Jemena Electricity Networks (Vic) Ltd

Submission on AER Consultation Paper

Demand management incentive scheme and innovation allowance mechanism

Public

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OVERVIEW

Jemena Electricity Networks (Vic) Ltd (**JEN**) welcomes the opportunity to comment on the Australian Energy Regulator's (**AER's**) consultation paper on the demand management incentive scheme (the **Scheme**) and innovation allowance mechanism (the **Allowance Mechanism**).

Jemena has been actively engaged in the AER's consultation process since it commenced in September 2016, and looks forward to ongoing dialogue and participation in the development of the scheme design.

JEN supports the ENA's submission

JEN supports the Energy Networks Australia (**ENA's**) submission on the AER's consultation paper. Rather than repeat the feedback provided by the ENA, our submission focusses on points that we wish to emphasise or those not covered by the ENA.

Specifically, we support the ENA's position on:

1. *The scope of the Scheme*—specifically, that the scope of eligible projects should be interpreted as broadly as possible.
2. *Exploring the net-market benefit sharing mechanism further*—noting that this is a requirement of the rules.
3. *Its concern with Allowance Mechanisms which would exclude distributors from implementing innovative demand management research and development projects*—given that distributors' experience is crucial to achieving successful innovation and applying it in business as usual processes.

In addition we also wish to emphasise the following significant points

1. *The type and scope of demand management providers should not be mandated by the Scheme*. We do not consider it appropriate to apply a specific criterion aimed at assessing whether the proposed Scheme enhances competition. The focus of the Scheme should be to maximise the net benefits to network customers, irrespective of how the demand management solutions are procured.
2. *A Scheme design which targets potential disincentives and facilitates net-market benefit sharing is likely to best meet the demand management incentive scheme objective*.
3. An Allowance Mechanism which sets *an adequate baseline allowance for distributors to pursue and deliver innovative projects, coupled with a bidding mechanism to encourage 'ground-breaking' R&D* is most likely to achieve the Allowance Mechanism objective.
4. *The scope and format of any additional reporting* required by distributors as part of the Scheme and Allowance Mechanism must be carefully formulated to ensure that it is fit for purpose, and that data requests are targeted in such a way as to avoid duplication, and minimise the cost to consumers.

1. RESPONSE TO CONSULTATION QUESTIONS

1.1 APPLICATION OF THE NEW RULE

Question 1: Do stakeholders support our interpretation and proposed implementation of the new rules? If you have alternative views, please share these and provide supporting evidence.

Jemena supports some aspects of the AER's interpretation and proposed implementation of the new rules, although further detail and clarification on a number of key aspects of the AER's proposal is required to better understand how it intends to implement the new rules.

Further clarification of what constitutes a non-network asset is required

Further clarification of what constitutes a non-network asset is necessary to understand the scope of the new Scheme. The AER defines non-network assets as those 'assets that are not used to convey or control the conveyance of electricity to customers, and that are not connection assets.'[1] However, it is not currently clear how it will apply this definition in practice. For example:

- Would expenditure on control systems that are used to enable non-network solutions, but are also used for the control the conveyance of electricity to customers, qualify as a non-network option under the Scheme?
- What amount or proportion of expenditure on network assets will be permitted under the Scheme?

It is important that the Scheme appropriately recognises that expenditure on network assets will be required to integrate non-network solutions into distributors' network operations. For example, non-network demand management solutions will rely on control systems that continually monitor the quantity of demand response capability embedded in different parts of the distribution network (e.g. to monitor the state of charge of grid support battery storage systems). The control systems will also be required to initiate demand responses, and have the capability to measure and verify the amount of demand response that has been dispatched for the purposes of calculating payments to demand management suppliers. It is conceivable that simple, stand-alone, control systems provided by demand management suppliers may be installed initially, as non-network solutions are rolled out. However, there will come a time when the demand response of the network (or network segments) has been built up to such an extent that it will be necessary to extend the distributor's overarching control systems to incorporate these stand-alone control systems. For example, our Distribution Management System, which is primarily used for distribution purposes, would need to be upgraded to integrate with these stand-alone systems. This might involve a system upgrade or the purchase of a new software module. The timing of such an upgrade is likely to be guided by the timing of the upgrade to the Distribution Management System, and could be undertaken separately to the implementation of a non-network solution. We consider that the expenditure to upgrade the Distribution Management System to appropriately interface with non-network solutions should qualify under this Scheme, irrespective of whether it is undertaken in conjunction with a specific non-network project.

