Demand Management Incentive Scheme and Innovation Allowance

Response to AER Consultation Paper

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Energy Networks Australia

Contents

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Overview

Energy Networks Australia welcomes this opportunity to respond to the Australian Energy Regulator's (AER's) Consultation Paper *Demand management incentive scheme and innovation allowance mechanism* published on 4 January 2017.

Energy Networks Australia is the national industry association representing the businesses operating Australia's electricity transmission and distribution, and gas distribution networks. Member businesses provide energy to virtually every household and business in Australia.

This consultation is occurring at a time of significant technological and market change in the energy sector. In this context of an industry that is under transformation, we support the development of an effective Demand Management Incentive Scheme (DMIS) and Demand Management Incentive Allowance (DMIA) by the AER. These mechanisms will play a crucial role in preparing networks and the market for the future where non-network options will become increasingly important as new technology and better affordability make them suitable substitutes for network solutions.

In this submission, Energy Networks Australia proposes a number of suggestions to strengthen the incentives for distribution network service providers (DNSPs) to undertake demand management projects that deliver a net benefit to consumers.

Energy Networks Australia also draws the AER's attention to the existing incentives in the broader regulatory framework that already encourage DNSPs to pursue the most cost efficient solution. In this context, we consider that any pre-emptive calls on best delivery mechanisms embedded in the DMIS design could increase potential costs for customers. Energy Networks Australia notes that networks are delivering insourced demand management services today.

Design of the Incentives Scheme

Application of the new rule

The objective of the DMIS is to incentivise the implementation of <u>**efficient**</u> non-network options to manage demand. To achieve this outcome, the DMIS must promote an efficient level of demand management in the mix of inputs that DNSPs use to deliver services. This will lead to lower overall system costs and ensure the benefits to customers of the shared network.

The DMIS must not create a bias toward supporting inefficient network service delivery models to promote a goal of fostering or facilitating competition. Where a non-network option relating to demand management represents the most efficient solution to address the identified need, it should be procured as efficiently as possible, whether it is provided by the DNSPs in house, or by a third party through a competitive tender. In its final determination, the Australian Energy Market Commission (AEMC) stated:

> *As noted, distribution businesses will always need to be the decision makers with regard to whether a network or non-network option provides the most efficient solution to address a constraint on their networks. The question of who is best placed to provide possible non-network solutions is a separate question.* ***The frameworks in the rules encourage distribution businesses to identify and pursue the most efficient (or least cost) solution, irrespective of whether that solution is a network or non-network option or, in the case of the latter, whether it is provided by the distribution business in house, or by a third party through a competitive tender.***[1]

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.

Energy Networks Australia considers that the scope of eligible projects should be interpreted as broadly as possible. We are concerned that the AER's interpretation of the definitions may prohibit DNSPs delivering a range of demand management initiatives.

Under the new rule, expenditure under the scheme must be on efficient non-network options relating to demand management. The objective and principles for the DMIS are, therefore, closely linked to "network options" versus "non-network options". The interpretation of this link by the AER is not free from doubt. The AEMC's final determination contains explanatory material that suggests it anticipated a broader scope of the new rule than that in the AER's interpretation. The following

[1] AEMC, Rule Determination, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015, August 2015, p.21.

considerations support this broader view of eligibility:

- The scheme must incentivise efficient expenditure on non-network options that are 'related to demand management'. Therefore, demand management solutions should not be artificially excluded because they involve different *means* of reaching the targeted ends.[2]
- The AEMC indicated that expenditure on embedded generation to avoid funded augmentations can fall within the scope of 'non-network options related to demand management'.[3]
- The AEMC recognised that a demand management solution may involve network ownership and expenditure on distribution assets, load control of residential appliances being an example.[4]

It appears that the current interpretation in the Consultation Paper is not yet aligned with the policy intent reflected in the AEMC's final determination.

Incentive for demand management within current regulatory framework

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.

