



Consultation paper

Demand management incentive scheme and innovation allowance mechanism

January 2017

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Allowance Mechanism	demand management innovation allowance mechanism
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG Energy Council	Council of Australian Governments Energy Council
Current Scheme	the demand manage incentive scheme or the demand management and embedded generation connection incentive scheme that the AER currently applies to distributors
DAPR	distribution annual planning report
DER	distributed energy resources
distributor	distribution network service provider
DMIA	the demand management innovation allowance under Part A of the Current Scheme
EBSS	efficiency benefit sharing scheme
GW	gigawatts
MW	megawatts
MWh	megawatt hours
NEM	national electricity market
NPV	net present value
opex	operating expenditure
the Planning Framework	the national Distribution Network Planning and Expansion Framework
R&D	research and development
RIT-D	regulatory investment test for distribution
the rules	the National Electricity Rules
Scheme	demand management incentive scheme
STPIS	service target performance incentive scheme
TEC	Total Environment Centre
WACC	weighted average cost of capital
WAPC	weighted average price cap

1 About this consultation

This Consultation Paper is our second engagement step with stakeholders in developing a new demand management incentive scheme (Scheme) and innovation allowance mechanism (Allowance Mechanism).

This is where we are designing the Scheme to reward distribution network service providers (distributors) for implementing proven and efficient non-network options and technology. Its objective under the National Electricity Rules (rules) is to:¹

provide Distribution Network Service Providers with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management (the demand management incentive scheme objective).

In contrast, we are designing the Allowance Mechanism to reward investment in unproven technologies and solutions. Its objective under the rules is to:²

provide Distribution Network Service Providers with funding for research and development in demand management projects that have the potential to reduce long term network costs (the demand management innovation allowance objective).

This Consultation Paper discusses different mechanisms that could constitute or be part of a new Scheme and Allowance Mechanism. We have grouped different mechanisms into four broad types of Scheme design options. We have also provided an initial assessment of four Allowance Mechanism design options against our assessment framework. In developing options, we have taken into account the various issues submitted by stakeholders via our survey, which were subsequently discussed at our Issues Day workshop on 20 September 2016. We have also taken into account the views expressed during presentations at the Issues Day workshop. Some of these views have included:

- Keep the Scheme and Allowance Mechanism simple.
- Consider the Scheme and Allowance Mechanism on their economic benefits, since consumers will bear the costs associated with them.
- Consider whether there is a real incentive for network management.
- Be careful not to incentivise distributors in a way that undermines the competitive segment of the market to deliver.
- Base the value of demand management on an assessment of the deferred value of avoided network costs.

¹ NER, cl. 6.6.3(b) and 3(c).

² NER, cl. 6.6.3A(b).

- Consider ways to help put operating expenditure (opex) and capital expenditure (capex) on a relatively equal footing.
- Act quickly in deploying incentives and funds now; particularly to drive smaller third party demand management providers.

Our website provides a summary of the discussions that took place at the Issues Day workshop.³ It also provides slides of the presentations made on the day.

This Consultation Paper:

- Provides a brief background on demand management, the rule change and where this project fits into the regulatory framework.
- Articulates the framework we are going to apply to develop a Scheme and Allowance Mechanism to give effect to the rules.
- Discusses incentives currently available and potential obstacles for demand management that we heard from stakeholders.
- Sets out several types of Scheme design options for discussion and our initial thoughts on information and reporting requirements.
- Sets out several types of Allowance Mechanism design options for discussion and our initial thoughts on information and reporting requirements.
- Includes Appendix A, which explains how our current demand management incentive scheme (the Current Scheme) operates and analyses its impact to date.

Invitation for submissions

While we welcome submissions across the broad range of stakeholders interested in demand management, this Consultation Paper assumes a good understanding of how demand management operates within network regulation. We are particularly interested in submissions that will assist us in developing a Scheme and an Allowance Mechanism that are possible, functional, address what is important to you and meet their respective objectives.

We encourage submissions by 24 February 2017 that will assist us in developing the draft Scheme and Allowance Mechanism. Please email your submissions to DM@aer.gov.au. Alternatively, you can mail a hard copy of your submission to:

Mr Warwick Anderson
 General Manager, Network Regulation
 Australian Energy Regulator
 GPO Box 3131
 Canberra ACT 2601

³ AER, *Breakout session discussion notes summary*, September 2016, <https://www.aer.gov.au/system/files/AER%20-%20Breakout%20session%20discussion%20notes%20summary%20-%202020%20September%202016.pdf>.

We prefer to make written submissions public to inform continued robust and transparent debate. We will treat submissions as public documents and post them on our website, unless you make prior arrangements with us to treat the submission, or portions of it, as confidential.

If you are wishing to submit confidential information, we request you:

- clearly identify the information that is the subject of the confidentiality claim; and
- provide a non-confidential version of the submission
- we prefer electronic submissions (Microsoft Word file or other text readable document).

We encourage submissions to provide your views on and supporting reasons on the questions we ask throughout this paper. These include:

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.
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.
3. 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?
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)?
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.
6. If you have views against applying any of the particular mechanisms discussed in section 6, please provide reasons to support this view.
7. How we might best give effect to or enhance the information and reporting requirements discussed in section 6.5?
8. 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.
9. If you have views against applying any of the particular mechanisms discussed in section 7, please provide reasons to support this view.

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

Next steps

Following the submission period, you will have further opportunity to participate in an Options Day workshop in March 2017. We would also welcome the opportunity to engage with you to discuss this review upon request.

Table 1 summarises our indicative project timeline in developing the Scheme and Allowance Mechanism. We will have a new Scheme and Allowance Mechanism in place to apply to the NSW distribution network service providers (distributors) in their next regulatory control period.⁴

Table 1: Indicative project timeline

Project step	Date
Submissions on Consultation Paper close	24 February 2017
Scheme design options workshop	March 2017
Draft Scheme and Allowance Mechanism published	May 2017
Submissions on draft close	June 2017
Workshop on the draft Scheme and Allowance Mechanism	July 2017
Final Scheme and Allowance Mechanism published	September 2017

⁴ We anticipate finalising the new Scheme and Allowance Mechanism around the end of the 2016/17 financial year.

2 Overview

There is great interest in the deployment of demand management, which we define as the act of modifying the drivers of network usage, including reducing peak demand or changing the demand profile. However, we have seen very little effective use of demand management to date.

We explore the reasons for why there appears to have been less than expected demand management deployment, despite the strong community interest we are currently witnessing. Through our research and consultation, stakeholders have proffered a large number of reasons/obstacles, including:

- Demand management is not efficient and/or effective.
- The market for the supply of demand management is underdeveloped.
- There is a lack of enabling technologies.
- There is a lack of information on the capabilities of demand management solutions.
- Cultural biases within distributors and other network businesses.
- The regulatory allowed rate of return is too high, favouring capital investments by distributors and other network businesses.
- Distributors are unable to capture the full benefits of demand management while they bear the majority of costs.
- Distributors are unable to profit from demand management solutions.
- There are biases within the regulatory framework and an absence of effective incentives.
- There is a lack of information on upcoming network constraints.
- The operation of service standards and the perceived unreliability of demand management solutions.
- The inclusion of liability clauses in contracts offered to third party demand management providers by distributors and other network businesses.
- Demand for energy has decreased, including moderation in peak demand avoiding new constraints on the networks.

It is likely that a number of these have led to the deployment of demand management being low relative to stakeholder expectations. Given this, we will need to develop a new Scheme to address a number of factors whilst staying within the scope of the regulatory framework. Nevertheless, on the basis of the consultation we have conducted so far, we are confident that we can take steps to encourage greater use of efficient demand management.

We discuss a range of different mechanisms that we could use in different combinations to form alternative Scheme design options. These mechanisms aim to meet the Scheme's objective by addressing barriers that appear to hinder efficient

demand management, despite the positive incentives within the regulatory framework. Given the drivers of demand management incentives are multifaceted; it is most likely that a combination of mechanisms would assist in the final Scheme design.

Any initiatives adopted by us will be most effective if they are targeted at the most influential drivers of demand management. We invite stakeholders to focus their submissions on the options which address the most influential drivers. We are currently in the engagement stage and have not formed a definitive view on our preferred Scheme design option/s.

Without constraining the scope of submissions, we offer preliminary thoughts on the current barriers and potential Scheme and Allowance Mechanism options. We have based this on our consultation undertaken to date and our review of the literature. For instance, the barriers to demand management that seem most prominent to us and that the Scheme could address include the:

- Lack of information on upcoming network constraints.
- Lack of information on what demand management solutions can deliver.
- Underdeveloped state of the market for demand management solutions.
- Potentially, cultural biases within distributors.⁵

The incentives we provide under the Scheme must target expenditure on efficient non-network options relating to demand management.⁶ Non-network options involve non-network assets that are deployed to address a constraint either alone or in conjunction with network assets. Non network options would also include assets on which someone other than a distributor undertakes expenditure. The most important criterion for the Allowance Mechanism is that it provides distributors with funding for research and development (R&D) in demand management projects that have the potential to reduce long term network costs.⁷

Based on the Scheme objective and the list of obstacles, we see particular value in exploring the mechanisms categorised as 'mechanisms to promote competition'.⁸ These types of mechanisms aim to incentivise distributors to undertake efficient demand management by building the capacity of the contestable market to deliver efficient demand management. These include mechanisms that:

- Provide distributors with an incentive to publish detailed information on upcoming network constraints in a way that is readily accessible to demand management providers.

⁵ A Scheme could help overcome potential cultural biases by providing targets or high-powered incentives. It could also address a cultural aversion to outsource demand management to third party providers by providing incentives to encourage market delivery of demand management.

⁶ NER, 6.6.3(b) – demand management incentive scheme objective.

⁷ NER, cl. 6.6.3A(b) – demand management innovation allowance objective.

⁸ We discuss these under section 6.3.