[1] AER, *Consultation paper – Demand management incentive scheme and innovation allowance mechanism*, January 2017 (**Consultation paper**), section 4.3, page 4-20.

The type of Demand Management providers should not be mandated by the Scheme

In relation to the interface between the ring-fencing guidelines and the scope of the Scheme,[2] Jemena is of the view that the Scheme must be open to demand management solutions that are provided by appropriately ring-fenced affiliated entities. If the demand management incentive scheme objective is to be met, the Scheme must be indifferent as to whether demand management solutions are provided by affiliated entities or third party providers. If this is not the case, there is a risk that efficient non-network options brought to market by affiliated entities will be locked out of the Scheme. This is clearly inconsistent with the demand management incentive scheme objective, and the long term interest of consumers.

In this context, it is unclear why the AER intends to apply a specific criterion aimed at assessing whether the proposed Scheme enhances competition.[3] A more appropriate assessment would consider the effectiveness of the Scheme at promoting distributors to undertake demand management projects which maximise the net benefits to network customers, irrespective of how they are procured. We consider that the AER's recently released ring-fencing guideline,[4] which is designed to address concerns of cross subsidy and network behaviours in the provision of electricity services, is the appropriate mechanism in which to include the rules for related party services, not the demand management incentive scheme.

We accept the exclusion of voltage control and power factor correction projects

We accept the AER's interpretation that the scope of the new Scheme should exclude voltage control projects and power factor correction projects.

1.2 DEMAND MANAGEMENT INCENTIVES

Question 2: Do you agree with our view on the main demand management incentives (or disincentives) provided under the regulatory framework and the potential issues associated with these incentives? Please provide reasons to support any alternative views you may have.

Incentives to maintain or improve service levels (STPIS)

As noted in the consultation paper, a key disincentive to distributors in undertaking non-network solutions is the financial penalties that apply under the STPIS.[5] Demand management solutions are inherently less reliable than network solutions—until this is adequately recognised within the regulatory framework, the uptake of demand management solutions will be limited. For example, non-network solutions involving installation of batteries behind the meter to reduce network constraints rely on consumers or third parties to keep the batteries in good working order, and available to feed into the network as needed. As distributors have no visibility of whether the batteries are appropriately maintained or in good working order, it is very difficult to forecast with any certainty the reliability of these non-network solutions. If the output of the batteries is lower than forecast or more intermittent than expected, network businesses are at a greater risk of incurring STPIS penalties.

The most effective way of overcoming this disincentive is to exclude events resulting from failures of demand response solutions from the STPIS. The exclusion of such events will overcome barriers that distributors may face in passing on the risk to third party demand management providers who may be unwilling or unable to take on such risk. Jemena agrees that it would only be appropriate to exclude supply interruptions due to non-

[2] As discussed in section 4.4 of the Consultation paper.

[3] The AER's additional criteria to help give effect to the rules are detailed in Table 2 and Table 3 of the AER consultation paper.

[4] AER, *Ring-Fencing Guideline – Electricity Distribution*, November 2016

performance where reasonable best efforts are made to ensure that projects deliver their forecast level of demand management.

Current information provision requirements

Jemena acknowledges that an information asymmetry exists between distributors and third party demand management providers in relation to network constraints.[6] While the Planning Framework aims to address this information asymmetry, we recognise that there may be scope for further improvement. The recent Local Generation Network Credits (**LGNC**) rule change[7] will go some way to addressing the information asymmetry, with its requirement for distributors to publish a 'system limitations' report. However, some time is required for the benefits of the additional reporting to be realised.

