12 December 2016

Dr Ron Ben-David
Chairperson, Essential Services Commission
Level 37, 2 Lonsdale St
Melbourne, VIC 3000

Dear Dr Ben-David

Re: THE NETWORK VALUE OF DISTRIBUTED GENERATION, INQUIRY STAGE 2 DRAFT REPORT

CitiPower and Powercor welcome the opportunity to respond to the Essential Services Commission of Victoria's (**ESCV**) draft report on the network value of distributed generation. We support many of the ESCV's key findings, including that a broad feed-in tariff is not an appropriate mechanism to capture the variability in network value from distributed generation.

Our submission also demonstrates the following:

- a framework for grid services should be implemented through the National Electricity Rules (**Rules**), and the Australian Energy Market Commission's (**AEMC**) recently announced Distribution Market Model project which includes consideration of a grid service market;
- an efficient market for grid services requires efficient pricing signals, as well as consideration of the costs imposed by distributed generation;
- any network value provided by distributed generation is best calculated by distributors; and
- the existing regulatory framework already ensures networks have the right incentives to reward distributed generation where it adds value to the network. This includes the capital expenditure sharing scheme (**CESS**) and the publication of network limitations and planning information in the distribution annual planning report (**DAPR**) and the network opportunities map developed by the Institute for Sustainable Futures at the University of Technology Sydney. Under AEMC's new December 2016 rule on Local Generation Network Credits, DAPRs will soon be expanded to include more detailed information on system limitations under a uniform template.

Should the ESCV have any queries regarding this submission, please do not hesitate to contact Sonja Lekovic on
.

Yours sincerely,

Brent Cleeve
Head of Regulation, CitiPower and Powercor

Network value of distributed generation

The ESCV's draft report on the network value of distributed generation recognised that factors influencing the calculation of network value include location, time, asset life-cycle, capacity and optimisation. The ESCV also recognised that a broad-based feed-in-tariff was not an appropriate mechanism to remunerate network value. Instead, the ESCV is consulting further on whether network value can be better remunerated through an efficient market for grid services.

Our submission focuses on the key considerations that should be taken into account before a market for grid services is planned and designed. This includes the effectiveness of the existing regulatory framework.

Any market for grid services should be implemented through the Rules

On 1 December 2016, the Australian Energy Markets Commission (**AEMC**) released an approach paper on the distribution market model. The AEMC's paper is aimed at identifying the following:[1]

- what, if any, new roles, price signals and market platforms are required to optimise the development, deployment and use of distributed energy resources; and
- whether the existing electricity regulatory framework impedes or encourages innovation and adaptation by distributors to support the efficient uptake and use of distributed energy resources.

Through its consultation, the AEMC will be able to examine the viability of a grid services market and develop national mechanisms. We consider this framework is preferable to a Victorian-specific grid services market for the following reasons:

- national mechanisms are more likely to encompass feedback and experiences from a larger number of stakeholders and interests;
- although smart meters exist in Victoria now, the introduction of metering contestability in other jurisdictions will expand this infrastructure;
- the AEMC is consulting on, and implementing, a number of rule changes that affect the framework for distributed generation. As such, the AEMC is best placed to consider the inter-relationships of these rule changes in a more holistic manner; and
- the AEMC's review is focused on promoting the National Electricity Objective. In contrast, the ESCV is bound by the terms of reference which restricts a fulsome consideration of factors critical to an efficient market (e.g. consideration of costs and network pricing).

Efficient market for grid services requires cost-reflective tariffs and consideration of costs

Any consideration of an efficient market for grid services requires efficient pricing signals, as well as recognition of the costs imposed by distributed generation.

<u>Cost-reflective tariffs</u>

An efficient market for grid services must ensure any generation that reduces load is compensated at the efficient cost-reflective rate. While distributors are required to develop cost-reflective network tariffs, the Victorian Government determined that cost-reflective tariffs can only be introduced on an opt-in basis. In the absence of cost-reflective tariffs, some customers will be over-compensated, and other under-compensated, for load reduction. Additional mechanisms to properly compensate under-compensated customers will involve additional transaction costs, and there is unlikely to be any provision to claw back from over-compensated customers. Additionally, if distributed generators are efficiently compensated for their export, but not for their demand reduction, then their choices will be inefficient. For instance batteries would not be used optimally. Efficient prices are an essential prerequisite for a properly functioning grid services market.

