to respond to the Australian Energy Market Commission's (**AEMC**) Electricity Network Economic Regulatory Framework Review Approach Paper (**Approach Paper**).

In this submission we have highlighted several aspects of the regulatory framework where reform could better assist distributors to adapt to market changes. In particular, we consider:

- a more proactive transition to cost reflective pricing will help ensure consumers use the network efficiently;
- metering contestability arrangements should not undermine distributors' ability to engage in load control activities;
- the industry should debate the merits of cost reflective network availability and network exit fees;
- efficient investment in the network and consumer side investment will be promoted by transparency in the composition of retail charges;
- the National Electricity Rules (**NER**) and government policies are hindering efficient deployment of Distributed Energy Resources (**DER**);
- the industry should consider the merits of network cost models (such as the Transform Model used in the United Kingdom) as a tool to plan the network and ensure expenditure is efficient;
- encouraging more research and development (**R&D**) may lower the cost of readying the network for DER and other market changes; and
- we already actively seek to use DER in place of traditional network solutions, but in most cases DER is not yet the efficient choice. Incentives may be required to kick-start DER.

If you have any queries on this submission, please contact me on (03) 9683 4465 or bcleeve@powercor.com.au.

Regards

Brent Cleeve
Head of Regulation

Framework Review

1.1 Introduction

There have been significant changes to the electricity market over the past 10 years and we expect this to continue. For example, consumers have more and higher consuming electrical devices which they expect to use at all times of the day. More recently, environmental considerations combined with declining DER technology costs are resulting in decentralised supply—changing the way consumers engage with the electricity market. This is also leading to a myriad of new environmental policies that are affecting electricity prices and in turn, electricity use patterns.

The AEMC has asked 'does the economic regulatory framework allow and incentivise networks to adapt to the extent necessary to changes in the market, including decentralised supply'.[1] The AEMC has proposed three key themes for its review:

- continued implementation of network pricing reform;
- the ability of networks to utilise increasingly diverse grid supply and network support options; and
- different network operating models.

Pricing policy is a key area that can assist or exacerbate the challenges distributors face in adapting to market changes depending on whether the policy incentivises efficient use of the network. The pricing policy considered as part of this review should be broader than tariff policy, particularly given the increasing penetration of DER. In this submission we have highlighted a number of reforms to existing regulations, and potentially new regulations, that would allow distributors to better respond to current and expected changes in the electricity market.

There are strong incentives for distributors to use diverse grid supply options to manage the network. This has led to investigations into the use of DER in place of traditional solutions. Nevertheless, DER is generally not yet commercial as a network solution, and encouraging further uptake of DER would require policy makers to increase the current or add new incentives.

Our response to the third theme of network operating models was submitted to the AEMC on 19 January 2017.

Most issues raised in our submission could be addressed within the NER, although we have also included broader policy considerations for the industry and COAG Energy Council to consider.

1.2 Pricing reform—load customers

Pricing policy for load consumers is not promoting efficient outcomes in all cases. We outline our considerations of this below.

1.2.1 Victorian tariffs

The 2014 tariff reforms provide sufficient flexibility and guidance to set tariffs that promote the efficient use of the network for load customers. In response to these reforms we developed

[1] AEMC, APPROACH PAPER; Electricity Network Economic Regulatory Framework Review, 1 December 2016, p. 6.

residential demand tariffs and we continue to offer Time of Use (**ToU**) tariffs. This is the first step towards efficient pricing.

The Victorian Government has adopted an opt-in approach to cost reflective network tariffs.[2] In our experience, opt-in tariffs have a low take-up because consumers generally stay with the default option. For example, we have offered residential ToU tariffs on an opt-in basis from 2013 and the current take-up is only 0.3% and 0.4% for CitiPower and Powercor respectively, even though a higher proportion of consumers would likely lower their bills if they took up the tariff. Experiencing low take-up of opt in tariffs is not unique to us.[3]

In our 2017-2020 Tariff Structure Statement, we designed demand tariffs to alleviate network constraints and augmentation. Currently, 10 per cent of our network is used on less than two days per year. The tariff balances consumers' desire to face demand charges during a narrow window enabling them to better respond to the incentive, with the higher pricing impact from selecting a very narrow window. Additionally, we recognised consumers are not familiar with demand charges and so we proposed a 'soft start' whereby:

- demand charges would be introduced gradually over a four year period (starting at 20 per cent of its final value), with a corresponding reduction in our usage charge component;
- existing residential customers would have the option to opt-out and revert to a non-demand network tariff in the first 12 months.