A significant amount of information on network constraints is already published by distributors. An example of the information already provided on network constraints is provided below. This data is provided by JEN as part of the Distribution Annual Planning Report (**DAPR**), which is published annually.[8]

Table 5–78: Sunbury Zone Substation loading risk and limitation cost

	2017	2018	2019	2020	2021
10% POE MD (MVA)	43.1	44.0	45.2	46.4	46.9
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	163%	167%	171%	176%	177%
Max load at risk (MVA)	16.7	17.6	18.8	20.0	20.5
Hours at risk (h)	595	680	806	944	985
EUSE (MWh)	150.3	205.5	318.0	510.1	583.3
Cost of EUSE ($ thousand)	5,926.7	8,104.8	12,540.2	20,116.5	23,006.7

As presented in Table 5–78, a load reduction of 16.7 MVA in 2017 would defer any forecast limitation by 12 months.

Before embarking on the design of a Scheme which increases the reporting required by distributors, it is important to recognise expenditure will be required to update existing reporting systems, processes, portals and websites to provide additional information and data to third party demand management providers. It is therefore essential that the scope and format of any additional reporting required by distributors is carefully formulated to ensure that it is fit for purpose, and that data requests are targeted in such a way as to avoid duplication, and minimise the reporting effort.

Requirements to send cost-reflective price signals

We strongly support the move towards cost-reflective pricing, as it is the most efficient and effective means of reducing network demand. Whilst JEN has introduced cost reflective price signals as a part of the network tariff rule change[9] to its large business customers; jurisdictional restrictions on network tariff assignment for small

6 AER, *Consultation paper – Demand management incentive scheme and innovation allowance mechanism*, January 2017, section 5.5, pages 5-32 to 5-33.

7 AEMC, *Final rule determination: National Electricity Amendment (Local Generation Network Credits) Rule 2016*, December 2016.

8 Extract from *Jemena Electricity Networks (Vic) Ltd, 2016 Distribution Annual Planning Report*.

9 AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014.

customers[10] have inhibited their roll-out and effectiveness. JEN will undertake further activities—including broader consultation—to encourage the lifting of network tariff restrictions thus providing better price signals to our customers for the encouragement of demand management signals.

1.3 POTENTIAL DEMAND MANAGEMENT INCENTIVE SCHEME DESIGN OPTIONS

> Question 3: Do you see value in exploring this [net-market benefit sharing] option further, despite the difficulties associated with measuring net-market benefits? If yes, what detail of guidance should we provide on calculating market-wide costs and benefits? Should we (and if so, how should we) establish a method for valuing smaller demand management projects in a way that reduces the administrative burden of applying the Scheme to these projects?

We support the ENA's position in further exploring the net-market benefit sharing option. The inability of distributors to realise benefits accruing to other parts of the electricity value chain adversely impacts the competitiveness of demand management solutions when assessed against network based solutions.

While we recognise the challenges associated with monetising economic benefits accrued at other parts of the electricity value chain,[11] these are no greater than those likely to be encountered in designing the other Scheme options identified in the Consultation paper.

For a net-market benefit sharing Scheme to be successful, it will be critical to ensure that the Scheme is simple in its design and application, and that clear guidance is provided on the scheme, together with examples of how it should apply under various scenarios.

> Question 4: Since the RIT–D already requires distributors to select the option with the highest total market benefit, should we (and if so, how should we) treat RIT–D projects differently under this type of Scheme?

Without further information on what the AER has in mind for the treatment of RIT-D projects under the Scheme, it is difficult to provide a meaningful response to this question. However, prima facie we do not consider that RIT-D projects should be treated any differently to other projects under this Scheme. At Jemena, we identify and evaluate non-network solutions for all projects we undertake to address constraints within our network. The only difference with RIT-D projects is the requirement to publish our reports and analysis. If the Scheme is to achieve the demand management incentive scheme objective, it should be indifferent as to whether or not a project meets the RIT-D threshold.

