24 November 2016

Mr Richard Owens
Senior Director
Australian Energy Market Commission
PO Box A2449
Sydney South, NSW 1235

Email: richard.owens@aemc.gov.au

Dear Mr Owens

RE: Replacement expenditure planning arrangements consultation paper - ERC0209

CitiPower and Powercor Australia (**the Businesses**) welcome the opportunity to respond to the Australian Energy Market Commission's (**AEMC**) consultation paper on the Replacement Expenditure Planning Arrangements. Our submission responds to the questions raised in the AEMC's consultation paper, with regard to the existing and proposed reporting on asset retirements and consideration of non-network alternatives, and the proposal to extend the regulatory investment test for distributors (**RIT-Ds**) to replacement projects. The submission demonstrates the following key points:

- we support the need for transparency and visibility of the asset replacement projects on the network, for the benefit of key energy stakeholders and potential non-network solutions providers;
- our investment decisions, for both network augmentation and asset replacement, are based on our long term strategy of improving efficiency and reducing network tariffs, and non-network solutions are already an integral part of the cost/benefit analysis;
- we apply best-practice condition-based risk management (**CBRM**) (replacing assets based on condition rather than age) and probabilistic planning (investing when there is a high probability of failure risk), which has resulted in Victorian distributors being the most efficient network businesses in Australia;
- the regulatory framework already provides a range of incentives that stimulate distributors to consider non-network solutions and provide benefits to consumers—for example, the Capital Expenditure Sharing Scheme (**CESS**), the effects of which will be realised over the current regulatory period;
- we believe that existing annual reporting requirements provide sufficient information on our network limitations and potential for non-network solutions, and that the additional operational burden of RIT-Ds for replacement projects should be weighed against the expected incremental benefit to consumers; and
- ultimately, non-network solutions, including for replacement expenditure, need to be efficient.

In our submission, we have responded to a number of questions raised by the AEMC in its consultation paper and have explained the reasoning behind our position in this matter. If you have any queries regarding this submission please do not hesitate to contact Sonja Lekovic on (03) 9683 4784, or slekovic@powercor.com.au.

Regards

Renate Vogt
Head of Regulation, CitiPower and Powercor

Response to questions set out in the AEMC's consultation paper

1.1 Key issues the rule change is seeking to address

1.1.1 Are non-network solutions a viable alternative to replacing network assets on a like-for-like basis and how does this differ from the potential for a non-network solution to provide a viable alternative to augmenting the network?

Non-network solutions can be a commercially viable alternative to both network augmentations and asset replacement, if the non-network solution contributes to peak load management at a lower cost compared to a network solution. However, for the vast majority of assets, non-network alternatives are not viable, such as circuit breakers which perform a network function rather than provide or alter capacity, and investment in the replacement of these assets is viewed incontestable at present.

Our experience

Our investment decisions, for both network augmentation and replacement of assets, are based on our long term strategy of improving efficiency and reducing network tariffs. We apply the best-practice CBRM processes and probabilistic planning, and we are incentivised to invest efficiently through a range of schemes, including:

- only receiving cost recovery for the efficient capex cost of a prudent operator;[1] and
- direct incentives to make only efficient capex decisions through the CESS.

From our perspective, it is neither prudent nor in our commercial interest to grow the regulatory asset base (**RAB**) and to make inefficient investments that increase network costs, and we already consider non-network solutions before undertaking replacement capital expenditure.

However, non-network solutions have typically been more expensive than network options for the types of network limitations that we have experienced. For example, as outlined in appendix A.1, we considered investing in a 10MVA gas fired embedded generation unit to relieve network constraints affecting the Geelong East zone substation (**GLE**). This project would likely have delayed the need for a second upgrade to transformer capacity from 2017 to 2025, and depending on the investment, possibly also the first transformer upgrade from 2016 to 2020. The costs of the GLE generation unit, however, were $3.7 million higher than the network solution. This differential reflects payments for the embedded generator, as well as the additional connection works required to our network to implement this alternative. In most circumstances, including the GLE example, the costs of such connection works are material.

1.1.2 Are the current annual planning reporting requirements in the NER relevant and likely to be useful for replacement expenditure? If any, where are the gaps in the current annual planning reporting requirements in the NER for replacement expenditure?