Given our experience with ToU tariffs, we are expecting the take-up of these opt-in demand tariffs to be similarly low. We believe, however, that the market is ready for demand charges as a result of:

- distributors' proposed soft start to demand tariffs based on extensive consumer consultation;
- state wide alignment of distribution demand charge design, assisting consumers to understand their operation;
- in home displays showing live electricity usage data and apps showing daily use, providing consumers with knowledge to manage their electricity demand; and
- high awareness of electricity prices and a desire for consumers to take control of their electricity bills.

We would therefore support a more proactive 'opt-out' transition to cost reflective charging in order to lower overall network costs.

Location charging

Tariffs will never be truly cost-reflective unless there is a transition to locational based charging. This will:

- reduce demand in areas with network constraints and encourage better utilisation where capacity exists;
- reduce subsidies between consumers; and
- prevent micro-grids from cherry picking the most profitable areas in which to operate, which could lead to higher prices for consumers left connected to the network.

At this time, we consider consumers are unlikely to be ready to accept locational tariffs in the transition towards more cost reflective pricing. Therefore, non-tariff based mechanisms will be required in the medium term to provide incentives for more efficient customer behaviour.

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2 DELWP <http://www.delwp.vic.gov.au/energy/electricity/managing-electricity-demand>

3 The Brattle Group, Architecting the Future of Dynamic Pricing Dynamic Retail Pricing for More Efficient Outcomes; ACCC/AER Regulatory Conference 2014 Brisbane, Queensland; Ahmad Faruqui, 8 August 2 0 1 4, slide 31, 32

1.2.2 Load control

We are exploring ways to reduce load and defer augmentation. We have already utilised network support payments to secure embedded generation in certain locations to defer investment. We are now exploring how we can secure cost-effective load reduction in certain locations. While load growth has slowed recently, targeted load reduction can still lower augmentation costs (and this will again become more important during the next phase of load growth).

Load control activities are potentially facing barriers from metering contestability reforms. If the national metering functional specification is adopted in Victoria, Advanced Metering Infrastructure (**AMI**) may not have load control capability. Even if the higher Victorian meter functional specification is adopted, it is not certain whether:

- agreement can be reached with metering coordinators to provide load control services; and
- distributors will have access to live power flow information in order to target load control activities to periods when they are needed.

1.2.3 Availability and Exit fees

DER costs are rapidly falling, providing consumers with alternative sources of electricity. It is conceivable that this will lead some consumers to seek network back-up and rely primarily on their DER or seek full network disconnection and rely solely on their DER.

Distribution networks are designed to provide at least sufficient capacity to supply existing consumers. Consumer can currently:

- only use the network from time to time as back-up; or
- seek a remote disconnection from the network at very little cost and no ongoing charges, but at any time seek to remotely re-connect at very little cost; or
- completely disconnect from the network without paying an exit fee or any ongoing charges.

In an environment of static or declining demand, all remaining consumers would bear the cost of stranded capacity. Network availability and network exit fees would assist in ensuring that consumers in the above circumstances face the network costs they have created.

Exit fees have been applied to other aspects of the electricity framework including:

- public lighting—in Victoria, distributors are required to charge a written down value for public lights that are replaced before the end of their useful life. Ergon Energy charge a one-off exit fee, which is payable when a public light is scrapped before the end of its useful operational life;
- metering—exit fees apply from the start of meter contestability until 2020 for Victorian AMI that are replaced before the end of their useful life. In other jurisdictions, the AER has rules that customers pay an ongoing fixed charge for meters installed by the network regardless of whether they opt for a contestable meter; and
- Ofgem is considering an annual insurance premium similar to an exit fee for access to the UK electricity grid.[4]

There does not appear to be an explicit framework barrier to charging exit fees, although it is neither explicitly allowed. Before such fees are implemented, we believe the merits should be debated by the industry and policy makers.

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[4] Telegraph <http://www.telegraph.co.uk/news/2016/05/29/households-could-be-charged-annual-insurance-premium-for-access/>

1.2.4 Promoting efficient investment

The AEMC has asked whether the framework is providing incentives for participants to make the most efficient investment decisions.[5] We consider the interaction between environmental policies and the regulatory framework is not leading to efficient investment.

The costs from non-network related schemes are being recovered through the regulatory framework and included in electricity (and distribution) prices. These typically relate to environmental policy such as feed-in-tariffs and the proposed Renewable Energy Auction Scheme—targeted at increasing renewable generation and creating jobs—the costs for which are proposed to be recovered through distribution tariffs.[6] This has the potential to distort consumer-side investment and may lead to network under-utilisation.