> Question 5: How might we best combine the mechanisms discussed in section 6 above into an option that achieves the Scheme's objective? If you prefer a mechanism that we did not discuss in in section 6, please provide details on this mechanism

A Scheme design which targets potential disincentives and facilitates net-market benefit sharing is likely to best meet the Scheme's objective.

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10 Victorian Government, *Advanced Metering Infrastructure (Ami Tariffs) Amendment Order 2016, Order in Council, Victorian Government Gazette G15*, 14 April 2016.

11 AER, *Consultation paper – Demand management incentive scheme and innovation allowance mechanism*, January 2017, section 5.4.1, page 5-31.

As previously discussed, excluding STPIS penalties associated demand management projects would overcome a significant barrier to the uptake of non-network solutions for demand management. Enabling distributors to realise a fair proportion of the benefits accruing to other parts of the electricity value chain, and/or the benefits accruing by deferring capital expenditure would be effective in encouraging the uptake of non-network solutions for demand management.

> Question 6: If you have views against applying any of the particular mechanisms discussed in section 6, please provide reasons to support this view.

Type 3: Mechanisms to promote competition

We acknowledge that third parties should be provided with equal access opportunities to propose and deliver demand management solutions, and the mechanisms to facilitate this (e.g. standard form of contracts, provision of information). The aim of the Scheme should be to deliver projects in the most prudent and efficient manner, with the greatest net benefit to customers, irrespective of whether they are delivered by third party demand management providers or by affiliated entities.

Type 4: Targets for demand management deployment

We caution the AER against adopting a Scheme design which sets distributors targets for demand management deployment. A Scheme which sets targets for demand management deployment is unlikely to achieve the demand management incentive scheme objective, which is to provide distributors with an incentive to undertake <u>efficient</u> expenditure on relevant non-network options. This is because the targets, if set incorrectly, may actually encourage distributors to undertake either too much or too little investment on non-network demand management solutions.

In addition, the mechanics of the scheme described in the Consultation paper, which would involve setting a baseline peak demand reduction target, and then making annual adjustments to the targets for a number of variables, would introduce complexity, subjectivity and uncertainty into the design and operation of the Scheme.

It is unclear how the long term interests of consumers could be served by such a mechanism, given the risk of targets being set either too low or too high.

> Question 7: How might we best give effect to or enhance the information and reporting requirements discussed in section 6.5?

All of the mechanisms proposed by the AER will impose pre and post-project reporting requirements on distributors, the extent of which will vary with the complexity of the mechanisms.

In establishing these new reporting requirements, the AER should consider the additional burden placed on distributors under the Scheme. Much of the data identified in Table 10 of the Consultation paper (particularly the pre-project data) is already provided by distributors under existing reporting obligations. New reporting obligations, which require distributors to present already publically available information in a slightly different format, will unnecessarily increase costs to consumers. As noted in our response to question 2, while we recognise that there may be scope to improve the current reporting by distributors, it is essential that the scope and format of any additional reporting is carefully formulated to ensure that it is fit for purpose, and that data requests are targeted in such a way as to minimise the reporting burden.

In relation to post-project reporting and reviews, it is important to recognise that non-network demand management projects are, by their nature, often riskier than network solutions. If expenditure incurred on non-network demand management solutions is disallowed by the AER during the post-project review process, this is likely to discourage distributors from pursuing non-network demand management solutions.

1.4 INNOVATION ALLOWANCE MECHANISM DESIGN OPTIONS

Question 8: Which of the options discussed in section 7 would best achieve the Allowance Mechanism's objective? Please provide reasons supporting your view. If you prefer an Allowance Mechanism design that we did not discuss as an option in section 7, please provide details on this option.