The current inability of DNSPs to internalise the net market benefits of demand management projects reduces their competitiveness with network solutions. This was a critical factor according to the AEMC and a driver for the amendments made to the *National Electricity Rules* (NER). Therefore, the key focus should be on addressing the specific market failure that has limited DNSPs' ability to implement demand management alternatives. The COAG Energy Council described it as follows:

> *The current inability of DNSPs to secure a fair proportion of all benefits created by their demand management projects across the supply chain amounts to a market failure, which is likely leading to inefficient under provision of such projects.*[5]

An incentive scheme that enables DNSPs to earn an appropriate financial reward and share in the broader market benefits resulting from their demand management activities will encourage the uptake of efficient non-network options relating to

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[2] AEMC, Rule Determination, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015, August 2015, p.60.
[3] ibid, p.60.
[4] Ibid, p.57 and p.60.
[5] COAG Energy Council, Rule change request, Reform of the Demand Management and Embedded Generation Connection Incentive Scheme, December 2013, p.5.

demand management. The effect will be an increase in the competitiveness of non-network solutions by justifying projects that are not cost effective to an individual DNSP, but cost effective to the National Electricity Market as a whole.

It is important to note that markets for demand management service providers are still developing. Markets are likely to develop to a greater degree in response to the opportunities created by the DMIS. The AER intends to encourage this process by implementing mechanisms, which enhance competition and information disclosure.

Energy Networks Australia considers that any pre-emptive calls on best delivery mechanisms embedded in the DMIS design would detract from the achievement of the DMIS objective. To ensure the demand management can be procured as efficiently as possible, it is important to allow competition between both insourcing and various outsourcing delivery options. The existing incentives in the broader regulatory framework already encourage DNSPs to pursue the most cost efficient solution.

Energy Networks Australia agrees with the AER's assessment that better pricing signals will promote demand management, however, this will take time to achieve. Once more cost-reflective tariffs are in place, it is expected that the need for specific demand management incentives will be reduced. Currently, recognised barriers cost-reflective pricing include metering penetration, jurisdictional policies and a reliance on "opt in" frameworks.

In the meantime, the DMIS will play a crucial role in preparing networks and the market for the future where non-network options will become increasingly important as new technology and better affordability make them suitable substitutes for network solutions.

Potential scheme design options

The AER's Consultation Paper identifies a range of mechanisms that could be included in the design of the scheme:

1. Targeted mechanisms to address specific perceived disincentives.
2. A net-market benefit sharing mechanism.
3. Mechanisms to promote the involvement of third party demand management providers to undertake demand management.
4. Demand management targets.

Energy Networks Australia considers the first two options would be likely to contribute to the achievement of the DMIS objective without compromising efficient outcomes to customers. These options provide a direct incentive to DNSPs to undertake demand management projects, and to address factors that have limited DNSPs' ability to implement demand management alternatives. To be effective, the DMIS will require a number of mechanisms that form part of the AER's options 1 and 2 to work in combination to address multiple issues.

Mechanisms to target potential disincentives

This option is important to achieving the DMIS objective. DNSPs are unlikely to invest in demand management where penalties or disincentives exist.

The DMIS should work in harmony with other parts of the regulatory framework, particularly the Regulatory Investment Test for Distribution (RIT-D), Service Target Performance Incentive Scheme (STPIS), Capital Expenditure Sharing Scheme (CESS) and the Efficiency Benefit Sharing Scheme (EBSS). Unintended interactions with these mechanisms may undermine the operation of the DMIS and the DMIA. For example, we would support the continuation of exclusion of the DMIA expenditure from the opex building block and the EBSS.

We also note the DMIS needs to incentivise networks to implement efficient demand management over the long term and not just the forthcoming regulatory period.

Net-market benefit sharing

> **Question 3**
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> Do you see value in exploring the net-market benefit sharing mechanism 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?

