RULE

Australian Energy Market Commission

CONSULTATION PAPER

NATIONAL ELECTRICITY AMENDMENT (DEMAND MANAGEMENT INCENTIVE SCHEME AND INNOVATION ALLOWANCE FOR TNSPS) RULE

PROPONENT

Energy Networks Australia

23 MAY 2019

INQUIRIES

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E aemc@aemc.gov.au
T (02) 8296 7800
F (02) 8296 7899

Reference: ERC0266

CITATION

AEMC, Demand management incentive scheme and innovation allowance for TNSPs, Consultation paper, 23 May 2019

ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

CONTENTS

TABLES

FIGURES

1 INTRODUCTION

On 1 March 2019, Energy Networks Australia (ENA) submitted a rule change request seeking to amend Chapter 6A of the National Electricity Rules (NER) by requiring the Australian Energy Regulator (AER) to develop a Demand Management Incentive Scheme (DMIS) and a Demand Management Innovation Allowance (DMIA), similar to the DMIS and DMIA already in place for distribution network service providers (DNSPs), to apply to transmission network service providers (TNSPs).[1]

Under the current rules, the DMIS and DMIA are only available for DNSPs. The Commission made the *Demand management incentive scheme* rule in 2015.[2] ENA proposes to apply the same approach to transmission, including giving the AER discretion as to whether to apply the schemes and in determining incentive powers.

This paper has been prepared to facilitate public consultation on the rule change request and to seek stakeholder submissions. It outlines:

- Details of the rule change request (Chapter 2)
- The Commission's assessment framework (Chapter 3)
- Issues for consultation (Chapter 4)

Information on how to lodge a submission on this consultation paper is provided in Chapter 5. Submissions are due by **Thursday 11 July 2019**. The project timeline is shown below in Table 1.1.

Table 1.1: **Project timeline**

MILESTONE	DATE
Submissions to consultation paper close	11 July 2019
Draft determination and draft rule published	19 September 2019
Submissions to draft determination close	31 October 2019
Final determination and final rule published	12 December 2019

Appendix A provides a high-level overview of:

- The role and benefits of demand management
- Demand management research and development (R&D) in networks
- How the DMIS and DMIA apply to distribution
- Electricity network economic regulation under the current regulatory framework
- The Commission's consideration of incentive regulation through the *2019 Economic regulatory framework review*

1 ENA, *Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request*, February 2019.

2 AEMC, *Demand management incentive scheme, Rule Determination*, August 2015.

For further background information on the regulatory framework, including the current DMIS and DMIA for distribution, stakeholders are encouraged to read ENA's rule change request document, which is available here: https://www.aemc.gov.au/rule-changes/demand-management-incentives-tnsps

2 DETAILS OF THE RULE CHANGE REQUEST

ENA proposes amendments to Chapter 6A of the NER to require the AER to develop a DMIS and DMIA to apply to TNSPs.

In its rule change request, ENA identifies potential shortcomings of the current regulatory framework and explains how its rule change request addresses these issues. ENA's proposed amendments to the rules mirror those that were introduced for distribution (Chapter 6 of the NER) in 2015.

2.1 Issues raised by the rule change request

ENA submits that the key driver for the proposed introduction of a DMIS for TNSPs is the current lack of positive financial incentives for the adoption of potentially lower cost non-network operating expenditure solutions:[3]

> TNSPs are an active participant in the market for non-network services and seek to contract directly for demand management support (rather than contracting through DNSPs) to manage issues on the transmission networks.
>
> Energy Networks Australia members have consistently observed that the current transmission regulatory framework provides no positive financial incentive for TNSPs to pursue and procure non-network solutions, notwithstanding the associated reputational and compliance risks associated with putting in place a non-network solution, particularly when the market for non-network solutions is still developing. This lack of positive incentive creates an imbalance of incentives as between non-network solutions and network solutions which do not face these practical hurdles.