The current planning reporting requirements, through the Annual Planning Report (**APR**) in conjunction with the three-year Demand Side Engagement Strategy (**DSES**), are sufficient tools and indicators of key network limitations. The APR estimates the expected capacity and demand at each zone substation and on each sub-transmission line over the next five years and provides a summary of major works being proposed on the network, including replacement of assets valued over $2 million, over the same five-year period. These reports are available on our website with a dedicated page on Demand Management.

We also maintain registers on our dedicated Demand Management websites, for parties to notify their interest in being advised of developments relating to the network planning. The notification to parties includes published information regarding any non-network options and the APR, as well as any other relevant publications. We use

[1] NER, 6.5.7 (c).

this register not only to consult with interested parties, but also to determine their level of interest and ability to participate in the development of non-network options.

We are increasing visibility on network limitations. The Institute for Sustainable Futures at the University of Technology Sydney has developed a set of interactive maps on existing and future planned network capacity constraints across Australia, including information on network opportunities for non-network solutions providers that that was not previously available in a consistent manner across the country.

Additionally, the AEMC's draft rule for its local generation network credit rule change review also proposes to introduce a systems limitations report that would complement the APR. The draft rule would require distributors to annually complete a ‘system limitation report’ with information on the limitation and proposed solutions.

1.1.3 What do NSPs currently do to plan for asset replacement in practice and to what extent does this address the perceived problems identified by the AER?

Our replacement expenditure is primarily driven by the condition of the asset, rather than age. For large asset replacement projects, such as zone substation transformers and switchgear, we use CBRM to most efficiently estimate the necessary retirement of the asset. The CBRM methodology assesses the condition of assets, including the risk of deterioration, and uses probabilistic planning to determine the probability and consequences of failure. Smaller routine asset replacements, such as poles, pole top-equipment, crossarms, insulators and batteries, are assessed based on the principles of Reliability Centred Maintenance (**RCM**) together with regulatory obligations that are built into the asset management procedures.[2] These best practices have resulted in Victorian distributors being the most efficient network businesses in Australia.

We also have processes in place to ensure efficiency of an investment in the network constraint for both augmentation and asset replacement. Where the estimated capital cost to address the constraint is likely to be less than $5 million, or the project meets the exceptions to the RIT-D (such as asset replacement), a streamlined process is adopted, which consists of:[3]

- screening process for non-network options;
- investigation into network and non-network options; and
- assessment of preferred option to meet identified need.

The investment decision is made on cost efficiency, and as our mentioned experience shows, non-network solutions have fallen short of being the most efficient option. As other investment opportunities arise, non-network solutions will continue to be considered for potential augmentation and replacement projects, but will only be selected if they prove to be more efficient than network solutions.

All major replacement projects selected through CBRM and RCM are reported annually in the APR including options for replacement. We believe that these reports provide sufficient information for interested key energy stakeholders, and hence address the perceived problems raised by the Australian Energy Regulator (**AER**).

1.2 Annual planning reporting on retirements and de-rating

1.2.1 To what extent would the proposed information to be reported in the APRs be useful for energy market stakeholders, including non-network service providers, network service providers, connection applicants and the AER, and why?

As mentioned earlier, we believe that the existing level of reporting by the distributors in APRs is sufficient in informing key energy stakeholders about the major network limitations and planned investment in both augmentation and replacement over the medium-term. Additionally, the AEMC's draft rule for its local generation network credit rule change review also proposes to introduce a systems limitations report, including planned replacement projects, which would complement the APR. The information provided in the APRs and the

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[2] CitiPower (2015), Regulatory Proposal 2016-2020, April.

[3] CitiPower and Powercor (2016), Demand Side Engagement Strategy, v2, p. 14-25, July 25.

system limitations reports already covers all the information necessary for key energy stakeholders to learn about potential areas of investment. An additional requirement to list all asset retirements and de-ratings could lead to inefficiencies as we may decide to retire or de-rate assets without a need for replacement or further investment.