This option is worth consideration, as it would address a key issue with the previous framework identified by the AEMC. One possible approach to implementation of this mechanism could include:

- a $X per kVA incentive to reflect a share of upstream net market benefits from demand management. The average cost of extra capacity can be used as a concept to explain the benefits, similarly to how it would be used in RIT-D evaluations.
- kVA and benefit calculation methods to be the same as those used for RIT-D evaluations.
- The DMIS incentives to be included in the “? -factor” in the year following a secured commitment to reduce demand.

We recognise the AER’s concerns that valuing up-stream benefits can be complex. Energy Networks Australia would be open to recognising these values through an estimated broad benefit recovery rate incentive, to be applied to all employed demand management solutions or through the proposed ‘opex uplift’. Even though Energy Networks Australia would be open to such an approach, it is recognised that this would only apply in locations with a network constraint.[6] Otherwise system costs for all customers would increase inefficiently. As per the Network Capability Improvement Incentive Scheme example noted by the AER, for every $1 spent on demand management solutions DNSPs could receive $1.50 in incentives.

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 (that is, under a net market benefit sharing mechanism)?

Energy Networks Australia considers that RIT–D assessed projects should not be treated differently under the proposed DMIS. The existing RIT-D requires DNSPs to consider broader market benefits but this does not equate to a DNSP being able to secure a share of the value of those benefits. For example, if the option to address an identified network need is being assessed under the RIT-D and requires $10 million in capital expenditure, then the presence of additional market benefits from this option will not affect that $10 million. However, it might place this option ahead of an alternative option that does not create market benefits.

If the option duly passes the RIT-D and is then included in a DNSP's regulatory proposal, the AER would only allow $10 million to be recovered. The DNSP is not recovering any additional financial benefit from having put forward a project with these broader market benefits.

It is Energy Network Australia's understanding that the proposed DMIS should instead enable DNSPs a mechanism to attain a financial share of these benefits. Therefore, there should be no need to change the current RIT-D, nor are there any regulatory conflicts with the potential introduction of a DMIS.

Mechanisms to promote competition

For the reasons outlined earlier in this submission, Energy Networks Australia considers that options such as the bidding mechanism to encourage market delivery risks detracting from the achievement of the DMIS objective.

We note that stakeholders raised a number of issues concerning the interaction of DNSPs with contestable markets. These issues are currently under consideration as part of *Contestability of energy services* rule change.

Members of Energy Networks Australia support transparency of information on network constraints, and how they may be overcome. Our preference is that such information is provided through collaborative 'open source' solutions such as the Institute for Sustainable Futures' Networks Opportunity Maps. DNSPs have been working with academic institutions and other stakeholders to provide information via Networks Opportunity Maps that may be used by proponents of non-network

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[6] AEMC, Rule Determination, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015, August 2015, p.60.

alternatives to develop a common understanding of the potential value of reducing peak electricity demand in different parts of the network.

It is important to recognise the existing and proposed mechanisms that provide information to market participants who may be able to offer non-network solutions. These include:

- DNSPs currently report on demand management projects in their Distribution Annual Planning Reports (DAPRs), including the non-network options considered in the past year, the actions taken to promote non-network proposals in the past year and their plans for demand management over the forward planning period.
- The 'system limitations report' proposed by the Australian Energy Market Commission as part of local generation network credits rule change, if implemented, would provide additional information.
- New reporting requirements are likely to stem from of the *Replacement expenditure planning arrangements* rule change process.

Demand management targets

This option is unlikely to promote efficient outcomes and is inconsistent with the goal of providing customers with efficient, value for money solutions in a dynamic technology environment. The key concern with the setting of such targets is that they would be based on a DNSP's requirements at a particular point in time. This ignores the fact that network planning is a continuous process. Though network investment may be forecast a number of years into the future, there can be deviations in such forecasts as a result of changes in customer demand or other new information. This can lead to a material variation or even the entire removal of a previously identified investment need. Overall, Energy Networks Australia considers that other measures would be preferable to targets for demand management deployment.