ENA states that a key difference in the regulatory framework applying to TNSPs compared to DNSPs is that TNSPs have a network support pass through codified as part of the NER.[4] ENA considers this cost pass through arrangement assists TNSPs to manage risks associated with network support payments that are outside of their control, and so will remain required to support the efficient adoption of non-network options in transmission. However, ENA says it is not sufficient by itself since it does not provide a positive incentive to adopt efficient non-network solutions.[5]

Further, ENA states the current regulatory framework provides a disincentive to incur expenditure on research and development (R&D) into new and more innovative techniques for utilising non-network technologies:[6]

> This is because any expenditure on R&D results in an immediate increase in opex (and therefore has the effect of reducing EBSS amounts), which are not offset by a decrease

3 ENA, *Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request*, February 2019, p. 8.

4 ibid, p. 10.

5 ibid, p. 4.

6 ibid, p. 13.

> in either opex or capex in the same regulatory period (which would provide an offsetting increase in either EBSS or CESS amounts).

ENA submits that the current regulatory framework does not provide certainty that any expenditure on R&D to further develop efficient long-term non-network solutions will be able to be recovered by the TNSP. ENA says:[7]

- although the network capability incentive parameter action plan component of the Service Target Performance Incentive Scheme (STPIS) has previously been used by TNSPs to fund innovation trials, including in relation to the operation of grid-scale batteries, these projects are expressly required to relate to improving a TNSP's 'network capability'
- it is unlikely the expenditure on innovation that is expected to result in cost reductions in future regulatory periods (rather than the current period) would be accepted by the AER as part of a TNSP's operating expenditure allowance.

ENA says TNSPs have limited scope to influence end-customer behaviour through tariffs (to manage network constraints), and that currently the tariffs faced by customers are primarily directed at addressing challenges faced by distribution networks:[8]

> Transmission costs are an input to the tariffs set by DNSPs, but the structure and level of transmission tariffs are generally not passed through to consumers, particularly at the household and small business level.

2.2 Proposed solution

To address the above issues under the current regulatory framework, ENA considers the introduction of:[9]

- the DMIS would provide TNSPs with a financial incentive to implement efficient non-network options, which are expected to lower costs to consumers
- the DMIA would provide TNSPs with funding to research and develop innovative non-network arrangements in connection with the operation of their transmission networks, with the prospect of lowering costs to consumers in the longer term.

ENA submits non-network arrangements can reduce the overall long term costs of supplying electricity to customers, and that with the emergence of new technologies and a more stable peak demand outlook at a transmission level, the importance of non-network options as enduring solutions will continue to grow.[10]

ENA says efficient development and delivery of non-network initiatives, supported by more balanced incentives on transmission businesses, will ensure that the market for non-network

7 ibid, p. 14.
8 ibid, p. 12.
9 ibid, p. 6.
10 ibid, p. 18.

support deepens and will enable transmission services to be provided at the lowest efficient cost to consumers.[11]

ENA acknowledges consumers would ultimately fund the allowances under the DMIS and DMIA. However, ENA says these costs are expected to be modest relative to the long term cost savings brought about by increased use of efficient non-network options arising as a consequence of both the scheme and innovation allowance, and gains may also be immediately available to individual consumers where they offer or become involved in demand management projects (such as direct load control). ENA also notes that payments under the DMIS and DMIA mechanisms developed by the AER for distribution are capped.[12]

ENA proposes giving the AER discretion in deciding whether to apply the DMIS and DMIA, and would allow the incentives/allowance under the schemes to vary by TNSP and over time. ENA notes that the DMIS and DMIA for distribution include a substantial oversight role for the AER in approving payments under the two mechanisms, ensuring that customers benefit from the application of the schemes.[13]

ENA recognises the potential regulatory developments being considered by the Commission as part of the Economic regulatory framework review, saying the AER's application of the DMIS/DMIA could evolve over time to take account of any broader developments in the regulatory framework.[14]

The proposed rule change is consistent with the DMIS and DMIA that have already been developed and implemented for distribution network regulation. ENA submits the administrative costs of extending these schemes to TNSPs are therefore expected to be minimal.[15]

ENA proposes to allow TNSPs to apply to the AER for early application of the DMIS during the current regulatory control period – the AER could then apply the DMIA at the time of the next regulatory determination for each TNSP.[16]

11 ibid, p. 18.
12 ibid, p. 20.
13 ibid, pp. 6–7.
14 ibid, p. 6.
15 ibid, p. 22.
16 ibid, p. 13.

