

Draft Decision

ActewAGL distribution determination

2015–16 to 2018–19

Attachment 12: Demand management incentive scheme

November 2014

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1. AER reference: 52254
2. Note
3. This attachment forms part of the AER's draft decision on ActewAGL’s 2015–19 distribution determination. It should be read with other parts of the draft decision.
4. The draft decision includes the following documents:
5. Overview
6. Attachment 1 – Annual revenue requirement
7. Attachment 2 – Regulatory asset base
8. Attachment 3 – Rate of return
9. Attachment 4 – Value of imputation credits
10. Attachment 5 – Regulatory depreciation
11. Attachment 6 – Capital expenditure
12. Attachment 7 – Operating expenditure
13. Attachment 8 – Corporate income tax
14. Attachment 9 – Efficiency benefit sharing scheme
15. Attachment 10 – Capital expenditure sharing scheme
16. Attachment 11 – Service target performance incentive scheme
17. Attachment 12 – Demand management incentive scheme
18. Attachment 13 – Classification of services
19. Attachment 14 – Control mechanism
20. Attachment 15 – Pass through events
21. Attachment 16 – Alternative control services
22. Attachment 17 – Negotiated services framework and criteria
23. Attachment 18 – Connection methodology
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1. Shortened forms

| 1. Shortened form
 | 1. Extended form
 |
| --- | --- |
| 1. AARR
 | 1. aggregate annual revenue requirement
 |
| 1. AEMC
 | 1. Australian Energy Market Commission
 |
| 1. AEMO
 | 1. Australian Energy Market Operator
 |
| 1. AER
 | 1. Australian Energy Regulator
 |
| 1. ASRR
 | 1. aggregate service revenue requirement
 |
| 1. augex
 | 1. augmentation expenditure
 |
| 1. capex
 | 1. capital expenditure
 |
| 1. CCP
 | 1. Consumer Challenge Panel
 |
| 1. CESS
 | 1. capital expenditure sharing scheme
 |
| 1. CPI
 | 1. consumer price index
 |
| 1. CPI-X
 | 1. consumer price index minus X
 |
| 1. DRP
 | 1. debt risk premium
 |
| 1. DMIA
 | 1. demand management innovation allowance
 |
| 1. DMIS
 | 1. demand management incentive scheme
 |
| 1. distributor
 | 1. distribution network service provider
 |
| 1. DUoS
 | 1. distribution use of system
 |
| 1. EBSS
 | 1. efficiency benefit sharing scheme
 |
| 1. ERP
 | 1. equity risk premium
 |
| 1. expenditure assessment guideline
 | 1. expenditure forecast assessment guideline for electricity distribution
 |
| 1. F&A
 | 1. framework and approach
 |
| 1. MRP
 | 1. market risk premium
 |
| 1. NEL
 | 1. national electricity law
 |
| 1. NEM
 | 1. national electricity market
 |
| 1. NEO
 | 1. national electricity objective
 |
| 1. NER
 | 1. national electricity rules
 |
| 1. NSP
 | 1. network service provider
 |
| 1. opex
 | 1. operating expenditure
 |
| 1. PPI
 | 1. partial performance indicators
 |
| 1. PTRM
 | 1. post-tax revenue model
 |
| 1. RAB
 | 1. regulatory asset base
 |
| 1. RBA
 | 1. Reserve Bank of Australia
 |
| 1. repex
 | 1. replacement expenditure
 |
| 1. RFM
 | 1. roll forward model
 |
| 1. RIN
 | 1. regulatory information notice
 |
| 1. RPP
 | 1. revenue pricing principles
 |
| 1. SAIDI
 | 1. system average interruption duration index
 |
| 1. SAIFI
 | 1. system average interruption frequency index
 |
| 1. SLCAPM
 | 1. Sharpe-Lintner capital asset pricing model
 |
| 1. STPIS
 | 1. service target performance incentive scheme
 |
| 1. WACC
 | 1. weighted average cost of capital
 |

# Demand management incentive scheme

1. The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.[[1]](#footnote-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 NSW/ACT distribution determinations for the 2009–14 regulatory control period.[[2]](#footnote-2)
2. The current DMIS for ActewAGL includes two components—the demand management innovation allowance (DMIA)[[3]](#footnote-3) and the D-factor.[[4]](#footnote-4)
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[[5]](#footnote-5) in the previous year, which we then assess against specific criteria.[[6]](#footnote-6)
* Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A. In the 2009–14 and 2014–15 regulatory control periods, ActewAGL was subject to an average revenue cap form of control. As the average revenue cap will continue in the 2015–19 regulatory control period, Part B is not relevant to ActewAGL.
1. Currently only Part A of the scheme applies to ActewAGL.
2. Under the scheme, we return any underspend against the allowance to customers and compensate distributors for approved foregone revenue, once we know their approved DMIA expenditure for each year of the current period. We implement this as an adjustment to each distributor's innovation allowance in the following regulatory control period.