We also consider that the existing regulatory regime already provides sufficient incentives to distributors and non-network service providers, to balance the benefits and costs of each investment. Among other incentives including benchmarking, the recently established CESS is particularly aimed at improving the efficiency of capital expenditure by distributors, by rewarding efficiency improvements and penalising inefficiencies. The CESS is spread evenly over the current regulatory period to 2020, during which considerations for non-network alternatives in examination of most efficient options will be paramount. The CESS impacts should be allowed to play out before additional regulations are potentially imposed.

1.2.2 Is it appropriate that the scope of the new reporting requirements include planned asset de-ratings as well as planned retirements? To what extent does this add to the administrative burden for NSPs?

We believe that the current reporting of network limitations to be sufficient. However, should the additional reporting requirements on listing asset retirements and/or de-ratings be introduced, we suggest this only apply to those assets where the cost of replacement would be more than $5 million and where there may exist viable possibility of efficient non-network alternatives (rather than those where the most viable option is like-for-like replacement), in line with the proposed requirements for RIT-Ds for asset replacement. This will mitigate the risk of significant additional burdens in our reporting requirements.

1.2.3 Should all assets be reported on by NSPs in their annual planning report or are only certain asset types relevant? What types of asset should be subject to reporting requirements by NSPs and what should not?

If additional reporting requirements were to be introduced, the reporting should provide a minimal increase in the cost and administrative burden by limiting the assets to be reported on. However, defining a set of certain asset types to be reported on can be difficult, as the basis for defining the asset type subset as requiring like-for-like replacement can change over time as a larger variety of non-network solutions arise. Even if the list was to be updated periodically, it may be out of date when new network alternatives arise and this could lead to missed opportunities from the time when the non-network solutions is developed to when the list is updated. We believe that it is more judicious that, should the new reporting requirements be introduced, the assets to be reported on are limited to larger projects over the value of $5 million, for which the assets owners will need to determine if the assets either require like-for-like replacement without sufficient competing technologies or "assets which are replaced as part of a broader asset management program, such as the replacement of 'end of life' poles across the network"[4].

1.2.4 Is the proposed AER network retirement reporting guideline the appropriate means of requiring NSPs to report on certain asset types and not others or would an alternative mechanism be more appropriate? If an AER guideline is appropriate, what should it contain and how should the AER be guided in its development? In addition, what would be the appropriate process be to make and review an AER guideline?

As mentioned above, we are already highly incentivised to invest efficiently and consider all available options that reduce network costs. In this regard, network asset retirement guidelines by the AER are not necessary as each business will make case-by-case informed decisions given the specific characteristics of their network and asset stock.

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[4] Australian Energy Regulator (2016), Request for Rule Change - Replacement expenditure planning arrangements, submission to the AEMC, p.15-16, June 30.

1.2.5 Should the AER guideline also set out principles and a broad approach that NSPs must follow in deciding whether to plan to retire assets? What should these principles and the broad approach be?

The AER is an economic regulator whose role is to incentivise distributors to invest efficiently and maintain reliability, security and safety of supply. The AER does not have a role in making business decisions regarding the operations of the network, including asset retirement and replacement. As such, the basis for, and the decision to retire assets must remain a decision for the asset owner who understands the technical, safety and business requirements. These decisions are made on a case-by-case basis through appropriate cost/benefit/risk analysis. We use well regarded CBRM and probabilistic planning, taking into account each asset's unique specifics regarding its make, age, functionalities, the load it has been subjected to, etc., to determine the end of its technical life. These practices have resulted in Victorian distributors being the most efficient distribution businesses in Australia.

1.2.6 Compared to the current arrangements, how much additional reporting by NSPs would be required under the AER's proposal? What would be the impact on NSPs?

Our reporting requirements in producing the APRs and the DSES, are reasonably high, in addition to the detailed cost/benefit analysis of network limitations leading to both augmentation and asset replacement. It is unclear yet how much additional reporting would be required under the proposed change as inefficiencies in reporting are likely to arise if additional information is required on planned asset retirements and de-ratings that do not contribute to system limitations. It is therefore critical that the cost of additional reporting requirements should be lower than the additional benefit to consumers. However, this is unlikely given the significant benefit to consumers from existing practices and incentives that promote efficient investment.