2.3 Proposed rule drafting

ENA proposes to amend existing clauses and include new clauses under Chapter 6A of the NER, as well as amending clauses under Chapter 11 (Savings and transition),[17] as follows:

- Chapter 6A (economic regulation of transmission services) would be amended to add in the relevant objectives and principles for the DMIS and DMIA, consistent with the objective and principles set out in 6.6.3 and 6.6.3A of Chapter 6 (economic regulation of distribution services).
  - Consequent amendments would also be required to 6A.5.4(a)(5) and 6A.5.4(b)(5), which relate to a description of the building blocks.
- Either Part ZZZH of Chapter 11 (Savings and transition) would be amended, or a new Part added to Chapter 11 to allow TNSPs to apply to the AER for early application of the DMIS, ahead of their next regulatory determination, consistent with the rules contained in the National Electricity Amendment (implementation of demand management incentive scheme) Rule 2018 No.3.

17 ibid, p. 23.

3 ASSESSMENT FRAMEWORK

3.1 Achieving the NEO

Under the National Electricity Law (NEL) the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[18] This is the decision making framework that the Commission must apply.

The NEO is:[19]

> To promote efficient investment in, and efficient operation and use of, electricity services for the longer term interests of consumers of electricity with respect to -
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Based on a preliminary assessment of this rule change request, the Commission considers that the relevant aspects of the NEO is the efficient investment in, and efficient operation and use of, electricity services for the longer term interests of consumers of electricity with respect to the price.

3.2 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

3.3 Making a differential rule

Under the Northern Territory legislation adopting the NEL, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a different rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. A differential rule is a rule that:

- varies in its term as between:
  - the national electricity system, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

18 See NEL Section 88.

19 See NEL Section 7.

As the proposed rule relates to parts of the NER that currently do not apply in the Northern Territory, the Commission does not consider that the proposed rule will need to be assessed against additional elements required by the Northern Territory legislation.[20]

20 From 1 July 2016, the NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the NEL. Under those regulations, only certain parts of the NER have been adopted in the Northern Territory. (See the AEMC website for the NER that applies in the Northern Territory.) National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.

4 ISSUES FOR CONSULTATION

Issues for consultation relevant to ENA's rule change request are discussed below to provide guidance for stakeholder submissions.

Stakeholders are encouraged to broadly comment on these issues, as well as any other aspect of the rule change request.

4.1 Benefits of promoting demand management

ENA's proposal would promote innovation and create financial incentives for TNSPs to undertake demand management approaches.

Electricity network demand management helps to remove, reduce or defer network constraints, which potentially provides a less costly alternative to network investment (Appendix A.1). R&D in demand management projects could increase a TNSP's ability to undertake non-network solutions (Appendix A.2). Examples of non-network solutions may include local generation, co-generation, demand-side response and services from a market network service provider. Lower total system costs mean lower electricity prices for consumers, all other things being equal.

Although it is generally acknowledged the market for non-network service providers at the transmission level is in its relative infancy, third party providers are expected to innovate and grow especially as technology develops – which would lead to further opportunities. For example, in the future, TNSPs may procure services provided by 'aggregators' of distributed energy resources to help the networks reduce peak load to defer network augmentation, or to help manage the technical characteristics of their networks. Also, TNSPs currently have limited scope to influence end-consumer behaviour through cost reflective tariffs, but price signals could become more of a factor in the future to efficiently manage network constraints.

Consumers would ultimately fund the allowances under the DMIS and DMIA. These payments increase total allowed revenue, which in turn means higher network charges for consumers in the short term. ENA considers that these costs would be outweighed by longer-term cost savings for consumers as a result of more efficient expenditure.[21]

The Commission will consider whether the future benefits of introducing a transmission DMIS and DMIA are likely to outweigh the upfront costs.