- Provide distributors with an incentive to develop a transparent bidding mechanism to attract least cost non-network alternatives to upcoming constraints and promote the development of the market for the third party provision of demand management. As part of this, we could fund distributors to develop a standard form contract for demand management. This contract should appropriately balance the interests of all parties and clearly identify the risk of failing to deliver the contracted amount of demand management. It should also identify the party that is underwriting such risks.

We discuss four design options that have the potential to meet the new Allowance Mechanism objective:

- Minor extension to the status quo. This is where the 'status quo' is the demand management innovation allowance (DMIA) under the Current Scheme.
- High cap allowance with ex-ante approval.
- Bidding to encourage 'ground breaking' R&D.
- Bidding to encourage market-facilitated R&D.

Based on the Allowance Mechanism's objective, at this early stage we see particular value in exploring further the latter option to provide a bidding mechanism to encourage market-facilitated R&D.

We also recognise that different stakeholders may hold alternative views as to which mechanisms under the Scheme or which Allowance Mechanism design option appears most promising to them. In light of this, we welcome your views on the benefits and limitations of these different options, and which of these you would prefer us to explore further.

3 Background

There is great interest in the deployment of demand management. We are seeing policy development in demand management at different levels of government. We are seeing new partnerships form to explore demand management deployment, such as those between government, community groups and network businesses.⁹ We are seeing increasing involvement and sophistication in this area among generators, retailers, various demand management providers and consumers in general. Our consultation on this topic has attracted a great amount of participation. Interested parties are motivated by a range of reasons to deploy non-network solutions, including:

- Seeking independence from traditional energy suppliers.
- Exercising control over energy prices that have increased rapidly in recent years.
- Environmental benefits, including greater use of renewable energy and avoidance of carbon emissions.
- Efficient supply of network services and avoidance of capex.
- Greater flexibility in energy supply and usage.
- Advancements in technology.¹⁰

3.1 Background to the regulatory framework

We apply an economic regulatory framework to distributors, which exhibit natural monopoly characteristics. Under this, we provide distributors with an ex-ante allowance to cover their efficient costs, which they can then decide on how to best deploy. This framework aims to incentivise distributors to pursue the most efficient solution, irrespective of whether it is a network or non-network solution, and whether a third party or the distributor provides the solution.

In addition to financial incentives, the framework also includes requirements to assist distributors in pursuing efficient demand management options. These include components of the Distribution Network Planning and Expansion Framework (the Planning Framework) to ensure fuller consideration of non-network options.

Distributors currently have access to the Current Scheme that operates as a modest innovation allowance in practice. The Council of Australian Governments (COAG) Energy Council and the Total Environment Centre (TEC) considered the Current

⁹ For example, the Future Energy Planning project seeks to build better collaboration between electricity networks and local government planners in Victoria. See <http://www.naga.org.au/future-energy-planning.html>.

¹⁰ AER, *Breakout session discussion notes summary*, September 2016, <https://www.aer.gov.au/system/files/AER%20-%20Breakout%20session%20discussion%20notes%20summary%20-%202020%20September%202016.pdf>

Scheme insufficient and sought a rule change.¹¹ Essentially, they considered it had insufficiently driven behaviour to achieve the full potential of cost-efficient demand management by distributors. Moreover, stakeholders were of the view that the current regulatory framework created a bias against non-network options. A number of concerns drove this. Some considered that the regulatory framework disincentivised demand management. Further, distributors had no apparent financial incentive to factor in the broader market benefits from non-network options. These were also considered impediments to the trialling of new non-network options under the Current Scheme. We provide a review of the Current Scheme in Appendix A and agree that it has not appeared effective in encouraging an efficient level of demand management.

We are developing the new Scheme to address the concerns that the regulatory framework does not encourage distributors to undertake non-network options where we consider these concerns reflect genuine barriers to efficient demand management.¹² The Allowance Mechanism will fund project R&D to drive innovation in non-network solutions. Once projects reach commercialisation, they should no longer require additional funding to deploy, but rather be considered as credible alternatives to network investments. These projects will compete with the more traditional network options deployed to satisfy demand growth and/or changing patterns, once it has been trialled and proved ready for commercialisation. We see projects incubated through our Allowance Mechanism moving to efficient expenditure due to a newer and better Scheme. Projects stepping from research trials to commercialisation will drive more competition between network and non-network options, resulting in outcomes that are in the long term interest of consumers.¹³

When developing the Scheme and Allowance Mechanism, we should have regard to how changing consumer preferences and emerging technologies have been transforming energy markets and networks. This advent of more diverse options is providing greater choice and control over how consumers use energy services. Our new Scheme and Allowance Mechanism will add to our other ongoing work in this space including tariff reform, metering contestability, the national ring fencing guideline and rules to strengthen the transparency and efficiency of replacement expenditure.

3.2 Background to demand management

In the context of the Scheme development, we define demand management as the act of modifying the drivers of network usage, including reducing peak demand or changing the demand profile. This is in contrast to what is a supply-side action, which entails investment to increase the network capacity to satisfy demand.

¹¹ SCER, *Reform of the DMEGCIS rule change request*, December 2013; TEC, *DMIS rule change request: Submission to AEMC*, November 2013.

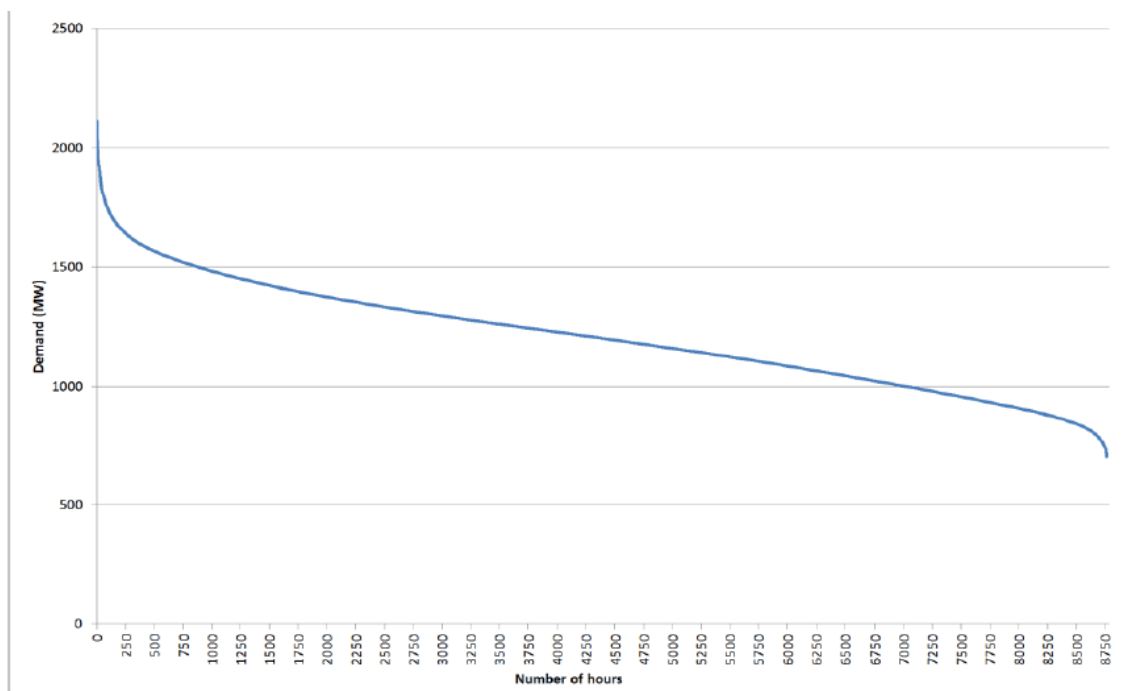
¹² AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, p. 6. This rule followed from the AEMC's Power of Choice review. See AEMC, *Power of choice review: Final report*, November 2012.

¹³ National Electricity Objective, NEL s.7.

For the purposes of this Consultation Paper, we have not defined distributed energy resources (DER). Reference to DER in the literature is generally adopted to refer to solutions that are deployed to achieve demand management/customer control, particularly with a focus away from the traditional centralised electricity supply model and includes new technologies.

Networks are built to meet peak demand. However networks only hit their peak for a limited time in the year. At all other times, the network is underutilised. For example, Figure 1 illustrates this with a typical load duration curve for a distributor, using Powercor in 2015 as an example. This illustrates that while demand in Powercor's distribution network reached well over 2,000 MW in 2015, it was only at that level for a few hours in that year.

Figure 1: Example of a load duration curve



Source: CitiPower/Powercor, *Demand side engagement strategy*, 25 July 2016, v.2.0, Figure 3.2.

Demand management can reduce or shift the peak and provide a less costly alternative to network investment. Demand management options can be particularly valuable when there are difficulties in forecasting peak demand growth. This is because, unlike network options, demand management options tend not to lock in long-term irreversible investments. As such, these options can have considerable 'option value' or flexibility benefits.