Preferred option

In Jemena's view, the Allowance Mechanism design most likely to achieve the Allowance Mechanism objective is one which combines elements of Option 2 (high cap allowance with ex-ante approval) and Option 3 (bidding to encourage 'ground-breaking' R&D). Such a scheme would set a baseline allowance for distributors to pursue and deliver innovative projects, while also encouraging and enabling distributors and third parties to collaborate on breaking R&D projects. Part of the baseline allowance could be used by distributors to transpose the results of ground breaking R&D projects to their specific networks, thereby maximising the benefits to customers.

A high cap allowance scheme (Option 2), would overcome one of the key issues with the existing DMIA, which is that allowances are set too low. An ex-ante approval process does limit the risk to distributors of spending large sums of money that cannot be recovered. However, if distributors are required to propose innovative projects as part of their regulatory proposals, there is a risk that innovation will be stifled in later years of each regulatory control period. Given the pace of change in the energy sector, it is not possible to accurately predict what type of innovative projects might be pursued six to seven years in advance. This means that distributors will be less able to propose specific innovative R&D projects in their regulatory proposals. Even when projects can be identified, the detail to support such projects will be much less than those proposed for the early years of a regulatory control period. It is imperative that the Scheme recognises this issue, and that AER's assessment of innovation proposals is made within this context.

Question 9: If you have views against applying any of the particular mechanisms discussed in section 7 *(allowance mechanism design options)*, please provide reasons to support this view.

Option 1: Minor extension to the status quo

We do not support an Allowance Mechanism design which involves a minor extension to the current Demand Management Incentive Allowance (**DMIA**) under Part A (design Option 1). The DMIA is determined by reference to a distributors' revenue, and is therefore a function of the scale of the business. Many demand management trials have fixed costs which do not scale with network size. This means that smaller distribution businesses are disadvantaged when seeking to fund innovative demand management trials, particularly given that expenditure above the approved DMIA is subject to the workings of the EBSS and/or CESS. For example, in 2015 JEN engaged a consultant to look at deploying grid size batteries to address capacity constraints on 11/22kV distribution feeders. The minimum battery size determined by the consultant was 500kW/800kWh, at an estimated unit cost (at the time) of $1.5M (excluding project management and on-costs). As this was well beyond our DMIA of $1M over five-year period, we were unable to pursue this opportunity further. If the Allowance Mechanism is based on current DMIA allowances, smaller networks like JEN will continue to be disadvantaged, and will be less able to pursue any meaningful innovative demand management R&D.

Option 4: Bidding to encourage market-facilitated R&D

We strongly oppose this option, which would incentivise distributors to run a bidding process to award funding to third parties that propose innovative R&D projects, but preclude them participating in the identification and delivery of innovative R&D projects.

Distributors are well placed to come up with innovative *demand management projects that have the potential to reduce long term network costs*, or to work with third parties to identify and deliver innovative R&D projects consistent with demand management innovation allowance objective.[12] To reduce the role of distributors to little more than scheme administrators would appear contrary to the demand management innovation allowance objective. Surely, the best interests of customers' would be served by an Allowance Mechanism which encourages participation from as many parties as possible, including distributors.

Question 10: How we might best give effect to or enhance the information and reporting requirements discussed in section 7.5 *(proposed information and data requirements)*?

Jemena agrees that adequate documentation of projects is essential to fully realising the benefits of innovative R&D projects. We note that the information and data requirements proposed in the Consultation paper will require distributors to submit pre-project implementation plans to the AER. Under the current DMIA, distributors are not required to submit pre-project documents to the AER. As previously noted, it is important to recognise that this will be an additional requirement on businesses. To ensure that projects are delivered in a timely and efficient manner, it will be essential for the AER to ensure that its review of the pre-project implementation plans is timely and efficient. This will be best achieved by providing distributors with clear guidance on the information it requires, and the principles by which it intends to assess the innovative R&D demand management projects. The AER might also provide distributors with examples of what it considers to be 'best-practice', so that expectations are clearly articulated and understood.

[12] National Electricity Rules (**NER**), Part 6.6.3A(b)