1.3 Application of RITs to replacement expenditure

1.3.1 Will extending the regulatory investment tests to replacement capital expenditure benefit energy market stakeholders, including non-network service providers, network service providers and the AER, and why?

The key consideration in deciding whether to extend the formal RIT-D process (rather than the cost/benefit analysis we already undertake) to replacement capital expenditure should be an analysis of potential operational risk that we will undertake in delaying projects to complete RIT-Ds, compared to the benefit of additional information provided to key energy stakeholders and ultimately its benefit to consumers.

The most significant cost to RIT-Ds is the delay in implementation of projects while the test is carried out, potentially leading to disruptions in the system. We have a number of replacement projects exceeding the $5 million value in the pipeline over the medium term, and delays in the implementation of the RIT-Ds could potentially impact our performance. Cost calculations to be compared to the potential benefits should consider these factors along with the financial cost of RIT-Ds.

Taking these costs into account, it is unclear to us at this stage whether the suggested benefits of the RIT-Ds would outweigh the operational burden involved. As previously mentioned, our annual planning reporting provides significant and sufficient information on large replacement projects, which have already sparked interest and subsequent consultations with non-network service providers. Equally, in our standard business practices and through existing incentives, non-network providers are regularly consulted on larger investment projects and have been provided information sufficient for them to compete in the market.

The AEMC's draft rule on the local generation network credits also requires distributors to identify the dollar value for each year of deferral for given system limitations. Should this rule change be introduced, we believe that this information would be more useful for demand-side management proposals than RIT-Ds for replacement expenditure would be for identifying non-network opportunities.

Therefore, we do not consider that the RIT-Ds should be extended to replacement capital expenditure as the benefit to consumers is unlikely to outweigh the additional operating burden. However, if the test were to be introduced, it is critical that the test be limited in time and scope so that they do not delay pending investments, which would create significant network reliability and security risks.

1.3.2 Should the regulatory investment tests also apply to maintenance and refurbishment expenditure or should these categories of expenditure continue to be exempt from the tests?

We believe that the maintenance and refurbishment expenditure should continue to be exempt from the tests, as these projects are unlikely to be significantly large while the reporting on the expected maintenance and refurbishment would add more administrative burden and cost to the distributors for no added consumer benefit.

1.3.3 Should the cost thresholds for asset replacement projects be the same as cost thresholds for network augmentation projects?

The cost thresholds for asset replacement projects should be high enough so that it only incorporates projects that are likely to have a competitive alternative without creating a significant administrative, operational and financial burden on the distributors. Additionally, given expectations for replacement instead of augmentation capital expenditure projects to be the main driver of future capex moving forward, we support the proposal for the cost threshold to be no lower than $5 million—the current threshold for augmentation projects.

1.3.4 Is it appropriate for a regulatory investment test to not be required where an NSP considers a like-for-like replacement of the asset is the only option to address the problem?

We believe that the RIT-Ds create an additional operational burden to distributors and therefore support AER's proposition to, should the tests be introduced, reduce this burden by eliminating the need to carry out tests on assets that are unlikely to have competitive non-network alternatives and where the individual replacement projects are part of a larger replacement programme.

1.3.5 Is the proposed requirement for NSPs to publish an exemption report where there is no alternative to like-for-like replacement appropriate? Do the benefits of this mechanism outweigh the administrative costs that it may impose? Is there an alternative mechanism which would be more appropriate?

Producing exemption reports for investment in asset replacement that is classified as like-for-like without significant alternatives would add to our administrative burden and operations cost. In order to reduce this burden, we suggest that should the proposed changes to RIT-Ds be implemented, the like-for-like investment exemption should be summarised in the APRs. The APRs provide an overview of planned large replacement projects resulting from network limitations, including explanations for not considering other options where that is the case. Adding a summary of the reasoning behind classifying an asset as like-for-like would ensure that all the information is kept in the same report and as part of a bigger picture.

1.3.6 What information should NSPs be required to provide in an exemption report? Is it appropriate that an NSP has to provide a summary of an exemption report to AEMO within five business days and to interested parties, on request, within three business days? Do stakeholders agree that AEMO must publish the exemption report on its website within three business days?

As explained in the previous question, we believe that reporting on the like-for-like investment exemption should be limited to summaries in APRs, in order to limit related administrative costs.