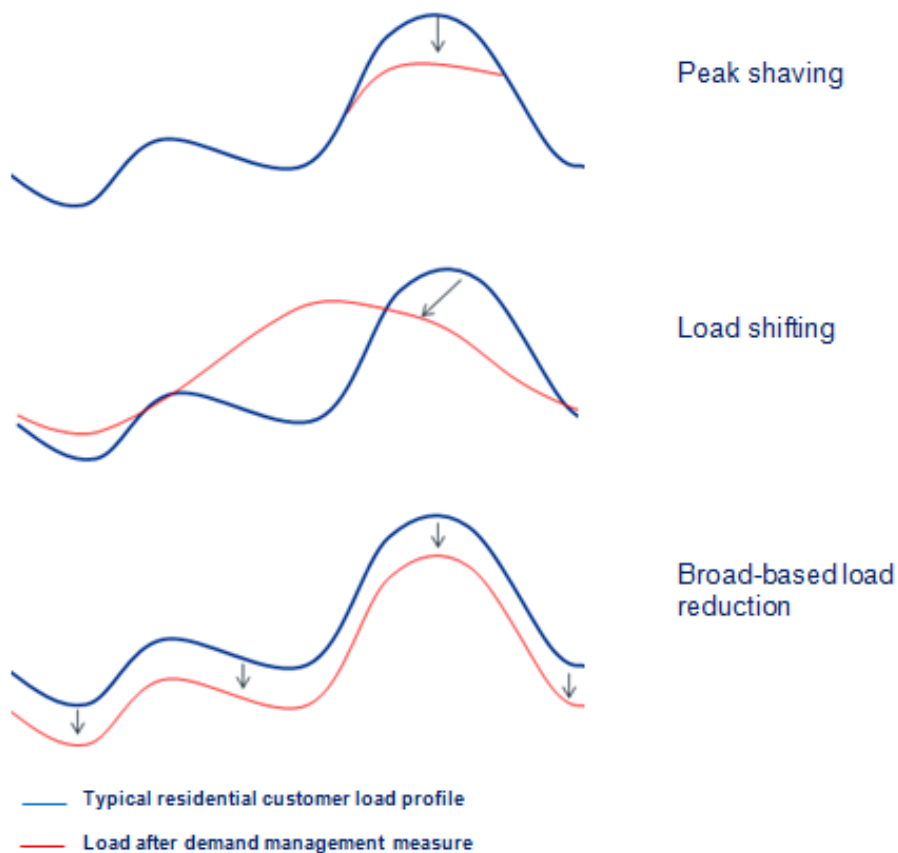
Distributors can shift or reduce consumer demand through various methods, such as providing financial incentives to encourage behavioural change, providing local generation support or physically controlling electricity usage.

We note that distributors might value demand management options relating to behavioural change, local generation and physical control of electricity usage differently. This is due to:

- **Controllability:** Behavioural change and local generation that the distributor cannot dispatch can potentially address periods of peak demand. However, since the distributor is unable to guarantee dispatch, it would provide this option based on an expectation of performance given previous consumer behaviour. As such, the distributor will 'discount' the value of this type of capacity. In contrast, generation or customer loads that the distributor can dispatch offer a higher level of firmness and therefore value. This is also true of 'passive' demand management technologies, such as energy efficiency.
- **Timing:** If a distribution network expects to require supply-side augmentation in three years, the demand management alternative must also be available that year.

Two major demand management approaches entail reducing usage at peak periods (peak shaving), or shifting usage to other times of the day when networks are less constrained (load shifting). Also, at constrained parts of the network, distributors might use broad-based load reduction or energy efficiency measures to manage demand. Figure 2 highlights these approaches as 'peak shaving', 'load shifting' and 'broad-based load reduction' (or 'demand improvement'/'energy efficiency').

Figure 2: Demand management approaches



These approaches will typically be implemented at the level of an end-user in practice. Direct load control of air conditioning will have a peak-shaving impact, whereas high-efficiency air conditioners will reduce energy consumption whenever the air conditioner is operating.

3.3 Background to the rule change decision

In its rule change determination, the Australian Energy Market Commission (AEMC) found that amending the Current Scheme would assist in promoting an optimal level of demand management.¹⁴ The AEMC agreed with the rule change proponents that the Current Scheme had not been effective in encouraging an efficient level of demand management. The underlying reasons for the rule change request included:

- It only focussed on cost recovery and did not provide distributors with the opportunity to profit from demand management.¹⁵
- The DMIA provided under the Current Scheme was too small to genuinely encourage experimentation and innovation.¹⁶ Moreover, its uptake was also low.¹⁷ Bearing that in mind, TEC considered the current DMIA's size would be sufficient if we had an effective incentive scheme.¹⁸
- It may have insufficiently incentivised distributors to substitute capital investment with demand management options given the relative risks and characteristics of such projects because it was not a 'true' incentive scheme that allowed distributors to earn rewards where they had delivered defined goals.¹⁹ TEC therefore suggested that we should incentivise demand management based on the actual reduction in electricity demand (particularly peak demand) it brought.²⁰
- Rewards were short relative to the long term returns available on network investment, which could be around 40 years.²¹ As such, the new rule avoided discouraging demand management projects that might incur costs and deliver benefits across multiple regulatory control periods.²²

¹⁴ The AEMC made this determination in 2015, in response to rule change requests by COAG Energy Council and the TEC.

¹⁵ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, p. 4; SCER, *Reform of the DMEGCIS rule change request*, December 2013, p. 4.

¹⁶ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, p. 4; SCER, *Reform of the DMEGCIS rule change request*, December 2013, p. 4.

¹⁷ TEC, *DMIS rule change request: Submission to AEMC*, November 2013, p. 5. Referencing Downes et. al., *Restoring Power: Cutting bills & carbon emissions with Demand Management*, 2013, p. 6.

¹⁸ TEC, *Consultation paper submission*, March 2015, p. 8.

¹⁹ TEC, *DMIS rule change request: Submission to AEMC*, November 2013, p. 5. Referencing AEMC, *Power of Choice*, November 2012, pp. 205–206.

²⁰ TEC, *DMIS rule change request: Submission to AEMC*, November 2013, p. 6. Referencing AER, *Information paper: DMEGCIS*, March 2013, p. 11.

²¹ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, p. 4; SCER, *Reform of the DMEGCIS rule change request*, December 2013, p. 4; TEC, *DMIS rule change request: Submission to AEMC*, November 2013, p. 7.

²² NER, cl 6.6.3(c)(6). This also applies to the allowance mechanism through NER, cl. 6.6.3A(c)(4).

- Distributors were unable to capture benefits from demand management associated with reduced generation capital, as well as reduced opex and avoided investment in the transmission network.²³ Due to this, the rule change proponents proposed allowing distributors to retain a share market benefits that occur at other parts of the supply chain and are attributable to demand management activities.²⁴
- There was uncertainty as to whether we would treat demand management expenditure differently to other expenditure under the rules (for example, whether we could consider demand management expenditure less prudent).²⁵

Keeping the above points in mind, the AEMC also recognised that new distribution pricing arrangements and other regulatory changes would encourage distributors to make efficient expenditure decisions. These reforms had been changing the way distributors engaged with non-network providers, and consider and assess demand management options as efficient alternatives to network investment.²⁶ However, it also considered that, 'it may take some time before these reforms result in efficient demand management being considered and pursued as business as usual'.²⁷ Moreover, the AEMC held the view that distributors' role in managing network demand would likely reduce following the new pricing rules and potential metering competition.

²³ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, p. 4; SCER, *Reform of the DMEGCIS rule change request*, December 2013, p. 4.

²⁴ Specifically, TEC and COAG Energy Council proposed distributors should retain up to 30% and 50% of these net market benefits respectively. See TEC, *DMIS rule change request: Submission to AEMC*, November 2013, p. 7 and SCER, *Reform of the DMEGCIS rule change request*, December 2013, p. 2.

²⁵ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, p. 4; SCER, *Reform of the DMEGCIS rule change request*, December 2013, p. 4.

²⁶ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, pp. 23–25.

²⁷ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, p. 25.

4 Application of the new rule

This section sets out the assessment criteria we will apply in designing a Scheme and Allowance Mechanism that meets their respective objectives. We also discuss the scope of the new Scheme and Allowance Mechanism under the new rules, including with respect to the national ring-fencing guideline.

4.1 Assessment criteria for Scheme options

The most important criterion for a Scheme design option is that it contributes to the achievement of the 'demand management incentive scheme objective' in the rules. That is, it should.²⁸

provide Distribution Network Service Providers with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.

We consider that any option that meets this objective will also reward distributors for implementing relevant non-network options that deliver net cost savings to retail customers.²⁹

Subsequent to an option meeting this criterion, we will apply assessment criteria based around principles in the rules that we must take into account in developing the Scheme.³⁰ Our criteria include:

- The Scheme should balance the incentives between expenditure on network options and non-network options relating to demand management. In doing so, we may take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the market associated with implementing relevant non-network options.
- The level of incentive the Scheme provides should be reasonable considering the long term benefit to retail customers. It should not include costs that are recoverable from another source, including under a relevant distribution determination.
- The Scheme should not impose penalties on distributors.
- The length of a regulatory control period should not limit a Scheme's incentives if this would not contribute to achieving the Scheme's objective.
- The Scheme should have regard to its possible interactions with other incentives for the distributor to invest in and implement relevant non-network options, particular control mechanisms, and meeting regulatory obligations or requirements.

²⁸ NER, cl. 6.6.3(b).

²⁹ NER, c 6.6.3(c)(2).

³⁰ NER, cl. 6.6.3(c).

Subsequent to an option meeting these criteria based on the principles we must have regard to under the rules, we will then consider additional assessment criteria. Table 2 explains the relevance of these criteria in giving effect to the rules.

Table 2: Additional criteria to help give effect to the rules

Additional criteria	Why we consider this is relevant in giving effect to the rules
Enhances competition.	<p>The contestable market may provide non-network options relating to demand management at lower costs than what it would cost distributors to provide non-network options. Facilitating effective competition should be possible in this instance because distributors can generally procure demand management services from third party demand management providers.</p> <p>If so, incentives to enhance competition are likely to promote the Scheme's objective by incentivising distributors to provide demand management options at lower costs than previously. Competition may also result in distributors providing a greater diversity of efficient demand management options. Reductions in the cost of providing efficient demand management options would make these options more affordable and could result in demand management options being supplied to a larger number of customers.</p> <p>We consider that this criterion is also relevant for ensuring consistency between demand management incentives and other regulatory measures that are designed to promote contestable markets where appropriate.</p>
Transparent to apply.	<p>The objective of the Scheme will be promoted by ensuring that it can be implemented in an understandable and transparent manner. Achieving this should increase accountability, by allowing ourselves and stakeholders to verify the costs and impact of the Scheme. In turn, this will assist us in providing a level of incentive that is reasonable considering the long term costs to customers.</p> <p>More generally, a transparent Scheme will assist us to observe whether the Scheme is achieving its objective in incentivising efficient expenditure on relevant non-network options relating to demand management.</p>
Simple and administratively straightforward.	<p>The purpose of this criterion is to reduce the administrative costs of applying the Scheme for us, distributors and third party demand management providers that have the potential to benefit from the Scheme.</p> <p>If the administrative burden of receiving benefits under the Scheme is large, it might fail to incentivise distributors to undertake some efficient expenditure on relevant non-network options relating to demand management, particularly if these options are small relative to the administrative burden. Thus, reducing the administrative burden is likely to promote the Scheme's objective.</p>

It is also worth noting that the level of incentive may vary by distributor and over time under the Scheme.³¹ This recognises that the reward should broadly align with retail customers' willingness to pay for the cost of the Scheme and that we should not reward distributors twice for efficient expenditure on relevant non-network options.³²

4.2 Assessment criteria for Allowance Mechanism options

³¹ NER, cl. 6.6.3(c)(4)(iii).