For distribution, the Commission previously found that the future benefits of the DMIS and DMIA are likely to outweigh the upfront costs (Appendix A.3). Given these schemes were only recently introduced, the extent of the benefits to consumers are still being tested for distribution. The Commission welcomes feedback from stakeholders on whether the DMIS and DMIA for distribution have been effective so far, including examples.

21 ENA, *Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request*, February 2019, pp. 20–22.

QUESTION 1: NON-NETWORK OPTIONS FOR TNSPS

The Commission seeks stakeholder views on the following:

- Are non-network options for transmission readily available? Or is the rule change proposal addressing a future or emerging issue?
- Are the benefits (potential payoffs) and viability of non-network solutions inherently different for distribution networks compared to transmission networks?
- Does the application of the DMIS and DMIA for DNSPs provide any relevant evidence as to the potential benefits of increased network demand management?

In relation to the proposed DMIA for TNSPs, the Commission is also interested in stakeholder views on whether R&D by TNSPs into new and more innovative techniques for utilising non-network technologies have the potential to lead to significant benefits to consumers.

QUESTION 2: DEMAND MANAGEMENT R&D FOR TNSPS

- What are examples of past innovations by network businesses in demand management?
- What are examples of future demand management R&D that TNSPs may undertake and what are their potential payoffs?

4.2 Incentives for transmission demand management

The proposed introduction of a DMIS for TNSPs is based on the concern by ENA that there is a current lack of positive financial incentives for TNSPs to adopt potentially lower cost non-network operating expenditure solutions. Further, ENA says there are ‘practical hurdles’ associated with putting in place a non-network solution – such as reputational and compliance risks, particularly when the market for non-network solutions is still developing.[22] ENA considers that this potentially creates unbalanced incentives and a bias towards network capital investment under the current rules.[23]

This raises the question of whether there is an 'incentive gap' problem in the current regulatory framework that may discourage TNSPs from pursuing demand management projects as an efficient alternative to network investment.

The current rules require TNSPs to adopt least cost network solutions. The AER’s allowed revenue determinations are based on forecasts of efficient capital and operating expenditure. The Regulatory Investment Test for Transmission (RIT-T), which applies to all major investment decisions, is designed to explicitly consider non-network options and deliver the most efficient solution – regardless of both technology and ownership. Information

22 ibid, pp. 8–10.

23 ibid, p. 30.

asymmetries make it difficult for the AER to accurately assess the efficiency of the network businesses' proposals in practice.

To promote efficient investment decisions, the regulatory framework for TNSPs currently includes incentive mechanisms, such as the Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) and Service Target Performance Incentive Scheme (STPIS). These schemes provide network businesses with a continuous incentive to improve their efficiency in supplying electricity services – while maintaining or improving service standards (Appendix A.4).

In determining the prudency or efficiency of capital expenditure, the AER must have regard to whether the relevant project was evaluated against, and satisfied, the Regulatory Investment Test for Distribution (RIT-D) or the RIT-T, as the case may be.[24]

The purpose of the RIT-T is to identify the transmission investment option that maximises net economic benefits and, where applicable, meets the relevant jurisdictional or electricity rule based reliability standards. Under the NER, in applying the RIT-T, a TNSP must consider all options that could reasonably be classified as 'credible options', including non-network solutions.

A TNSP must apply the RIT-T to all proposed transmission investment except where a proposed investment is required to address an urgent and unforeseen network issue, or the estimated capital cost of the most expensive option to address the identified need is which is technically and economically feasible is less than $5 million – among other factors.[25] Where a TNSP does not need to apply the RIT-T to a proposed investment, a TNSP must ensure, acting reasonably, that the investment is planned and developed at least cost over the life of the investment.[26]