Question 5

How might we best combine the mechanisms discussed in section 6 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.

As above.

Regulators in some international jurisdictions use incentives for utilities as interim measures to consider non-network options to provide optionality or deferral of another solution. An example of this type of project is the Brooklyn Queens Demand Management (BQDM) program. The New York Public Service Commission (NY PSC) has adopted the totex approach in the limited context of new expenditures in the BQDM project. The NY PSC authorised a return on the totex of the project, which proposes non-traditional alternatives to address an overloaded sub-transmission feeder. This represents an early experiment in developing new business models, rather than a preferred approach.[7]

Information box - Brooklyn Queens Demand Management project[8]

A "ground-breaking" non-wires-alternative, yet includes transitional incentives and falls short of the DSP third-party vision.

Involves 52 MW of non-traditional utility-side and customer-side solutions and traditional utility infrastructure investment, including 6 MW of capacitor bank installations and 11 MW of load transfers.

Consolidated Edison defers $1.2B Capex for two substations and with DG, DM and EE which receive a return on totex and performance incentives.

It uses a totex-style approach to amortising all BQDM program costs over a 10-year period, with an ROR adder increasing the returns to capital.

Question 6

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

As above.

[7] ibid, p.16.
[8] ibid, p.91.

Design of the Allowance Mechanism

There was clear recognition during the rule change process that more needs to be done to promote innovation. To date, there has not been sufficient recognition of the importance of encouraging innovation in traditional network economic regulatory approaches.

With the transformational trends affecting energy networks arising due to rapidly evolving technologies and business models, innovation in the delivery of network services may have a much larger societal benefit, and its absence a higher cost, than has been the case historically. The DMIA can play an important role in positioning networks well to achieve optimal outcomes by investing in, exploring, trialling and deploying the right technology at the right time.

> Question 8
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> Which of the options discussed above 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.

Energy Networks Australia would support the DMIA mechanism, which allows DNSPs to seek a higher allowance in addition to the existing DMIA. This could entail the adoption of option 2 or a combination of options 1 and 2.

The DMIA level of funding must be sustainable, long-term and predictable so that DNSPs can plan and execute multi-year (and multi-regulatory period) innovation projects. We agree with the AER that the DMIA should provide for *ex-ante* rather than *ex-post* funding approvals. Funding could be recovered from each business's electricity network customers, however, how to best recover it will require consideration. Our initial view is that it may be beneficial for the DMIA to have the following features:

» include high-cap allowances to ensure that long term, ambitious projects can be taken forward. DNSPs may not utilise all available funding.

» adopt "Use it or lose it".

» adopt a broad interpretation of innovation. It is important that DNSPs are able to test new technologies and solutions in their own network circumstances to ensure a benefit can be derived with no adverse impacts to the safety and reliability of the network.

» include scope for DNSPs to change aspects of projects after funding has been awarded to recognise evolution in markets and technologies. This would facilitate cost-effective exploration of demand management innovations in a timely manner, and ensure potential efficiency.

» allow non-network parties that wish to partner with networks. This is to recognise the importance of collaboration and leverage the knowledge and experience of other parties, where possible.

Question 9
If you have views against applying any of the particular mechanisms discussed in section 7, please provide reasons to support this view.

Energy Networks Australia is concerned with options that exclude DNSPs from implementing solutions, such as under the AER's option 3. Such an approach is unlikely to achieve the objectives of the DMIA because network firms' experience is crucial to achieving successful innovation and applying it in business as usual processes.