The regulatory framework is limited in its ability to restrict charges to only those associated with the delivery of electricity. The regulatory framework could however require the charges that make up consumers' electricity bills to be separately identified, for example by wholesale, network, retail and government scheme charges. This price transparency would promote more efficient investment by:

- improving market analysis and intra-state price comparisons—a clear understanding of each market segments' contribution to consumers' bills will help to focus debate and policy at the right market segment. For example, it may provide clarity on the level of retail competition and businesses' efficiency;
- promote efficient retail competition (rather than switching based on a partial understanding of tariff rates[7]) through simpler comparisons of margins. In turn this may reduce consumers' electricity bills and promote more efficient consumer side investment; and
- promote a better understanding different 'green scheme' costs and in turn may foster support for efficient schemes.

Price transparency could enable consumers to make informed choices on how they procure and use electricity, and will promote more efficient investment.

1.3 Pricing reform - efficient deployment of Distributed Energy Resources

Of equal importance to load customer pricing are the pricing policies underpinning DER deployment. Costs associated with integrating DER into the distribution network have increased, particularly in networks like Powercor's that are conducive to DER growth.

It is important for the regulatory framework to minimise costs and maximise the benefits from DER given its current and expected prevalence. When installing DER, consumers do not face the costs they impose on the network.

More detailed discussion on cost drivers and benefits from DER was outlined in our submission to the Distribution Market Model consultation. In this submission we explore current barriers to the efficient DER deployment.

5 AEMC, APPROACH PAPER; Electricity Network Economic Regulatory Framework Review, 1 December 2016, p. 11.

6 DELWP, Victorian Renewable Energy Auction Scheme; Summary report of stakeholder submissions <http://www.delwp.vic.gov.au/__data/assets/pdf_file/0003/364008/DELWP_2016_Victorian-Renewable-Energy-Auction-Scheme_Summary-report-of-stakeholder-submissions_final.pdf p. 13.

7 We believe that some consumers switch retailers based on the advertised discount, rather than based on a comparison of the margins and tariff rates that affect their electricity bill.

1.3.1 Installing micro embedded generation (e.g. solar PV)

Under chapter 5A of the NER, and the Australian Energy Regulator's (**AER**) connection charge guideline, distributors are unable to charge micro embedded generators an augmentation charge for the cost imposed by their connection to the network.[8]

We accept a policy whereby micro-embedded generators do not pay for augmentation (this is consistent with the policy for residential load consumers below the AER's augmentation charge threshold). If this position is continued however it is necessary to make clear that augmentation for removing technical constraints to allow micro embedded generation connection is a standard control service. Otherwise, distributors may be forced to restrict export capable connections when the penetration exceeds certain technical thresholds on the network. This would be a matter for the AER to clarify.

An alternative approach is to change the framework by allowing distributors to charge an average augmentation rate to micro embedded generators. This charging arrangement is used for consumers above the AER's shared network augmentation charge threshold.[9]

Charging augmentation rates to micro embedded generators but not residential consumers may not be inconsistent policy. It would recognise consumers with exporting solar PV are typically more engaged with the electricity market and could make more informed choices than other residential consumers. Further many micro embedded generators are developed by property developers to meet energy efficiency standards, for whom an augmentation charge is likely to be immaterial.

1.3.2 Network cost models

The costs to integrate DER will increase as its use becomes more prevalent, as discussed in our submission to the Distribution Market Model consultation. We believe that tools to help ensure DER is integrated efficiently should be considered for use.

In the United Kingdom (**UK**), distributors and Ofgem partnered with EA Technologies to develop the Transform Model. The model examines the impact of new technologies and customer behaviours on network demands. It quantifies how network loads will change in the face of disruptions and the ways in which the network demands can be best met via a combination of traditional and innovative approaches. Although highly aggregated, it did enhance understanding across the sector of the impact of DER.

A tool similar to the Transform Model could assist the industry to accommodate DER efficiently. We believe such models should be considered and assessed for suitability in Australia by market participants. We are already closely considering adopting such models to aid in future network planning, tariff and expenditure decision making.

1.3.3 Research and development

Engaging in more speculative research projects can enhance dynamic efficiency and lower overall costs to consumers. The regulatory framework does not incentivise distributors to undertake R&D, trials and demonstration projects that yield uncertain commercial returns. This is particularly true where benefits occur in future regulatory periods, do not directly accrue to the distributor or are linked to the role of energy networks in the transition to a low carbon economy. A significant factor is the low allowed rates of return—6.11% nominal vanilla (or 3.70% real rate of return) for our business in 2016.[10]

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8 NER Chapter 5A, 5A.E.1(b)(1) and 5A.A.1

9 AER, connection charge guidelines for electricity retail customers: Under chapter 5A of the National Electricity Rules Version 1.0, June 2012

10 The final rate of return applied will depend on the outcome of the Australian Competition Tribunal's appeal decision.

In the UK, Ofgem introduced a network innovation competition (**NIC**) where electricity network businesses compete for funding for the development and demonstration of new technologies, operating and commercial arrangements. The NIC encourages innovation in the way these businesses design, develop and operate their networks. Funding is provided for the best innovation projects which help all network businesses understand how to deliver environmental benefits, cost reductions and security of supply as the UK moves to a low carbon economy.