To help TNSPs manage risk that is outside of their control, the NER include provisions for network support cost pass through.[27] Network support payments are made by TNSPs to network support providers for services to manage anticipated network constraints. The pass through mechanism in the NER has been incorporated into the revenue cap framework to allow for some cost increases (or decreases) to be passed directly onto customers, where the cost increases (or decreases) are beyond the control of the TNSPs[28] – such as weather conditions, demand levels and electricity usage patterns. These pass through arrangements are intended to avoid TNSPs being financially penalised as a result of increased expenditure on demand management during a regulatory period, but ENA considers that they do not provide a positive financial incentive on TNSPs to undertake efficient levels of demand management.[29]

24 See NER clause S6A.2.2(3).
25 See NER clause 5.16.3(a).
26 See NER clause 5.16.3(d).
27 See NER clause 6A.7.2.
28 AER, *Procedural guideline for preparing a transmission network support pass through application*, June 2011, p. 1.
29 ENA, *Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request,* February 2019, p. 12.

QUESTION 3: OVERLAP WITH EXISTING INCENTIVE MECHANISMS

The Commission seeks stakeholder views on whether a DMIS and DMIA for transmission would complement or overlap with the above incentive mechanisms. For example:

- What, if anything, prevents the RIT-T from delivering a non-network solution where it is the most efficient solution?
- If a DMIS for TNSPs is introduced, would it materially overlap with or be inconsistent with the current incentive mechanisms such as the EBSS, CESS, STPIS and cost past through mechanism?
- If the cost past through mechanism is retained as proposed by ENA, how would a DMIS for TNSPs need to be structured to provide efficient incentives for demand management?
- To what extent should consumers bear the risk of short-term cost increases if TNSPs face higher incentives/rewards for increased demand management expenditure through a DMIS?

QUESTION 4: ALTERNATIVE APPROACHES

If there is an 'incentive gap' problem, the Commission is interested in stakeholder views on whether the ENA's rule change proposal is the most effective solution to this issue.

- Are there alternative approaches that would better achieve the objective of the ENA's rule change proposal?
- The Commission is considering this rule change request in parallel to its *2019 Economic regulatory framework review* (Appendix A.5). Would the DMIS and DMIA for transmission complement the Commission's broader consideration of potential alternative approaches to expenditure assessment and remuneration to address the potential for expenditure bias?

4.3 Implementation

Rather than prescribe in the NER that the AER must implement the DMIS and DMIA for each TNSP, ENA proposes to provide the AER with significant discretion in deciding whether to apply the DMIS and DMIA, and the rule change would allow the incentives/allowance under these schemes to vary by TNSP and over time.[30] Giving the AER discretion to apply the DMIS and DMIA could improve the flexibility and responsiveness of the regime to changing technologies and regulatory methodologies – especially if the benefits of the rule change are currently uncertain. This is consistent with the approach taken to the distribution DMIS and DMIA.

30 ibid, p. 6.

Under the proposed rule change, the DMIS (but not the DMIA) would apply immediately if a rule is made, with TNSPs able to submit applications to the AER seeking to have the DMIS apply part way through a current regulatory control period. In contrast, ENA proposes that the DMIA would not apply to a TNSP until the start of its next regulatory control period.[31]

This would mirror the approach for distribution DMIS that the Commission adopted as part of the rule change seeking early application of the DMIS.[32] At the time of that rule change, the AER had completed the development of the DMIS so that the Commission and other stakeholders understood how the DMIS for distribution would apply. The AER's design of the distribution DMIS involves a two-year lag between the accrual and payment of incentives such that the incentive payments will not be available to the TNSPs until the subsequent regulatory period.[33] This arrangement would therefore allow the application of the DMIS 24 months prior to the end of a TNSP's current regulatory period. The rule made by the Commission provided that a DNSP could not submit an application for the application of the DMIS more than two years prior to the end of its current regulatory control period.

As part of that rule change, application of the distribution DMIA during a regulatory control period was not proposed and was not supported by the AER as it was considered that it would require existing regulatory determinations to be reopened and amended, which would result in significant costs and complexity.