Energy Networks Australia is broadly supportive of the approach to innovation adopted by Ofgem in the UK. Under Ofgem's Innovation Stimulus Package, there is an annual opportunity for electricity network companies to compete for funding for the development and demonstration of new technologies, operating and commercial arrangements. Funding is then provided for the best innovation projects that offer cost savings and/or wider environmental benefits for customers.[9]

We note that the DMIA is specifically targeted to demand management activities and does not include all types of innovation. From a practical perspective, the administrative burden of running and participating in network competitions can be quite high. If this option was chosen, it would be important to ensure that the benefits are not too small when compared to implementation costs. For example, the AER could rely on approaches that reduce the regulatory and administrative burden.

Information box – Costs of Ofgem's policies for innovation

Ofgem provided up to £500 million over a 2010-15 period to support innovative projects on electricity distribution networks that would contribute to the development of a low carbon economy[10]. Ofgem approved approximately £250 million of funding to Distribution Network Operators (DNO) over 2010-2015.

To put it in context, in 2010, the network industry in the UK was valued at £43 billion.[11]

Network Innovation Competitions - Electricity transmission	8 years April 2013 – March 2021	£240 million[12]
Network Innovation Competitions - Gas distribution and gas transmission	8 years April 2013 – March 2021	£160 million

[9] Ofgem, https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition, accessed on 24 February 2017.
[10] Ofgem, https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund, accessed on 24 February 2017.
[11] Ofgem, RIIO - a new way to regulate energy networks, Factsheet 93, October 2010, p.1.
[12] Ofgem, Policies right for innovation, 4th Annual Smart Grids & Cleanpower 2012 Conference, July 2012, p.15.

Low Carbon Networks Fund - Electricity distribution	5 years April 2010 – March 2015	£500 million
		£900 million

Network Transformation Roadmap

In the medium term (2017-2027), an integrated innovation scheme may be required as a stimulus for addressing a range of concerns about the incentives for innovation and a lack of sufficient network innovation funding and programs. This is to ensure that all types of network innovations are promoted. The Electricity Network Transformation Roadmap identifies innovations for distribution networks in a number of areas:

- Innovation with customer engagement through customised choices, better information on services, and developing universal energy authorisations/exemptions and customer protections frameworks.[13]
- Innovation in pricing and regulatory incentives through faster transition to cost reflective tariffs and new prices for differentiated services, enabling more choice for customers either offering their distributed energy resource output to networks or to other market participants.[14]
- Innovation in regulatory arrangements through new, more adaptive regulatory frameworks that are customer-focused, removal of barriers for microgrid and standalone power systems where they are more cost effective and new incentives for innovation in regulatory outcomes.[15]
- Innovation in system operation and management and information exchange through the development of open standards and protocols and enablement on interoperability with distributed energy resources.[16]

Information and reporting requirements

Question 10

How we might best give effect to or enhance the information and reporting requirements discussed in section 7.5?

The AER should adopt reporting requirements that are proportionate to the allowance that is recovered. For example, high cap projects may require a certain level of additional oversight and transparency when compared to the current arrangements.

It is important to strike an appropriate balance to ensure the proper level of oversight

[13] Refer Roadmap Chapters 1 and 2 milestones for customer oriented networks and customer safety net
[14] Refer Roadmap Chapter 7 Pricing and Incentive Milestones
[15] Refer Roadmap Chapter 8 Regulatory and Policy Frameworks
[16] Refer Roadmap Chapter 10 Grid Transformation Milestones

and avoid any barriers that may discourage DNSPs and project partner involvement. With respect to project approval criteria discussed by the AER in Section 7.5 of the consultation paper, Energy Networks Australia notes that:

- the complexity of application preparation may itself represent a barrier, unless carefully designed.
- the precise cost/benefit of a project may be difficult to determine on an *ex ante* basis due to the uncertainty around its innovative nature (by definition, dynamic innovation is different to incremental projects assessed on a narrowly defined net present value basis).
- guidance could be given by the AER on acceptable assumptions with respect to costs, acceptable mitigations throughout the project and expected financial benefits due to the uncertainty of the future.
- It is important that the AER provides clarity around the process for requesting project changes project/additional funding.