³² AEMC, *National Electricity Amendment (DMIS) Rule 2015 No. 8*, 20 August 2015, p. 62.

The new rule requiring us to develop an Allowance Mechanism responds to concerns that the current regulatory framework creates a bias towards expenditure on network investment over non-network options. The potential bias arises for a number of reasons, including because distributors may have limited incentives to trial new non-network options.

The most important criterion for the Allowance Mechanism is that it contributes to the achievement of the 'demand management innovation allowance objective' in the rules. That is, it should:³³

provide Distribution Network Service Providers with funding for research and development in demand management projects that have the potential to reduce long term network.

We consider that any design option that meets this objective will also fund projects that have the potential to deliver ongoing reductions in demand or peak demand.³⁴

Subsequent to an option meeting this criterion, we will apply the following assessment criteria based on the principles set out in the rules:³⁵

- The projects the Allowance Mechanism applies to should be innovative and not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.
- It should provide a reasonable level of the allowance considering the long term benefit to retail customers.
- It should only provide funding that is not available from any another source, including under a relevant distribution determination.
- It will require distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance.³⁶ As part of this, we consider it should promote access to demand management research results.

Subsequent to an option meeting these criteria based on the principles we must take into account under the rules, we will then consider additional assessment criteria. Table 3 explains the relevance of these criteria in giving effect to the rules.

Table 3: Additional criteria to help give effect to the rules

Additional criteria	Why we consider this is relevant in giving effect to the rules
Enhances competition.	Given the diversity of third party demand management providers, we expect that promoting competition could significantly increase the scope for innovative R&D projects relating to demand management. By opening up the Allowance Mechanism to a greater range of ideas, this would help give effect to the Allowance Mechanism's objective of providing distributors with funding for R&D in demand management projects

³³ NER, cl. 6.6.3A(b).

³⁴ NER, clause 6.6.3A(c)(2)(i).

³⁵ NER, cl. 6.6.3A(c).

³⁶ NER cl. 6.6 3A(d).

that have the potential to reduce long term network costs.

Transparent to apply.	<p>The objective of the Allowance Mechanism will be promoted by ensuring that it can be implemented in an understandable and transparent manner. Achieving this should increase accountability, by allowing ourselves and stakeholders to verify whether we have provided a reasonable level of the allowance considering the long term benefit to customers.</p> <p>More generally, a transparent Allowance Mechanism will assist us to observe whether it is meeting its objective of providing distributors with funding for R&D in demand management projects that have the potential to reduce long term network costs</p>
Simple and administratively straightforward.	<p>The purpose of this criterion is to reduce the administrative costs of applying the Allowance Mechanism for us, distributors and third party demand management providers that have the potential to directly or indirectly benefit from the Allowance Mechanism.</p> <p>If the administrative burden of receiving funds under the Allowance Mechanism is sufficiently large, distributors might avoid undertaking some R&D in demand management projects that have the potential to reduce long term network costs. As such, this criterion is likely to promote the Allowance Mechanism's objective.</p>

The level of allowance provided under the Allowance Mechanism may vary by distributor and over time.³⁷ This recognises that rewards of the Allowance Mechanism should broadly align with retail customers' willingness to pay for it and we should not reward distributors twice for efficient expenditure on relevant non-network options.³⁸ This also allows us to tailor the level of the allowance to an individual distributor's requirements and circumstances.³⁹

We may use the Allowance Mechanism to fund demand management projects which occur over a period longer than a regulatory control period. All of the potential options we consider in section 7 have this capability.

4.3 Scope of the new rule

Under the new rule, expenditure under the Scheme must be on efficient non-network options relating to demand management. Non-network options:

- Involve non-network assets. These are assets that are not used to convey or control the conveyance of electricity to customers,⁴⁰ and that are not connection assets.⁴¹ For instance, non-network assets might include assets that customers use to reduce their demand for electricity, or assets on which expenditure is undertaken by a third party; or
- Can also include options that involve some expenditure on a network asset, but not expenditure on network assets alone.

³⁷ NER, cl 6.6.3A(c)(3)(iii).

³⁸ AEMC, *National Electricity Amendment (DMIS) Rule 2015 No. 8*, 20 August 2015, p. 62.

³⁹ AEMC, *National Electricity Amendment (DMIS) Rule 2015 No. 8*, 20 August 2015, p. 75.

⁴⁰ We take the view that conveying electricity involves taking, carrying or transporting it from one place to another.

⁴¹ The rules define connection assets as 'those components of a *transmission or distribution system* which are used to provide *connection services*'.

The new rule has a narrower scope than the previous rule that underpinned the Current Scheme. The previous rule allowed incentives for distributors to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way. In contrast, the new rule does not refer to other ways of managing demand for standard control services, and contemplates that the Scheme will only be available for expenditure on non-network options.

To be eligible under the Scheme, a non-network option must also address an identified objective that a distributor would otherwise seek to achieve by investing in network assets.

Table 4 illustrates how our interpretation of this new rule affects how we intend to develop and apply the Scheme. We will carefully consider submissions that propose and seek to justify alternative interpretations and applications of the new rule.

Table 4: Interpretation of new scope for rule clause 6.6.3

New scope: Only applies to non-network options relating to demand management	Previous scope: Also applies to some other (than non-network alternatives) way to manage the expected demand for standard control services
<p>Applies to:</p> <ul style="list-style-type: none"> Assets that customers use to reduce their demand for electricity, or to shift their load. These are unlikely to be assets that convey or control the conveyance of electricity to customers. Assets on which someone other than a network service provider undertakes expenditure, regardless of the use to which those assets are put. These will be non-network options. Therefore, the Scheme could potentially provide incentives for a distributor to encourage expenditure by third parties. Options that involve expenditure on both network and non-network assets. This is because the rules define a non-network option as 'a means by which an identified need can be fully or partly addressed other than by a network option'.⁴² The expenditure would still need to be consistent with, and contribute to, the Scheme's objective in the rules. It would also need to achieve balance between the incentives for expenditure on network options and on non-network options. The asset must also address an objective that the distributor would otherwise seek to achieve by investing in its network. 	<p>Same as under new scope, plus also applied to assets that control the voltage at which electricity is delivered via a distribution network, in circumstances where the voltage required by customers at their premise is already known. These are likely to be considered assets that control the conveyance of electricity to customers.</p> <p>We consider that the following types of projects under the Current Scheme would fall under this category:</p> <ul style="list-style-type: none"> Voltage control projects. Power factor correction projects.

4.4 Ring-fencing and the scope of the new rule

⁴² Also see Australian Energy Markets Commission, *Rules Determination: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, 20 August 2015, page 60.

The national ring-fencing guideline came into effect on 1 December 2016.⁴³ It relates to distribution services, which include services provided by means of or in connection with (that is, association with or in conjunction with) a distribution system. It permits distributors to provide all types of distribution services, but requires them to implement various forms of internal separation between direct control services and other (negotiated and unclassified/unregulated) distribution services.⁴⁴

In considering the ring fencing guideline and the Scheme, it is important to keep in mind that the Scheme's objective focuses on the type of option used to address an identified need. Therefore, this necessarily relates to the type of asset deployed. In contrast, the ring-fencing guideline is concerned with the type of service that a distributor provides. The ring-fencing guideline does not limit distributors to only providing services that wholly or partly require network assets. However, it does constrain distributors on how they should structure themselves to provide non-network services.

The Scheme may offer direct incentives to distributors to undertake expenditure on non-network assets that it will use to provide distribution services, including unclassified (or unregulated) distribution services. The Scheme can also incentivise distributors to undertake expenditure on non-network assets for providing distribution services either from a provider that is an affiliated entity for the purposes of the ring fencing-guideline, or from an independent third party provider.

For example, it would be possible to structure the Scheme to reward a distributor where one of its customers obtains a non-network asset from a third party. If these rewards are sufficiently material, then the Scheme should provide an incentive to the distributor to undertake lawful steps available to it to promote customers to acquire those other assets or services from third parties.

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.

⁴³ AER, *Ring-fencing guideline: Electricity distribution*, November 2016.

⁴⁴ See clauses 3.1 and 4 of AER, *Ring-fencing guideline: Electricity distribution*, November 2016.

5 Demand management incentives and the regulatory framework

The objective of the Scheme is to contribute to providing distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. In designing a Scheme that achieves this, it is valuable to take into account possible interactions between the Scheme and other incentives available to the distributor to invest in and implement relevant non-network options, particular control mechanisms, and meeting regulatory obligations or requirements. This is because, to achieve its objective, the Scheme should supplement the existing framework in a way that enhances its ability to promote efficient outcomes.

This section describes key components of the existing regulatory framework that may affect investments in demand management, as well as potential issues or gaps associated with each of those components. These components include:

- Current incentives to minimise costs
- Potential revenue losses associated with lowering demand
- Incentives to provide high service levels
- Current monetisation of benefits accruing in other parts of the electricity value chain
- Current requirements to provide information
- Requirements to send cost-reflective price signals
- Current cultural and non-market barriers

This analysis underpins the Scheme design mechanisms we present in section 6.