Those facts that applied to the Commission's decision on whether to allow the distribution DMIS to apply prior to the start of a regulatory control period may not necessarily apply to the proposed transmission DMIS. In particular, if made, the proposed rule would leave the AER considerable discretion regarding the detailed design of the transmission DMIS and there is no certainty that the AER would implement the same two-year lag between accrual and payment as it implemented for the distribution DMIS. This may make it more difficult to design a rule that allows for the DMIS to start to apply during a regulatory control period while being certain that this will not require the existing determination to be reopened and amended.

Potential solutions to this issue may be to permit the AER to decide whether to allow application within a regulatory control period, or to provide that the AER may only allow application within a regulatory control period if the AER is satisfied that doing so will not require the existing revenue determination to be amended.

BOX 1: STAGGERED REGULATORY CONTROL PERIODS FOR TNSPS

The timing of transmission network revenue determinations is currently staggered and the AER's decisions on TNSPs' revenue determinations are spread over three years. The AER's final decisions (covering five-year regulatory periods) for AusNet Services transmission and

31 ibid, p. 17.

32 See https://www.aemc.gov.au/rule-changes/implementation-of-demand-management-incentive-sche

33 ENA, *Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request,* February 2019, p. 13.

Powerlink were made in April 2017, while the TransGrid, ElectraNet and Murraylink determinations were finalised in April/May 2018. Most recently, the AER released its final decision for TasNetworks transmission in April 2019. The AER is currently consulting on Directlink's revenue proposal, with a final decision due by April 2020. This three-year spread of TNSP regulatory control periods is shown in Figure 4.1 below.

Figure 4.1: TNSP regulatory control periods

State/ Territory	Service Provider	Regulatory control period										
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
VIC	Ausnet Services					1 April 2022 - 30 March 2027						
QLD	Powerlink					1 July 2022 - 30 Jun 2027						
NSW	Transgrid						1 July 2023 - 30 June 2028					
SA	ElectraNet	1 July 2018 - 30 June 2023										
VIC/SA	Murraylink	1 July 2018 - 30 June 2023										
TAS	TasNetworks		1 July 2019 - 30 June 2024									
NSW/QLD	Directlink			1 July 2020 - 30 June 2025								

Source: Adapted from the AER's project timetable. See Source: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements

Under the ENA's proposal to allow the application of the DMIS from 24 months prior to the end of the regulatory control period, the staggered regulatory periods would mean that some TNSPs would be able to adopt the scheme earlier than others.

QUESTION 5: STAGED REGULATORY PERIODS AND THE APPLICATION OF DMIS

The Commission is interested in stakeholder views on the following issues:

- Is the ENA's proposed level of AER discretion regarding the design and application of the DMIS and DMIA appropriate?
- If a rule is made to adopt a DMIS for transmission, is there a way to design a scheme that would allow TNSPs to make applications for it to apply within a regulatory control period without the need to re-open the revenue determinations?
- How long after a final rule is made should the AER have to develop and consult on guidelines to implement the DMIS and DMIA?
- What other potential implementation or transitional issues should be considered by the Commission?

5 LODGING A SUBMISSION

Written submissions on the rule change request must be lodged with the Commission by **11 July 2019** online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0266.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions on rule change requests.[34] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Anthony Bell at anthony.bell@aemc.gov.au

34 This guideline is available on the Commission's website www.aemc.gov.au.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CESS	Capital Efficiency Sharing Scheme
COAG	Council of Australian Government
Commission	See AEMC
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution network service provider
EBSS	Efficiency Benefit Sharing Scheme
ENA	Energy Networks Australia
NEL	National Electricity Law
NEO	National electricity objective
NER	National electricity rules
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
R&D	Research and development
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission network service provider

APPENDIX A

A.1. How demand management can help to reduce total system costs

Electricity network demand management is the act of modifying the drivers of network demand to remove, reduce or defer a network constraint.