1.3.7 Is it appropriate that parties can raise a formal dispute with the AER on the conclusions of an exemption report published by an NSP? Is 30 business days, as proposed, the appropriate timeframe for allowing interested parties to raise a dispute with the AER? Is 31 business days after publication of an exemption report the appropriate timeframe for an NSP to wait to undertake a like-for-like replacement where no dispute is raised? If an exemption report is determined by the AER to be non-compliant, should the NER explicitly exclude an NSP from being relying on the report to carry out a like-for-like replacement?

In order to avoid potential delays and operational risks by not implementing planned projects, we believe that the length of the dispute process should be kept to a minimum. Additionally, significant operational risks may be associated with the NER excluding the distributor from relying on the decision to carry out the like-for-like replacement, particularly for assets with nearing retirements. These risks should be mitigated by allowing for projects with a certain level of urgency to go ahead despite the disputed outcome.

1.3.8 Are the additional changes proposed by the AER appropriate and useful to stakeholders? What compliance burden would arise for NSPs? As these requirements currently apply in a limited way in the NER, how useful have they been to date?

The four other AEMC rule change requests regarding non-network solutions are in many ways entwined and show the fast-changing environment that the distributors are currently operating in, particularly the vast interest energy stakeholders have in finding efficient non-network alternatives. We are adjusting to the changing environment and are actively doing work that helps us better understand what the most efficient role of those solutions are and where their cost competitiveness lies.

However, we believe that there are some redundancies between the rule change proposals, one being the systems limitations report (response in question 1.1.4) which asks for some of the same information as the additional reporting information proposed in this rule change. In the interest of reducing the burden on the distributors and streamlining the rule changes, it would be prudent to allow other rule change processes to play out before seeking additional regulations in this area.

1.3.9 What transitional arrangements should be put in place to allow NSPs and the AER to be able to comply with the proposed rule if it were to be made?

We do not consider that the proposed changes should be put in place. However, if the AEMC decides to implement the rule change, it should apply to the next determination period as the increased financial, administrative and operational burden of the APRs and the RIT-Ds cause delays in the implementation of already planned projects.

A.1 Demand management case study

This appendix sets out our experience with regard to a key demand management solution we have recently considered implementing in Geelong.

A.1.1 Embedded generation in Geelong

In 2014, we proposed for consideration of an investment in a 10MVA gas fired embedded generation unit to relieve network constraints affecting the Geelong East zone substation (GLE). This project would have likely delayed the need for a second upgrade to transformer capacity from 2017 to 2025, and depending on the investment, possibly also the first transformer upgrade from 2016 to 2020.

This and other investments were assessed in the RIT-D. Of all the investments considered, an investment in embedded generation was estimated to deliver a total present value of market benefits $2.5 million higher than the pure reliance on transformer upgrades ($255.8 million versus $253.3 million). However, because the costs of the embedded generator were $3.7 million higher, total net benefits were $1.2 million lower ($242.6 million versus $243.8 million).

Our experience with GLE is typical of many of the non-network options we have considered. Further, there are reasons to believe that the standard application of the RIT-D may not always lead to the most efficient investment. An important reason is that under the RIT-D it is difficult to place a value on the options created by the deferral of large investments in traditional 'poles and wires'.

As already noted, in the specific context of the GLE, investing in embedded generation was estimated to delay costly upgrades from 2017 to 2025. The benefits of this delay were estimated on the basis that technology would more or less 'stand still' between now and 2025 so that, ultimately, the costly upgrade to the transformers would happen. However, the pace of technological change, including in solar generation and battery storage, is such that there is a non-zero probability that the upgrade of transformers would have been delayed further—or conceivably avoided completely—by new investments in technology available in 2025 but not known at the time of the RIT-D.

That is, investing in embedded generation, by deferring expensive network solutions, creates 'option value' in that it creates the potential to benefit from further technological innovation and change that is likely to occur in the meantime. This might allow the expensive network solution to be:

- further delayed by new investments in (currently) innovative services;
- resized; or
- avoided entirely.

This option value is not generally given any weight in application of the RIT-D and, therefore, investments in innovative solutions to defer investment tend to be undervalued.