5.1 Current incentives to minimise costs

There are four key mechanisms within the existing regulatory framework that operate to incentivise distributors to choose the least-cost mix of capital and operating inputs to deliver services to consumers. These are:

- the Efficiency Benefit Sharing Scheme (EBSS)
- the Capital Efficiency Sharing Scheme (CESS)
- where applied, the revenue cap form of control
- the regulatory investment test for distribution (RIT-D) requirements under the Planning Framework

The Efficiency Benefit Sharing Scheme

The EBSS provides a continuous incentive for distributors to achieve efficiency gains across the regulatory control period. It also removes a distributor's incentive to inflate opex in the expected base year used to forecast opex for the following regulatory control period. The EBSS is an incremental scheme and works on the assumption that

opex is recurrent. It allows distributors to retain any opex reduction for a total of six years, regardless of when those reductions are reflected in new opex allowances through our revealed cost forecasting approach. Consumers then benefit from lower forecast opex in future regulatory control periods. The combined effect of our revealed cost forecasting approach and the EBSS is that opex efficiency savings or losses are shared approximately 30:70 between the distributors and consumers.⁴⁵

We currently exclude DMIA expenditure from the EBSS because it is not funded through the opex building block.⁴⁶ Before we introduced the CESS, we excluded all demand management expenditure from the EBSS rather than only excluding expenditure under the DMIA. Had we not done this, distributors would have had a stronger incentive to reduce opex than capex, particularly towards the end of the regulatory control period. However, when we introduced the CESS, it was our aim to balance the incentive to reduce opex with the incentive to reduce capex. When the opex and capex incentives are balanced, distributors should have an incentive to undertake efficient demand management.

The Capital Efficiency Sharing Scheme

The CESS provides distributors with the same reward for efficiency savings and same penalty for efficiency losses regardless of the year in which the distributor makes the saving or loss. Under the CESS, distributors retain 30 per cent of underspends or overspends, while consumers retain 70 per cent of these. However, if a distributor's capex overspend was inefficient, ex-post capex reviews mean it will bear 100 per cent of the inefficient overspend.⁴⁷

At our Issues Day workshop in September 2016, some stakeholders raised the concern that the CESS could weaken distributors' incentives to pursue demand management by reducing a distributor's benefits from capex deferrals. All else being equal, we agree that by requiring distributors to share their gains from capex-associated cost reductions, this could impact the power of their incentive to reduce capex costs. However, the EBSS similarly requires distributors to share their gains from opex-associated cost reductions. As such, together, we consider these two incentive schemes should balance distributors' incentives to undertake capex or opex.

The revenue cap form of control

We apply revenue caps to the distributors we regulate (except for ActewAGL). Under this form of price control, we set a maximum on the allowable revenue (MAR) that distributors can recover for each year of the regulatory control period. Distributors forecast sales and set prices so the expected revenue does not exceed the MAR. Any

⁴⁵ AER, *Better regulation fact sheet: Expenditure incentives*, November 2013.

⁴⁶ For example, see AER, *Final decision: United Energy distribution determination 216 to 2020, Attachment 9 — EBSS*, May 2016, p. 13, 7.

⁴⁷ AER, *Better regulation fact sheet: Expenditure incentives*, November 2013.

over-recovery (under-recovery) is deducted from (added to) the MAR in future years through an 'overs and unders' account.

By capping distributor's revenue over the regulatory control period, revenue caps incentivise distributors to increase their profits by reducing costs.⁴⁸ All else being equal, these should incentivise demand management projects that reduce costs, at least in the short run.

The RIT-D under the Planning Framework

The RIT-D is part of the Planning Framework under the rules. The purpose of the RIT-D is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).⁴⁹ Given this, the RIT-D proponent must consider whether each credible option could deliver market benefits, including changes in costs for parties other than the RIT-D proponent due to differences in the timing of new plant, capital costs and operating and maintenance costs.⁵⁰ For clarity, third parties can propose non-network options for the RIT-D proponent to assess.⁵¹ The rules allow parties to dispute conclusions made by the RIT-D proponent, and for us to make a determination on such disputes.⁵²

Since January 2014, distributors should take market benefits associated with non-network options into account when making investment decisions under the RIT-D. To date, only around nine RIT-Ds have been finalised, but one has identified a non-network option as the preferred option.⁵³ There has also been at least one other occasion where a third party proposed a non-network, which the RIT-D proponent subsequently assessed in its draft project assessment report.⁵⁴

The RIT-D only applies to projects where a credible option to augment the distribution network costs at least \$5 million. While it does not currently apply to refurbishment or replacement projects, we have recently requested a rule change to open up the RIT-D to all projects over \$5 million.⁵⁵

5.1.1 Potential issues with incentives to minimise costs

⁴⁸ AER, *Stage 1 Framework and approach: Ausgrid, Endeavour Energy and Essential Energy*, March 2013, Attachment 2.

⁴⁹ NER, cl. 5.17.1(b).

⁵⁰ NER, cl. 5.17.1(c)(4)(iii).

⁵¹ NER, cl. 5.17.4(e)(7), (f)

⁵² NER, cl. 5.17.5.

⁵³ United Energy, *Final project assessment report: Lower Mornington Peninsula supply area*, 25 May 2016.

⁵⁴ SA Power Networks, *Draft project assessment report: Kangaroo Island submarine cable*, 2 November 2016.

⁵⁵ These projects are currently exempt under NER, cl. 5.17.3(a)(5). NER, cl. 5.17.3(a)(2) sets out the \$5 million threshold. For our rule change request, see AER, *Request for rule change – Replacement expenditure planning arrangements*, 30 June 2016.

We have previously expressed the view that both the CESS and EBSS combined will assist in putting capex and opex on an equal footing from a financial perspective.⁵⁶ We have also expressed that revenue caps will incentivise distributors to increase their profits by reducing costs.⁵⁷

Nevertheless, aspects of the regulatory framework may prevent distributors from selecting the most efficient investment options. For instance, many stakeholders have expressed that distributors prefer capex over opex. We note that given the complex nature of any longer-term assessment, it is difficult to draw specific conclusions on exactly whether and why distributors prefer capex over opex.

However, distributors may prefer capex over opex for a number of theoretical reasons. For instance, capex is rolled into the regulatory asset base and receives the allowed rate of return over the life of these assets, which are typically decades long. Given this, if a distributor's allowed rate of return is above its actual cost of capital, this would incentivise it to prefer capex over opex, all else being equal. Conversely, however, if this was below its actual cost of capital, this would incentivise a distributor to prefer opex over capex.

Moreover, capex-based network options provide relatively stable long-term cash flows to investors. Distributors may prefer this over opex-based demand management options if this creates the perception that the financial outcomes of such supply-side options are more certain.⁵⁸ We consider distributors will likely have this preference because the regulatory framework provides security around long-term investments. That is, if we approve capex as efficient ex-ante, but due to inaccurate demand forecasts it is inefficient ex-post, the distributor still receives a return on this investment.

Some stakeholders could consider that the regulatory framework insufficiently incentivises distributors to internalise the longer-term economic benefits of investing in more flexible, demand-side options, which are akin to 'option value' or a 'real option'. Given the range of feasible future supply/demand outcomes, and the ability of different portfolios of options to respond to those range of future outcomes, option value implicitly recognises the trade-off between:

- the value of flexibility (option value), which generally stems from adopting smaller scale, more flexible options, versus
- scale efficiency, which generally stem from adopting larger scale, supply side, options.

⁵⁶ AER, *Explanatory statement: Capital expenditure assessment guideline*, November 2013.

⁵⁷ AER, *Stage 1 Framework and approach: Ausgrid, Endeavour Energy and Essential Energy*, March 2013, Attachment 2.

⁵⁸ Section 5.7 below discusses this topic.

In the context of an electricity supply system, this 'option value' could include (but is not limited to):

- The option to cease a project in the future if demand for the services deviates from expectations due to certain future states eventuating. That is, a distributor can, depending on its contract, cease to purchase demand management services, with no impact on the cost per kW, if for example, latent demand on a constrained part of its network declines.
- The option to commission or augment a project in the future if certain future states eventuate. For example, constructing an asset in such a way as to allow it to be upsized in a modular fashion.
- The option to commission a project quicker (that is, with a shorter lead time) if certain situations transpire. These might include gaining planning approval and acquiring land in advance.

In the context of this Consultation Paper, the most pertinent of the above option values are those related to the probability of certain future supply/demand outcomes occurring. The larger the uncertainty around future supply and demand outcomes, the larger the option value associated with adopting smaller scale, more flexible options for balancing supply and demand for electricity. In most cases, demand management will provide more flexibility than supply-side options.

In this context, a Scheme may improve efficiency if it allows a distributor to capture, as a short term financial benefit, some portion of the longer-term economic benefits that may accrue to its customers from adopting a more flexible, adaptable option for balancing supply and demand for its electricity services. Such an approach may be in the long-term interests of consumers.

5.2 Current potential lost revenue with lower demand

Particular forms of price control can cause distributors to lose revenue from lowering demand. These forms of price control would disincentivise distributors from undertaking demand management. Forms of control that could cause this disincentive include:

- Weighted average price caps (WAPCs), which cap prices based on the weighted average of prices for individual components within a specified basket of services. Under the WAPC, the allowed revenue received from each additional unit sold varies by the actual tariff for that unit. That is, the distributor is subject to volumetric risk, with this risk being a function of the marginal price of the tariff component, and the volume sold of that tariff component. Thus, a WAPC allows distributors to keep any additional profit they make when demand is higher than anticipated, and conversely results in them bearing the loss when the reverse occurs (that is, when outturn demand is lower than had been forecast).
- Average revenue caps, which limits the MAR the distributor can earn per unit of output (for example, maximum average charge per kWh) for the first year of the regulatory period, with this increasing or decreasing in each subsequent year of the period in accordance with the approved price control formula. The distributor can

re-balance its tariffs subject to not breaching certain pre-determined limitations (for example, by rebalancing constraints).