Demand management can reduce or shift peak demand and provide a less costly alternative to network investment. Network businesses may be able to shift or reduce net demand on the network through various methods, such as providing financial incentives to encourage behavioural change, contracting for local generation support or physically controlling electricity usage.[35]

Further, demand management can help to:

- address risks associated with equipment failure, defer the retirement or replacement of aging assets, or even offer smaller capacity replacement options
- manage high voltage levels and system frequencies, as well as power quality issues from needing to manage diverse power flows
- create flexibility to manage forecasting uncertainty.[36]

A.2. Demand management R&D in networks

R&D in demand management projects can reduce long term network costs, but increase expenditure in the short term. R&D could increase networks' capacity to explore, trial and deploy new technologies, systems and business processes in a timely manner[37] – which can create 'dynamic' efficiencies and deliver significant value to consumers.

Many of the innovative technologies and business models that enable effective demand management come from the contestable market.[38] However, network-initiated R&D may still be important. TNSPs are in a unique position to understand the challenges facing their networks and to formulate the research objective to address these challenges – even if the R&D itself is done in partnership with third parties.

R&D requires investment costs to be incurred by the network business and the 'payoff' is generally uncertain. Regulated monopolies, like network businesses, arguably have less of an incentive to conduct R&D than competitive businesses. This is because networks face lower 'up-side risk' given they cannot by definition gain a 'competitive advantage'. Moreover, to the extent that R&D results in future cost reductions, networks will pass a material portion of these gains onto electricity consumers through incentive regulation. Additionally, networks

35 AER, *Demand management incentive scheme: Explanatory statement*, December 2017, p. 11.

36 ibid, p. 12.

37 AER, *Demand management innovation allowance mechanism: Explanatory statement*, December 2017, p. 9.

38 ibid, p. 9.

still face 'down-side risk' – if R&D costs occur significantly before the benefits, the businesses risk being financially penalised from making these decisions under the EBSS and/or CESS.[39]

A.3. Demand management incentive framework for distribution

The AER is required under the NER to develop and publish the DMIS and DMIA schemes for distribution, consistent with the following respective objectives:

- provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management (DMIS)[40]
- provide distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs (DMIA).[41]

The AER published the DMIS and DMIA in December 2017 and has since begun applying the two schemes.

In 2015, the Commission made the *Demand management incentive scheme* rule in response to rule change requests submitted by the COAG Energy Council and the Total Environment Centre.[42] The Commission considered the final rule contributed to the achievement of the NEO by providing a framework to guide the AER in developing and applying a DMIS and DMIA to help balance the incentives on distribution businesses to make efficient expenditure decisions, which should lead to lower overall system costs and, in turn, lower retail prices for consumers.[43]

Pursuant to an AER rule change proposal, the Commission amended the NER in April 2018 to allow DNSPs to request that the DMIS be applied ahead of their next determination period.[44] As a result, DNSPs no longer have to delay the application of the DMIS until the commencement of their next regulatory control periods – which in some cases was two or three years away, at the time of the rule change.

As part of the *2015 demand management incentive scheme* rule change process, some stakeholders made submission on whether the DMIS and DMIA should also be applied to transmission. The Commission found:[45]

- TNSPs could, and had, contributed to effective demand management – albeit in a more limited capacity compared to the demand side and distribution side
- TNSPs were already required to consider the potential for demand management options (non-network options) under the RIT-T
- the AER could already provide funding for non-network solutions under the regulatory framework through the operating expenditure allowance (and had done so)

39 ibid, p. 9.
40 See NER clause 6.6.3.
41 See NER clause 6.6.3A .
42 See: https://www.aemc.gov.au/rule-changes/demand-management-embedded-generation-connection-i
43 AEMC, *Demand management incentive scheme, Rule Determination*, August 2015, p. iii.
44 See: https://www.aemc.gov.au/rule-changes/implementation-of-demand-management-incentive-sche
45 AEMC, *Demand management incentive scheme, Rule Determination,* August 2015, pp. 27–28.

- ultimately, consideration of the application of the DMIS and DMIA for transmission network regulation was out of scope of the rule change proposal.

A.4. Incentive regulation under the current regulatory framework

The AER sets revenue and financial incentives for TNSPs and DNSPs over a forward-looking period – usually five years. The allowed revenue is the basis for network charges, which are a component of electricity retailer bills. Network charges represent around half of the average residential bill.

