PRELIMINARY DECISION
Ergon Energy determination
2015−16 to 2019−20

Attachment 12 − Demand management incentive scheme

April 2015

AUSTRALIAN
ENERGY
REGULATOR

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Note

This attachment forms part of the AER's preliminary decision on Ergon Energy's 2015–20 distribution determination. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

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Attachment 18 – Connection policy

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators

Shortened form	Extended form
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

12 Demand management incentive scheme

The National Electricity Rules (NER) require us to develop and implement mechanisms to incentivise distributors to consider efficient alternatives to building more network.[1] To meet this requirement, and motivated by the need to improve distributors' capability in the demand management area, we implemented a demand management incentive scheme (DMIS) in our Queensland distribution determinations for the 2010–15 regulatory control period.[2]

The current DMIS for Queensland distributors includes the demand management innovation allowance (DMIA)[3].

The DMIA is a capped allowance for distributors to investigate and conduct broad-based and/or peak demand management projects. It contains two parts:

- Part A provides for an innovation allowance to be incorporated into each distributor's revenue allowance for opex each year of the regulatory control period. Distributors prepare annual reports on their expenditure under the DMIA[4] in the previous year, which we then assess against specific criteria.[5]
- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A. During the 2010–15 regulatory control period, Queensland distributors were subject to a revenue cap form of control. As the revenue cap will continue in the 2015–20 regulatory control period, Part B remains not relevant to Queensland distributors.

Currently, only Part A of the scheme applies to the Queensland distributors.

Under the scheme, we return any underspend against the allowance to customers. Also, once we know the approved DMIA expenditure for each year of the current period, we compensate distributors for approved foregone revenue. We implement this as an adjustment to each distributor's innovation allowance in the following regulatory control period.

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1 NER, cl. 6.6.3(a).

2 The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS includes embedded generation. We consider embedded generation to be one means of demand management, as it typically reduces demand for power drawn from a distribution network.

3 AER, *Demand management incentive scheme – Energex, Ergon Energy and ETSA Utilities: 2010–15*, 17 October 2008. (AER, DMIA for QLD and SA distributors, October 2008).

4 The DMIA excludes the costs of demand management initiatives approved in our determination for the 2010–15 regulatory control period.

5 AER, DMIA for QLD and SA distributors, October 2008, pp. 5–6.

12.1 Preliminary decision

We have determined to continue Part A of the DMIA for Ergon Energy in the 2015–20 regulatory control period. This is consistent with our proposed approach in our Framework and Approach (F&A).[6]

The current innovation allowance amount of $1 million ($2014–15) per annum will continue in the 2015–20 regulatory control period.

12.2 Ergon Energy's proposal

Ergon Energy supported the proposed approach set out in our F&A to continue applying Part A of the DMIA at the same scale as is currently applied.[7]

Ergon Energy acknowledged the AEMC's Power of Choice review which includes an examination of distributor incentives to pursue efficient alternatives to network augmentation and anticipates new rules and principles guiding the design of a new DMIS.[8]

12.3 AER’s assessment approach

The rules require us to have regard to several factors in developing and implementing a DMIS for Ergon Energy.[9] These are:

- Benefits to consumers
    - the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
    - the willingness of customers or end users to pay for increases in costs resulting from implementing DMIS.
- Balanced incentives
    - the effect of a particular control mechanism (i.e. price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
    - the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
    - the extent the distributor is able to offer efficient pricing structures
    - the possible interactions between DMIS and other incentive schemes.

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6 AER, *Final Framework and Approach paper for Energex and Ergon Energy,* 30 April 2014, pp. 124-125. (AER, Framework and Approach, April 2014).

7 Ergon Energy, *Ergon Energy Regulatory Proposal 2015 to 2020,* 31 October 2014, pp. (Ergon Energy, Regulatory Proposal, October 2014).

8 Ergon Energy, Regulatory Proposal, October 2014, Appendix 03.01.03 Application of Incentive Schemes, pp. 3-4.

9 NER, cl 6.6.3(b).

We had regard to these factors in considering the proposed approach to the DMIS for Ergon Energy as set out in our F&A[10] and we have again taken these factors into account in making our preliminary decision.

12.4 Reasons for preliminary decision

Considering a significant proportion of Ergon Energy's allowance remains for the 2010–2015 regulatory control period[11], we have determined that the current innovation allowance amount of $1 million ($2014–15) per annum will continue in the 2015–20 regulatory control period.

Our F&A stated that our intention to develop and implement a new DMIS for the 2015–20 regulatory control period was dependent on the progress of the rule change process arising from the AEMC's Power of Choice review.[12] On 19 February 2015, the AEMC commenced consultation on the rule change. Submissions closed on 19 March 2015. The AEMC is currently considering the rule amendments.

The Total Environment Centre (TEC) accepted the position we adopted in our F&A to await the outcomes of the AEMC's review before considering reform of the current DMIS but suggested that we consider introducing measures to promote the effective use of demand management initiatives. Such measures included requiring businesses to report annually, providing businesses with specific metrics or performance indicators and the development of a demand management guideline.[13]

The Local Government Association of Queensland questioned the need for a DMIS and asked that we carefully consider the merits of proposed research focused demand management projects before allowing DMIA expenditure considering off-grid demand management solutions already exist.[14]

In response to submissions and consistent with our F&A, we do not intend to pre-empt consultation on the AEMC's review of the current demand management arrangements by commencing a separate consultation process on a new DMIS before the outcomes of the review are finalised. Quite apart from the unnecessary complications and inefficiencies that a parallel policy process would create, the confines of a distribution revenue review make it ill-suited to driving regulatory reform.

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10 AER, Framework and Approach, April 2014, p. 126.

11 AER, *Applications by DNSPs for Demand Management Innovation Allowance for 2013 calendar year (Victorian DNSPs) and 2012–13 financial year (all other DNSPs),* April 2015, p. 4.

12 AER, Framework and Approach, April 2014, p. 124-125. For information regarding the AEMC's Power of Choice Review, see http://www.aemc.gov.au/Major-Pages/Power-of-choice. The AEMC received a proposed rule change from COAG Energy Ministers and the Total Environment Centre.

13 Total Environment Centre, *Submission to the AER on Queensland distribution networks' 2015–2020 revenue proposals*, February 2015, pp. 5-6 & 20.

14 Local Government Association of Queensland, *Submission on Queensland distributors' regulatory proposals 2015–20,* 30 January 2015, p.1.

We acknowledge the need to reform the existing demand management incentive arrangements and the importance of demand management in deferring the need for network augmentation by alleviating network utilisation during peak usage periods. The move to a revenue cap form of control removes any disincentive for distributors to reduce the quantity of electricity sold by pursuing demand management initiatives. More robust obligations to consider non-network alternatives in order to satisfy RIT-D requirements provide distributors with opportunities to improve and expand their demand management programs.

Beyond increasing opportunities, we recognise the importance of strengthening demand management incentives in order to defer network augmentation. However, we do not consider it appropriate to develop an alternative incentive structure in parallel to the AEMC's review through Ergon Energy's regulatory proposal. The AEMC will be able to consider how any changes to the NER can be implemented in the 2015–20 regulatory control period through transitional arrangements.

For these reasons, we have adopted the position proposed in our F&A and approved DMIA allowances consistent with their current scale. We will consider the introduction of a revised DMIS as soon as practicable following the AEMC's rule change process.

Ergon Energy proposed a number of demand management costs as part of its total forecast operating expenditure building block. Our decision on Ergon Energy's demand management related operating expenditure building block can be found in attachment 7.