The current regulatory framework addresses this by either applying:

- A form of control that does not create this disincentive, such as a revenue cap. Except for ActewAGL, we currently regulate distributors under revenue caps.
- A mechanism under the Current Scheme (which we call 'Part B') that allows distributors to recover foregone revenue resulting from demand reductions.⁵⁹ We have previously applied Part B to distributors regulated under WAPCs. Since distributors are no longer under WAPCs, we do not currently apply Part B.

5.2.1 Potential issues with the current treatment of lost revenue associated with lower demand

We do not currently apply a mechanism to address the potential disincentives as we apply revenue caps to all distributors except one.⁶⁰ An average revenue cap may disincentivise demand management by linking profits to the actual volumes of electricity distributed. That is, under an average revenue cap, profits increase with sales if the marginal revenue is greater than the marginal cost of providing services. Applying a revenue cap has the benefit of decoupling revenue from demand.

5.3 Current incentives to maintain or improve service levels

The STPIS can financially reward or penalise distributors for exceeding or failing to meet certain performance targets.⁶¹ The STPIS may disincentivise distributors from pursuing demand management options if those options are (or are perceived to be) less reliable than network options and if the distributor is subject to a financial penalty under the STPIS.⁶² This disincentive may be problematic unless genuine reliability issues around particular demand management options means they are less efficient than network options after accounting for the value of customer reliability.

5.3.1 Potential issues with service level incentives

If a demand management option does not provide the response when required, lower levels of service will result. Following from this, a distributor may suffer financial penalties under the STPIS arrangements. In theory, this risk should be passed through

⁵⁹ For a description, see AER, *DMIS: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, April 2009, pp. 9–14.

⁶⁰ Currently, ActewAGL is the only distributor subject to this control mechanism

⁶¹ See AER, *Electricity distribution network service provider: Service target performance incentive scheme*, November 2009.

⁶² Reliability measures under the STPIS are based on: the duration of unplanned sustained interruptions per customer (SAIDI), the number of unplanned sustained interruptions per customer (SAIFI), and the number of momentary interruptions per customer (MAIFI).

to the party best able to mitigate that risk. In the first instance, this is likely to mean that this risk should be borne by distributors, who would face the incentive to either:

- pass this risk onto third party demand management providers via the contractual arrangements that they enter into with those providers, or
- self-insure or purchase insurance against the risk of non-delivery of the demand management solution. This service might be in return for a lower price from the third party demand management provider where the insurance cost does not undermine the value of the demand management option.

On face value, this indicates that the Scheme may not need to provide additional incentives to address the potential inability to meet service levels due to a distributor entering into a demand management arrangement with a counterparty.

However, this presumes that the market for 'insuring' against the non-delivery of the demand management solution exists or is efficient. This may not be the case if:

- Third party demand management providers are unlikely to be able to adequately self-insure against the non-delivery of the demand management solution. For example, this might occur if the expected revenue from providing the solution is small compared to the potential financial penalty under the STPIS of non-delivery; and/or
- The market for external insurance for demand management services is illiquid, or immature; and/or
- The market for aggregation and diversification of risk is limited. For example, this might occur if the aggregator market is unable to effectively create a portfolio of demand management solutions that, when considered collectively, reduces risk levels to sustainable levels; and/or
- Distributors are not prepared, for whatever reason, to self-insure against the risk of non-delivery (even where it is efficient).

If these were considered relevant, then there may be value in excluding a defined number of network interruptions associated with unexpected underperformance of demand management projects when estimating the reliability component under the STPIS.⁶³ If we were to do this, we consider that for an underperformance to be 'unexpected' there would need to be reasonable grounds on which to believe that it occurred despite the distributor's and its third party's reasonable best efforts to ensure the project delivered its forecast level of demand management.

However, it is essential to recognise that if we were to exclude supply interruptions due to non-performance of demand management projects, then this would effectively constitute transferring financial risk from distributors to consumers. This is because

⁶³ These components include unplanned SAIDI, unplanned SAIFI and MAIFI. See AER, *Electricity DNSPs: STPIS*, November 2009, p. 22 for a description.

electricity consumers are the parties eventually funding the demand management options through network charges.

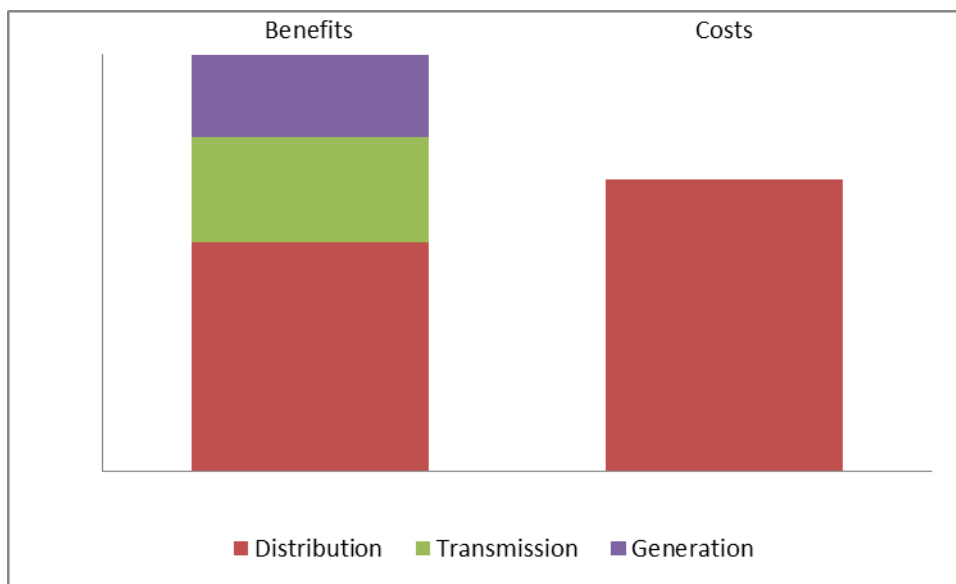
It should also be noted that we are currently reviewing the STPIS in parallel with this review. As such, it may be more appropriate to consider stakeholder submissions on this issue when we amend the STPIS design rather than under the Scheme.

5.4 Monetising benefits accruing in other parts of the value chain

The current regulatory framework allows distributors to internalise benefits that accrue directly to them in the short run from using demand management as a substitute for a network solution. This benefit can result from either a reduction in the cost incurred in the provision of distribution services, or an enhancement in the levels of service provided to end customers.

However, the regulatory framework does not provide a direct means for distributors to monetise the economic benefits of demand management services, where these accrue to other parts of the electricity value chain. Given this, demand management projects such as that illustrated in Figure 3 can arise that are not privately profitable for the distributor but would create benefits across the entire electricity market.

Figure 3: Illustrative example – Costs and benefits of a demand management project



The ring-fencing guideline does not prohibit a distributor's affiliated entity from entering into bi-lateral, non-regulated commercial arrangements with third parties to sell non-distribution services that use the distributor's regulated asset base. While the distributor and its affiliated entity can benefit from such arrangements, these benefits

should be akin to those of two non-affiliated entities partnering. Obligations under the ring-fencing guideline should achieve this by including non-discrimination provisions and requiring the distributor to allocate costs appropriately and have appropriate accounting procedures between itself and its affiliate.⁶⁴

More generally, the regulatory framework already contemplates sharing economic benefits. For instance, the shared asset guideline allows a distributor's customers to share some of the benefits of the distributor selling unregulated services to the market.⁶⁵ Similarly, distributors or their affiliates could enter arrangements with third parties to share the profits of the third party in providing demand management services to other customers of the third party.

Nor, on face value, is there any regulatory or legal barrier to a third party demand management provider selling multiple demand management services to multiple parties across the electricity value chain. For example, a third party demand management provider might provide services to retailers, the transmission business and the distributor. In fact, presumably in a liquid, mature market, any prospective demand management provider would seek to maximise the value generated from its services, having regard to the administrative costs associated with dealing with multiple parties.

5.4.1 Potential issues with the current monetisation of benefits at other parts of the electricity value chain

There may be a barrier to monetising economic benefits accrued at other parts of the electricity value chain. However, even if distributors could monetise these net-market benefits:

- there are still administrative costs associated with doing so, whether undertaken by the third party demand management provider or the distributor (as an agent for the third party demand management provider), and
- the shared asset guideline may, to some degree, affect the incentives for distributors to do so.

An immature and/or illiquid demand management market may exacerbate these issues. If few successful businesses have been built on providing demand management services, it will likely be difficult for new businesses to make up-front investments in systems, processes and the development of internal intellectual property to overcome these perceived barriers. We may consider applying a mechanism under the Scheme to address this by:

⁶⁴ See AER, *Ring-fencing guideline explanatory statement*, November 2016.

⁶⁵ AER, *Better regulation: Shared asset guideline*, November 2013, p. 4; AER, *Ring fencing guideline electricity distribution*, November 2016, p. 10.

- Encouraging commercial arrangements by incentivising joint activities with industry parties in other parts of the value chain and/or the use of third parties (see section 6.3 for an example of this).
- Calculating (and periodically updating) the specific benefits that demand management might be expected to provide to other parts of the value chain, and reflect these as an incentive to the distributor (see section 6.2, for example).
- Using the Scheme to provide an overall uplift in returns from undertaking demand management-related opex to offset inability to monetise some benefits that accrue to other parts of the supply chain (see section 6.1 for an example of this).

5.5 Current information provision requirements

The Planning Framework presently aims to address the information asymmetry between distributors and third party demand management providers. This includes the preparation of the Distribution Annual Planning Report (DAPR), the RIT-D and the development of a demand side engagement strategy. Distributors must describe this strategy in a Demand Side Engagement Document, by setting out how they will engage with non-network providers and consider non-network options.⁶⁶

There will also be a third mechanism from 1 July 2017, with the AEMC introducing further information requirements through the Local Generation Network Credits Rule change. These changes will require distributors to complete a system limitation template setting out:⁶⁷

- the name (or identifier) and location of substations, sub-transmission lines, zone substations and, where appropriate, primary feeders, where there is a system limitation or a projected system limitation during the forward planning period that has been identified in a distributor's DAPR;
- the estimated timing (months(s) and year) of the system limitation or projected system limitation identified;
- the distributor's proposed option to address the system limitation;
- the estimated capital or operating cost of the proposed option; and
- the amount by which peak demand at the location of the system limitation or projected system limitation would need to be reduced in order to defer the proposed network solution, and the dollar value to the distributor of each year of deferral.