## Draft decision

1. We have determined to continue Part A of the DMIA for ActewAGL in the 2015–19 regulatory control period. This is consistent with our proposed approach in the Stage 2 Framework and Approach and it is also consistent with the approach we took in the transitional regulatory control period.[[7]](#footnote-7)
2. The current innovation allowance amount of $0.1 million ($2014–15) per annum will continue in the 2015–19 regulatory control period.

## ActewAGL's proposal

1. ActewAGL supported our proposed approach, as set out in the Stage 2 Framework and Approach, to continue applying Part A of the DMIA at the same scale as is currently applied.[[8]](#footnote-8)
2. Regarding anticipated changes to the DMIS, ActewAGL stated it was unclear how a new scheme could apply once the final revenue determination for the 2015–19 regulatory control period had been made. To address this concern, ActewAGL proposed that a pass through event be included in the final determination to allow recovery of any change in costs, including incentives, incurred by ActewAGL in implementing demand management projects under a new scheme.[[9]](#footnote-9)

## AER's assessment approach

1. The rules require us to have regard to several factors in developing and implementing a DMIS for ActewAGL.[[10]](#footnote-10) 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 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.

## Reasons for draft decision

Our Stage 2 Framework and Approach stated that our intention to develop and implement a new DMIS for the 2015–19 regulatory control period was dependent on the progress of the rule change process arising from the AEMC’s Power of Choice review.[[11]](#footnote-11) At the time of this draft decision, the AEMC expects to commence consultation on the rule change requests received in the first quarter of 2015.

1. Regarding demand management incentives generally, the Consumer Challenge Panel submitted that we should consider using rewards and penalties to encourage new approaches to demand management.[[12]](#footnote-12)
2. 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.
3. 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, thereby removing any disincentive for distributors to reduce the quantity of electricity sold by pursuing demand management initiatives, and 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.
4. Beyond increasing opportunities, we recognise the importance of strengthening demand management incentives in order to defer network augmentation. However, we consider that proposals to revise the current DMIS deserve the full scrutiny of a consultative rule change process by the AEMC and a subsequent scheme development process by the AER to ensure a robust outcome. For these reasons, we have adopted the position proposed in the Stage 2 Framework and Approach and approved DMIA allowances consistent with their current scale.

We intend to introduce a revised DMIS as soon as practicable following the AEMC's rule change process. It is likely that transitional rules will be required to allow the revised scheme to apply within the 2015–19 regulatory control period.

1. ActewAGL proposed demand management projects for the 2015–19 regulatory control period will be funded through the DMIS. ActewAGL did not propose any demand management projects as part of its opex or capex allowances.[[13]](#footnote-13) The DMIS provides for an ex post review of claims for funding through the DMIS.[[14]](#footnote-14) We do not need to make a decision at this time on whether ActewAGL's proposed projects are consistent with, or likely to be consistent with, the criteria for funding under the DMIS.
2. Our consideration of ActewAGL's proposed DMEGCIS pass through event is set out in attachment 15.
1. NER, cl 6.6.3(a). [↑](#footnote-ref-1)
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 include 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. [↑](#footnote-ref-2)
3. AER, Demand management incentive scheme for the ACT and NSW 2009 distribution determinations—Demand management innovation allowance scheme, 28 November 2008. (AER, DMIA for ACT and NSW distributors, Nov 2008). [↑](#footnote-ref-3)
4. AER, Demand management incentive scheme for the ACT and NSW 2009 distribution determinations—D-factor scheme, 29 February 2008. [↑](#footnote-ref-4)
5. The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009–14 regulatory control period or under the D-factor scheme. [↑](#footnote-ref-5)
6. AER, DMIA for ACT and NSW distributors, Nov 2008, pp. 4–5. [↑](#footnote-ref-6)
7. AER, Stage 2 Framework and Approach paper for ActewAGL, January 2014, p 32 (AER, Stage 2 Framework and Approach, Jan 2014). [↑](#footnote-ref-7)
8. ActewAGL, Subsequent Regulatory Proposal: 2015–19 regulatory control period – Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory, 2 June 2014, p. 144 (ActewAGL, Regulatory Proposal, Jun 2014). [↑](#footnote-ref-8)
9. ActewAGL, Regulatory Proposal, June 2014, pp. 385–388. [↑](#footnote-ref-9)
10. NER, cl 6.6.3(b). [↑](#footnote-ref-10)
11. AER, Stage 2 Framework and Approach, January 2014, p 32. 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. [↑](#footnote-ref-11)
12. Consumer Challenge Panel, Submission to the AER from the Consumer Challenge Panel regarding ActewAGL regulatory proposal, 2014–19, August 2014, p. 20. [↑](#footnote-ref-12)
13. ActewAGL, Regulatory Proposal, June 2014, pp. 144–148. [↑](#footnote-ref-13)
14. AER, DMIA for ACT and NSW distributors, Nov 2008, pp. 3–4. [↑](#footnote-ref-14)