In December 2016 the AER began its review of the Demand Management Incentive Scheme (**DMIS**). Similar to the NIC, the review considers developing a bidding mechanism where project funding is awarded via competitive tender to encourage distributors to deliver ground-breaking R&D projects.[11] These projects however are limited to demand management projects as required by the NER, and may not aid integration and deployment of DER.

We propose that a competitive funding scheme for R&D (with a broader mandate than demand management) be considered in the NER.

1.4 Distributors' use of diverse supply and support

The Approach Paper asks whether the regulatory framework is providing the right incentives for distributors to choose the most economically efficient option to address network constraints while maintaining security and reliability.[12] Broadly, the options are traditional network augmentation or DER.

There are a myriad of incentives placed on distributors to ensure the economically efficient option is selected including:

- operating an efficient network to increase business value and shareholder returns;
- our business driver to keep network prices low and afford consumers choice and flexibility in how they use DER. If network prices are prohibitive or the network becomes a barrier rather than a facilitator of consumers' DER preferences, consumers will seek to bypass the network over the long term. This is a strong incentive for choosing efficient options and responding to consumer preferences;
- the AER's revenue cap, Capital Expenditure Sharing Scheme, Efficiency Benefit Sharing Scheme and use of benchmarking to assess expenditure place incentives on distributors to choose the most efficient method to deliver network services;
    - we are also seeking stronger incentives for distributors that benchmark well to seek out more difficult to achieve efficiencies. We have therefore discussed with the AER higher sharing ratios under these incentives;
    - these efficiency incentives are balanced adequately with reliability and safety considerations through the Service Target Performance Incentive Scheme (**STPIS**), F-Factor and technical operating requirements.

We actively seek opportunities to use DER in place of traditional augmentation. In the summer of 2013–2014, we used Royal Melbourne Hospital's existing embedded generation for network support in the CitiPower network, to respond to a number of peak demand constraints within the Melbourne City Business District. We also relied on the hospital's network support over the summers of 2011–2012 and 2012–2013 on an informal uncontracted basis, to address higher than expected load at risk as a result of either peak demand growth or delays in network augmentation. In this case, the distributed generation provided value and the generator was compensated through network support payments in those periods. However, the total capacity of

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11 AER, Consultation paper; Demand management incentive scheme and innovation allowance mechanism, January 2017, p. 51.

12 AEMC, APPROACH PAPER; Electricity Network Economic Regulatory Framework Review, 1 December 2016.

distributed generation in that location was not sufficient to completely remove the need to augment the network.

Our consideration of these issues is discussed more fully in response to the AEMC's Contestability of Energy Services Consultation Paper which considers whether distributors should be allowed to own or install DER devices.

1.4.1 Efficient barriers to DER

It is important to distinguish between efficient and inefficient barriers to DER. The preceding discussion demonstrated that distributors are incentivised to procure efficient DER, but DER is still at a disadvantage to traditional solutions.

For a number of large projects, including Truganina, Geelong East and Melton/Bacchus Marsh network constraints, we consulted with non-network providers from our registry for possible solutions. However, in all cases, non-network providers were either unable to provide sufficient support to address the constraint, their business models did not fit the requirements of the solutions, or they did not present the highest net economic benefit in comparison to the proposed network option.

The STPIS risks are a relevant consideration because the reliability of non-network solutions are typically lower than network alternatives (e.g. the risk of an embedded generator failing when called upon is greater than the risk of a transformer failing). Accordingly, our demand side engagement strategy clearly sets out the payment principles we consider in discussions with embedded generators. These principles, which are consistent with those reflected in the Essential Services Commission of Victoria's Electricity Industry Guideline No. 15, include the following:

- limiting our exposure and customers to potential costs arising from the failure of a non-network solution to deliver the stated solution; and
- appropriate sharing of risks from any failure of the non-network solution.

Our experience through informal discussions with non-network proponents is that their limited willingness to satisfy these principles has contributed to non-network solutions not being proposed. We maintain that these principles are relevant to protect our customers from the risk of (potentially) unreliable non-network solutions.

The DER market is immature and networks don't yet have confidence in using them. Additionally some DER solutions provide option value which is difficult to value. Providing incentives for networks to procure DER solutions would help provide a kick-start to DER.