In addition, non-network providers may require information on how network elements operate under normal and contingency situations. This information is generally available to network planners, but is seldom available outside the distributors. This

⁶⁶ See NER, cl. 5.13.1(e)–(j).

⁶⁷ See AEMC, *Final rule determination: National Electricity Amendment (Local Generation Network Credits) Rule 2016*, December 2016.

might include information such as response times to faults and technical data such as network element impedances. Third party demand management providers require both technical and non-technical information to enable them to make informed decisions about whether it is commercially viable for them to invest.

5.5.1 Potential issues with current information requirements

At our Issues Day workshop, attendees noted that information asymmetries are one of the biggest barriers to demand side engagement. They suggested potentially useful information would include:

- The geographic locality/boundaries of customers serviced by the constrained part of the network.
- Key assumptions used in forecasting the network constraint.
- Key drivers of events that would lead to network constraint (for example, extreme heat event, increase in production at local plants, use of an irregularly used facility).
- Load profiles and forecast profiles, plus power factors and voltage variations where relevant, for the constrained part of the network, for both an average day and a peak demand day during the month/s and year/s when the network approaches or is constrained.
- A breakdown of customers, by number and tariff/type, by the constrained part of the network.
- Load profiles and forecast profiles for the average customer in each customer type/tariff, for both an average day and a peak demand day during the month/s and year/s when the network approaches or is constrained.
- Research and information on the end-use equipment and energy use by relevant customers, by customer type, if available to the distributor.
- The timing (that is, hours in the day, day of the week and month), length of time and how often that a peak demand reduction would be required in order to defer the proposed network solution.
- The length of time that notice can be provided before load shedding is required, assuming load shedding was the demand management option.

5.6 Requirements to send cost-reflective price signals

Distribution network prices are to move towards reflecting the efficient cost of providing network services to individual consumers. This requires distributors to:⁶⁸

- Base network tariffs on the long run marginal cost of providing the service. This rewards consumers with lower network charges for actions that will reduce future network costs, such as reducing peak demand.

⁶⁸ AEMC, *Distribution Network Pricing Arrangements, Rule Determination*, 27 November 2014, pp. iii–iv.

- Recover their total efficient costs of providing services in a way that minimises distortions to price signals that encourage efficient use of the network by consumers when recovering revenue from each network tariff.
- Consider the impact on consumers of changes in network prices when developing tariffs. Also, develop price structures that consumers can understand. Distributors can gradually phase-in these new price structures.
- Set network tariffs that comply with any jurisdictional pricing obligations.
- As previously, avoid cross-subsidies between different classes of consumers. That is, the level of network prices for a tariff class must be between the avoidable cost of not providing the service and the stand-alone cost of providing the service to the relevant consumers. Also, annual price movements within a tariff class must fall within the existing side constraints.

As part of this, distributors must prepare a Tariff Structure Statement to inform stakeholders of their methodology for determining tariff structures. They must also demonstrate to us how they have consulted with consumers and retailers in developing their price structures.

Complementary to the move towards more cost-reflective pricing, new rules relating to metering contestability aim to facilitate a market-led deployment of advanced meters. This will allow any party to compete to provide metering services to retailers, subject to registration requirements. The rule will also facilitate the commercial provision of services enabled by advanced meters, such as access to voltage and other data in real time.⁶⁹

5.6.1 Potential issues with current price signals

The regulatory framework aims to support moving towards cost-reflective distribution pricing and encouraging efficient demand management. However, it appears to us that the move towards cost-reflective pricing may be gradual. The AEMC also recognised that it will likely take some time to achieve cost-reflective pricing.⁷⁰ Further, the metering contestability rule does not come into effect until 1 December 2017 and its impact will likely be gradual. The AEMC has also noted that the penetration of advanced meters had been low outside of Victoria.⁷¹

Pricing and metering reforms should eventually promote better price signals and more efficient demand management. We do not intend to use the Scheme to incentivise cost-reflective pricing. We anticipate that before these reforms come into full effect, we can use the Scheme to incentivise efficient demand management in other ways.

5.7 Current cultural and other non-market barriers

⁶⁹ See AEMC, *Rule Determination: Expanding competition in metering and related services*, 26 November 2015.

⁷⁰ AEMC, *Rule determination: National electricity amendment (DMIS) rule 2015*, August 2015, pp. 20–21.

⁷¹ See AEMC, *Information sheet: Final rule to increase consumers' access to new services*, November 2015.

The current regulatory framework includes a number of measures that incentivise distributors to employ non-network options where they can balance supply and demand at least cost. These include the EBSS and CESS, as discussed above.

It also includes measures that make distributors consider non-network solutions and publish strategies for doing so with the involvement of third parties. As discussed in section 5.1, the RIT-D and other components of the Planning Framework address this, including preparation of the DAPR, the development of a demand side engagement strategy and its publication in the Demand Side Engagement Document.

5.7.1 Potential issues

Some stakeholders have suggested that there are cultural and other non-market factors that prevent distributors from getting involved in demand management or other non-network solutions. For example, most distributors have significantly more experience and expertise in providing capex-based network options than they do in providing or contracting for demand management options. In addition, the capex-based network options that distributors are accustomed to providing are characterised by very high levels of reliability and automation. In contrast, non-network solutions often require significant levels of operator intervention and may involve technologies with lower levels of operational reliability as compared to traditional network options. Any or all of these factors can contribute to a perception within the network that demand management solutions are relatively risky, unviable or are limited to being reactionary in nature rather than having the potential to be a planning tool. If distributors do not consider demand management options at the planning stage, then there appears to be a large barrier to overcome before distributors will effectively deploy demand management. Gaining real-world experience with non-network solutions can be an important means for overcoming these perceptions and misgivings.

Some jurisdictions have used targets to encourage demand management or other forms of non-network solutions.⁷² These jurisdictions have usually justified targets on the basis that requiring distributors to undertake or produce demand management services will assist in overcoming any cultural or systemic barriers to adopting these approaches. Targets may aim to either maximise the implementation of cost-effective demand management or to ensure the distributor gains and builds on real-world experience.

The risk in setting a target is that the level of the target will be inefficient such it promotes either too little or too much demand management. Of the two, the greater risk is that the level is too high, as it will cause expenditure on demand management that is not cost effective. Mandating a lesser (or even a minimal) amount of demand management implementation could avoid this pitfall and will still ensure the distributor gains experience with demand management and the benefits it can provide. Where

⁷² Following from Queensland Department of Employment, Economic Development and Innovation, *Queensland energy management plan*, May 2011. See Downes et. al., *Restoring Power: Cutting bills & carbon emissions with Demand Management*, 2013, p. 54.

other aspects of the regulatory framework support demand management, this may be sufficient to overcome any cultural biases at play.

Moreover, the information asymmetry between the regulator and the distributor regarding the status of the network and the nature of customers' loads poses potential problems regardless which entity sets the target.

Targets can also focus on demand management in constrained areas, the system as a whole, or some geographic area in between (for example, the various areas served by different bulk supply points). Regardless of the geographic area, we will have to establish methods for adjusting observed results for factors outside of the distributor's control. These could include weather, significant changes in economic conditions, major plant closures or start-ups, significant changes in customers' take-up of energy efficiency measures or distributed energy generation technologies.

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.

6 Potential Scheme design options

In this section, we discuss different mechanisms that we could use in different combinations to form alternative Scheme design options to meet the Scheme's objective and address the barriers that appear to hinder the use of demand management despite the incentives within the regulatory framework.

We have identified a number of mechanisms that could be part of the Scheme design. Table 5 provides an illustrative summary of how an example set of mechanisms directly relate to the perceived problem and/or barriers they would aim to address.

Table 5: Relationship between regulatory framework, perceived problems and possible Scheme mechanisms

Component of the regulatory framework: Perceived problem	Relevant potential Scheme mechanisms
<p>Cost minimisation: Capex preference.</p>	<ul style="list-style-type: none"> Provision of return of and on capex that would have been spent on supply-side option for a period of time. Estimate the option value and use the Scheme to allow distributors to monetise this flexibility benefit. Use the Scheme to provide an overall uplift in returns from undertaking demand management-related opex.
<p>Cost minimisation: Inability to monetise benefits to other parts of the value chain.</p>	<ul style="list-style-type: none"> Encourage commercial arrangements by incentivising joint activities with industry parties in other parts of the value chain and/or the use of third parties. Calculate (and periodically update) the specific benefits that demand management might be expected to provide to other parts of the value chain, and reflect these as an incentive to the distributor. Use the Scheme to provide an overall uplift in returns from undertaking demand management-related opex to offset inability to monetise some benefits that accrue to others in the electricity supply chain.
<p>Delivery of efficient levels of service: Exacerbates distributors' potential bias against demand management if their inexperience with undertaking it creates a perception or realisation of service risk.</p>	<ul style="list-style-type: none"> If appropriate, provide incentive payments for insurance policies. While we may want to explore excluding some network interruptions associated with unexpected underperformance of demand management projects when estimating the reliability component under the STPIS, it may be more appropriate to explore this under our current STPIS review rather than in developing the Scheme.
<p>Information requirements: Information asymmetry and resulting cost impost on third parties.</p>	<ul style="list-style-type: none"> Incentives for additional information provision.
<p>Enhance competition: Lack of engagement with competitive market players.</p>	<ul style="list-style-type: none"> Incentivise the development and publication of case studies. Encourage commercial arrangements by incentivising the use of third parties rather than in-house resources. Incentives for competitive bidding processes.
<p>Other: Cultural barriers.</p>	<ul style="list-style-type: none"> Incentives to meet and exceed targets set by the regulator.

- Incentives to set and meet demand management targets set by the distributor (with the size of the incentive increasing as the target is more ambitious).