[1] AEMC, *Distribution Market Model project*, Information sheet, 1 December 2016, p. 1.

Alignment of costs

We recognise that the ESCV's terms of reference excluded the consideration of the costs distributed generation imposes on our networks. These costs, however, must be reflected in an efficient market for grid services.

Any mechanism that excludes the calculation of costs would result in inefficiencies and the costs being smeared over the entire customer base. Inflated remuneration for distributed generators would also lead to inefficient decision making by the generator.

Firmness of supply

The ESCV's draft report also recognised the importance of firmness of supply to the network value of distributed generation. This availability of distributed generation when it is required by the grid must be accounted for in order to price grid services efficiently.

For example, table 1 shows the variability in output of solar PV at our Werribee zone substation during the ten highest demand days in the 2015–2016 summer. The demand reduction due to solar PV ranges from 1.2 to 9.2 megawatts (**MW**) demonstrating the challenges of relying on distributed generation to manage supply.

Table 1 Ten highest demand days at the Werribee zone substation over the 2015–2016 summer

Date	Actual max demand with solar PV (MW)	Max demand with no solar PV (MW)	Demand reduction due to solar PV (MW)
17 December 2015	83.4	89.8	6.4
19 December 2015	94.1	98.6	4.5
20 December 2015	85.4	91.1	5.8
31 December 2015	87.6	94.3	6.7
11 January 2016	76.9	81.8	4.9
13 January 2016	104.0	106.0	2.0
18 January 2016	81.0	90.2	9.2
23 February 2016	96.4	97.5	1.2
8 March 2016	94.4	98.5	4.2
17 March 2016	82.8	86.0	3.2

Source: Powercor Australia data.

Firmness of supply can be improved with batteries and other technologies that transform the generation from intermittent to firm. These capabilities would also need to be reflected in an efficient market for grid services.

Non-network solutions must be efficient

A market for grid services implies that distributors will be responsible for calculating the efficient value of grid services. We support such an approach, as distributors are best placed to understand network limitations and planned network investments, and are incentivised to implement optimal solutions at efficient prices.

For example, our previous submissions have set out how the existing regulatory framework already supports efficient investment (including in grid services). These mechanisms include the following:

- opportunities for distributed generation to contribute to alleviating network limitations as outlined in our DAPRs, demand side engagement strategies and the network opportunities map;
- probabilistic planning ensures the cost of removing network constraints are balanced against the value of customer reliability; and
- the CESS provides ongoing financial incentives to seek the least cost solution for network augmentation throughout a regulatory control period, be it network or non-network solutions.

The impacts of such mechanisms on our business practices, and how they have led to lower costs for our customers, are further demonstrated below.

<u>Network support payments</u>

Distributed generation has been engaged in cases where it is economically optimal to do so and when the type of engagement required suits the business model of the generator. For example, 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 (**CBD**). 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 distributed generation in that location was not sufficient to completely remove the need to augment the network.

<u>Regulatory investment tests</u>

As part of the regulatory investment test (**RIT-D**) process for a number of large projects recently, 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. A summary of the Melton/Bacchus Marsh project is provided in Appendix A.1, providing details on the consultation process.

<u>Demand forecasts in our regulatory proposals</u>

The existing regulatory framework also ensures the potential benefits that distributed generation may provide through the deferral of demand driven augmentation expenditure are realised. For example, deferred augmentation benefits from distributed generation are reflected in our regulatory proposals. Specifically, the demand forecasts used to determine our augmentation expenditure requirements for the 2016–2020 regulatory control period took into account predicted growth in distributed generation on our network (including from solar PV systems). Where growth in distributed generation has lowered our demand forecasts, such that network augmentation is no longer required to address a network constraint, this benefit will already be reflected through lower tariffs to all of our customers over the 2016–2020 regulatory control period.

<u>Demand management programmes</u>

As part of our business-as-usual practices, we maintain an efficient grid through demand management measures, which reduce peak demand and potentially lower the need for augmentation. For example, we diversify the time of switching 'on' of selected hot water units and slab heaters under controlled load network tariffs. This reduces the peak demand of the hot water and heating load. The 2016 Hot Water Demand Management Programme targeted highly loaded local distribution substations with circa 24,000 AMI meter modifications.