The AER must take into account the price, quality, safety, reliability and security of supply of energy.[46] In addition, the AER must consider the revenue and pricing principles under the NEL, which support the NEO.

Key aspects of the revenue and pricing principles are that regulated network service providers (NSPs) should be provided with:

- a reasonable opportunity to recover at least their efficient costs of providing network services and complying with regulatory obligations
- effective incentives to promote economic efficiency.[47]

The NER require the AER to use the building blocks approach to determine how much revenue an NSP needs to cover its 'efficient costs' over the coming regulatory period. The AER uses the building blocks approach to forecast and lock-in the total revenue that an efficient and prudent business would require. In doing so, the AER takes into account expected demand and cost inputs, all applicable regulatory obligations or requirements on the business, and the reliability, security and safety of the network (among other things).

Under the incentive-based regulatory framework, the AER sets an ex-ante revenue allowance and the NSPs are expected to attempt to outperform it. Networks that allow their efficiency to deteriorate earn lower profits. Networks that improve their efficiency are rewarded with higher profits – they are allowed to keep a proportion of the difference between their approved forecasts and their actual expenditure.

The AER applies various incentive schemes, such as the EBSS, CESS and STPIS, to provide NSPs with a continuous incentive to improve their efficiency in supplying electricity services – while maintaining or improving service standards. The EBSS and CESS share operating and capital efficiency gains, respectively, between networks and consumers on roughly a 30:70 basis. The NSPs retain about 30 per cent of the efficiency gain (in NPV terms), while consumers retain 70 per cent of the savings.

To discourage NSPs from cutting costs by reducing service levels the AER applies a STPIS, which rewards or penalises networks for their outage performance and, in the case of TNSPs, for the level of network constraints. This supplements the planning standard obligations in state legislation (where applicable).

46 See NEL Section 7.

47 See NEL Section 7A.

TNSPs must already apply a RIT-T prior to making significant network investments.[48] The purpose of the RIT-T process is to identify the 'credible option' that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market. The RIT-T requires all credible options to be examined. Credible options include non-network options.[49]

The DMIS and DMIA are other regulatory mechanisms that can be used to incentivise efficient outcomes to the benefit of consumers.

A.5. Economic regulatory framework review

The Commission's Economic regulatory framework review is an annual review that examines whether network regulation continues to support the delivery of the NEO in light of the changes in the energy market – particularly with the increasing penetration of distributed energy resources (DER).[50] Through this review, the Commission monitors changes and developments in the National Electricity Market, and examines whether the economic regulatory framework is sufficiently robust and flexible and continues to support the efficient operation of the energy market in the long term interests of consumers.

The Commission is currently consulting on potential alternative approaches to expenditure assessment and remuneration to address the potential for expenditure bias – which implements one of the recommendations from the *Independent Review into the Future Security of the National Electricity Market* (the Finkel Review).[51] The Commission stated 'several potential solutions may be available to address the risk of bias, and reforms could range from refinements to the existing framework to recommending new approaches for setting revenues for regulated businesses.'[52] (Indeed, one of the key rationales put forward by ENA in support of its proposed rule change is unbalanced incentives.)

The Commission is required to publish the review report annually by 30 June. The Commission has extended the timeline of the *2019* E*conomic regulatory framework review* to align with the draft rule determination on this rule change – that is, both reports will be published by 19 September 2019. ENA's rule change request is directly relevant to the Commission's work on the 2019 Review. Delaying completion of the review allows the Commission to consider the issues in a more coordinated way.

48 See NER clauses 5.15 and 5.16.
49 See NER clause 5.15.2.
50 See: https://www.aemc.gov.au/market-reviews-advice/electricity-network-economic-regulatory-framework-review-2019
51 *Independent Review into the Future Security of the National Electricity Market*, June 2017, p. 152.
52 AEMC, *2019 Economic regulatory framework review: Approach paper*, 17 January 2019, pp. 11–14.