<u>Non-network solutions will need to evolve with technological change</u>

Our business has recognised that recent technological advances will open up new opportunities in demand management. A new group was recently established in our Network Business Unit to explore and take advantage of these new opportunities.

This group has information technology, metering, network control and analytics skills. Examples of areas of focus are:

- testing different behind-the-meter battery control regimes on network demand;
- investigating the control of air-conditioners and investigating techniques to identify customers with air-conditioners;
- assessing a load reduction rebate scheme;
- using inverters to manage voltage issues;

- planning for the installation of weather stations to measure solar radiation at each zone substation to better understand the contribution of solar PV; and
- discussions with non-network providers, including demand aggregators, to contribute to network constraints which fall outside the DAPR.

A.1 Melton and Bacchus Marsh case study

In 2014, we identified a network constraint on our Powercor network, at the Melton (**MLN**) and Bacchus Marsh (**BMH**) zone substations. We undertook a RIT-D for these network constraints, the results of which, including consideration of non-network options, are summarised in this case study.

Identified constraints

We identified the following constraints at the two zone substations:

- both were loaded above the station N-1 cyclic rating, putting customers at risk of supply interruptions;
- by 2020, at the 10 per cent maximum demand level, both would experience insufficient capacity to supply peak demand with all plants in service;
- at the 50 per cent load forecast, with one transformer out of service (N-1 rating), customers would face a supply interruption due to insufficient capacity at both substations unless action was taken to reduce demand or increase capacity;
- only limited load transfer capability existed between the MLN zone substation and the neighbouring zone substations at BMH and Sunshine (**SU**) and between BMH and Ballarat North (**BAN**). As a result, customers could potentially be left without supply until capacity in the neighbouring network becomes available;
- strong load growth was expected in the Rockbank East, Plumpton and Koroit areas following the release of the new Precinct Structure Plans by the Melbourne Planning Authority; and
- the forecast peak demand at BMH zone substation was expected to also cause the Brooklyn terminal station (**BLTS**)-BMH 66kV sub-transmission line to exceed its N line rating under system normal conditions during the 2016-2017 summer.

Non-network solutions assessment

The identified network constraints were first discussed in our non-network options report, published in August 2014. The report detailed several network options on how to address the identified need and we invited feedback from stakeholders, including non-network providers, on possible options to address the identified need.

We received only a limited number of informal enquires from non-network providers in response to this report. As a result we extended the closure of the consultation period from November 2014 to early 2015 to allow interested parties greater time to develop responses. In the end, no formal submissions were received during this period.

In January 2016, we published the draft project assessment report setting out a range of credible options considered to address the identified need, as well as our preferred network option. We sought feedback from stakeholders on our draft report, and extended the response time for submissions to 18 March 2016.

During this consultation period, we met with two potential non-network proponents to discuss the details of the report. One formal submission was received from Greensync Pty Ltd (**Greensync**). The Greensync non-network proposal planned to address the N rating issue of the BLTS-BMH 66kV line via targeted demand management of commercial/industrial and small business customers supplied from BMH zone substation. This had the additional benefit that it would be available for the N-1 constraint at BMH as well.

However, subsequent to Greensync's submission, discussions between Powercor and Australian Energy Market Operators (**AEMO**) took place, regarding the possibility of extended operational closing of the BLTS-BMH-BATS (Ballarat terminal station) 66kV loop when the BLTS-BMH 66kV N rating was close to being reached. Following system studies, operational checks and the definition of suitable operational safeguards with AEMO, permission was granted to close the loop during periods of peak demand at BMH. This new operational procedure alleviated the N rating sub-transmission constraint.

Preferred option

On the basis of the net economic benefit analysis conducted as part of the RIT-D, the most economic option is a network solution with the following technical characteristics:

- installing a third transformer (25/33 MVA), with a fourth 66kV circuit breaker and a third 22 kV indoor bus at MLN at an estimated cost of $6 million; and
- installing a new 22kV distribution feeder and tie into the existing MLN network, at an estimated cost of $1.8 million; and
- transfer 5MW of existing BMH customers onto the new MLN feeder to relieve the load at risk at BMH zone substation.