We have discretion on how we apply the Scheme to individual distributors. We may find value in applying some mechanisms on an ongoing basis under the Scheme. However, depending on their content and interaction with the existing regulatory framework, it may be appropriate to implement some mechanisms on a temporary basis, such as for one regulatory control period. This could assist distributors to establish the use of demand management, after which transitional arrangements may no longer be necessary.

Different Scheme designs can be constructed by selecting one (or multiple mechanisms where that is deemed necessary) to address each of the problems that we have identified as a barrier to the use of non-network solutions to efficiently balance supply and demand. In the event that one or more of the problems above were determined to be significantly less important, they might not be included in the Scheme, at least initially. On the other hand, for the Scheme to be successful, it will need to include mechanisms for addressing problems that are fundamental to ensuring distributors use non-network solutions where they can provide the most efficient means for balancing supply and demand.

In addition, each option (group of mechanisms) may be considered as the Scheme design will need to be assessed against the Scheme's object and the principles set out in the new rule, as well as our additional criteria, all of which are discussed in section 4.

We are currently in the engagement stage and have not formed a definitive view on our preferred Scheme design option/s. We look forward to receiving submissions on these mechanisms and how they might be combined into different options for the Scheme design. After considering submissions, we propose to outline the options that we see as most promising at our Options Day workshop in the first quarter of 2017.

Following the Options Day workshop, we will put our preferred position forward in our draft Scheme. Our preferred position will seek to combine those mechanisms that will most efficiently address and help overcome those barriers that are having the most impact on distributors' efficient use of non-network solutions.

In the remainder of this section, we discuss four possible groups of mechanisms that could constitute or be part of the overall Scheme design option that would meet the Scheme's objective. The groups of mechanisms address different aspects of the barriers that have been identified and different means for addressing them, as follows:

1. Introduce targeted mechanisms to address specific perceived disincentives.
2. Internalise externalities by applying a net-market benefit sharing mechanism.
3. Incentivise distributors to promote the involvement of third party demand management providers to undertake demand management.
4. Apply demand management targets.

The groupings identified above and discussed in the following paragraphs are illustrative only.

6.1 Type 1: Mechanisms to target potential disincentives

Stakeholders have voiced a number of ways we could develop a Scheme to address potential disincentives for distributors to undertake demand management. We have explained and developed some of these ideas.

We invite submissions on these barriers, as well as the potential mechanisms to address them. We are particularly interested in supporting evidence on the barriers to demand management that various stakeholders have proposed. Such evidence will assist us in developing appropriate mechanisms; particularly given there can be conflicting views in this area.

As outlined in section 5, it may be that parts of the regulatory regime impose specific disincentives on distributors to undertake efficient demand management projects. Given this, we may find value in applying one or a combination of targeted mechanisms to address these specific disincentives. For instance, these could include one or a combination of the following:

- Limiting penalties associated with demand management projects under the STPIS if we consider the STPIS is not balancing incentives as intended. For instance, this might occur if distributors perceive demand management options to be less reliable than network options out of their relative inexperience in providing these options.⁷³ Under such a scenario, we might want to apply a mechanism to address this. For instance, when estimating the reliability component under the STPIS, we could exclude a defined number of network interruptions associated with unexpected underperformances of demand management projects.⁷⁴ For an underperformance to be 'unexpected' it must occur despite the distributor's or its third party's reasonable effort to ensure the project delivered its forecast level of demand management.
- We may want to exclude demand management R&D (that is, projects under the Allowance Mechanism) from the opex building block and therefore the EBSS. This is consistent with how we currently treat DMIA-related expenditure.⁷⁵

⁷³ See AER, *Electricity distribution network service provider: Service target performance incentive scheme*, November 2009. Reliability measures under the STPIS are based on: the duration of unplanned sustained interruptions per customer (SAIDI), the number of unplanned sustained interruptions per customer (SAIFI), and the number of momentary interruptions per customer (MAIFI).

⁷⁴ These components included unplanned SAIDI, unplanned SAIFI and MAIFI. See AER, *Electricity DNSPs: STPIS*, November 2009, p. 22 for a description.

⁷⁵ For example, see AER, *Final decision: United Energy distribution determination 216 to 2020, Attachment 9 — EBSS*, May 2016, p. 13, 7.

- Providing incentives to help place capex and opex on more of an equal footing. As discussed in section 5.1, stakeholders have raised that distributors may have an incentive to favour capex over opex. If we receive convincing evidence to support this view, we may want to apply a mechanism under the Scheme that aims to place opex on a relatively equal footing to capex. Some potential mechanisms might include:
 - Allowing distributors revenue which includes an uplift on the amount spent on a demand management project so that they receive an 'instant return' on their investment. This could be in addition to other rewards that distributors receive from the demand management project lowering its costs. A similar scheme presently operates for transmission businesses under the Network Capability Improvement Incentive Scheme, which encourages transmission businesses to focus on low cost-high value options by providing \$1.5 dollars for every \$1 spent on projects which cost less than \$5 million; or
 - Providing a return equivalent to foregone return on and return of capital over one or two regulatory control periods; or
 - If possible to reasonably estimate, provide distributors with a financial uplift on demand management options proportional to the option value associated with that option (as discussed in section 5.1.1); and
 - As a possible extension, link projects under the Allowance Mechanism to the Scheme. For instance, this might entail allowing for a higher-powered incentive or 'innovation return bonus' if distributors are able to translate their R&D under the Allowance Mechanism to a viable project under the Scheme. We recognise that such a link could motivate distributors to think about R&D more strategically by pursuing Allowance Mechanism projects that have the potential to be marketable or economically viable in the future.
- Extending to ActewAGL the recovery of foregone revenue mechanism under Part B of the Current Scheme. As discussed in section 5.2, we regulate ActewAGL under an average revenue cap.⁷⁶ Applying Part B to ActewAGL might address a disincentive for it to undertake demand management because, under an average revenue cap, profits increase with sales if the marginal revenue is greater than the marginal cost of providing services. Alternatively, we are about to commence the Framework and Approach for ActewAGL and could consider applying a revenue cap.

6.2 Type 2: Net-market benefit sharing

As discussed in section 5.4, distributors will not necessarily be able to monetise benefits that their demand management projects bring to other parts of the electricity

⁷⁶ See AER, *Final decision: ActewAGL distribution determination, Attachment 14 – Control mechanism*, April 2015. An average revenue cap caps the average revenue per unit of electricity sold that a distributor can recover. The cap is calculated by dividing the MAR by a particular unit/s of output, usually kilowatt hours. The distributor sets prices so the average revenue does not exceed the MAR per unit of output.

supply chain. Given this, a potential option may be to introduce an ex-ante net market benefit sharing mechanism to allow distributors to internalise some of the positive externalities that demand management projects can bring. This mechanism could increase distributors' financial valuation of demand management projects with positive externalities such that they undertake more demand management projects that deliver lower overall market costs.⁷⁷

Table 6-6 provides a simple illustrative example of how a net market benefit sharing mechanism might function in practice. In making an investment decision, the best option in net present value (NPV) terms is expected to be deployed after evaluation of the costs and benefits of credible options. Both network and non-network options should be evaluated. The new Scheme allows the consideration of net economic benefits delivered to all those associated with implementing relevant non-network options.⁷⁸

Table 6-6: Example opportunity to share net market benefits

Credible option	NPV distribution benefits less costs (\$ mil)	NPV non-distribution benefits less costs (\$ mil)	NPV total market benefits less costs (\$ mil)
1 Network option	<u>15</u>	0	15
2 Combination of network and non-network option	12	5	17
3 Demand management option	11	9	<u>20</u>

In this illustrative example:

- The distributor prefers Option one if there is no sharing mechanism. This has a NPV to the distributor of \$15 million and no non-distribution benefits. The total market benefit equals the distributor's benefit.
- The consumers prefer Option three as it has an NPV to the total market of \$20 million of which the distributor benefit is \$11 million and non-distribution benefit is \$9.0 million.
- If a net market benefit sharing mechanism allows distributors to keep half (\$4.5 million) of the non-distribution market benefits (\$9.0 million), both the distributor and consumers would prefer Option three. Under this sharing mechanism, distributors would keep $50\% \times \$9 \text{ mil} = \4.5 mil in net market benefits for selecting Option three. This option would be worth $\$11 \text{ mil} + \$4.5 \text{ mil} = \$15.5 \text{ mil}$ to the distributor.

⁷⁷ Australian Energy Market Commission, Power of choice review – giving consumers options in the way they use electricity, final report, AEMC, 30 November 2012, p.209–210.

⁷⁸ NER, cl. 6.6.3(c) (3).

As such, in this example, the net market benefits sharing mechanism results in the distributor choosing Option three over Option one.

While there may be merit in exploring this potential option further, we also understand that market benefits are both difficult to measure and to apportion.

Question 3

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

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?

6.3 Type 3: Mechanisms to promote competition

A potential type of option may be to incentivise distributors to promote the involvement of third party demand management providers to undertake demand management. Mechanisms to promote competition might entail incentivising distributors to provide information or to run a bidding mechanism for non-network solutions.

Incentivise distributors to provide information

As discussed in section 5.5, several mechanisms currently exist (or are about to come into effect) that aim to address the information asymmetry between distributors and third party demand management providers. However, in section 5.1.1, we also noted that these mechanisms may be insufficient for allowing third party demand management providers to genuinely engage in providing non-network options.

To the extent this is true, a further mechanism may include offering an incentive for a distributor to provide this information. That is, under the Scheme, we could provide a financial incentive to the distributor for developing (where necessary) and publishing information in accessible formats and on a schedule that provides sufficient time for third parties to prospect and sign-up demand management resources from end customers.

Bidding mechanism to encourage market delivery

A potential option may entail incentivising distributors to run a bidding process where they award funding to third parties that propose demand management solutions to address network constraints.

Under most scenarios, a distributor will identify an emerging constraint or limitation for the forthcoming five to 10 year period. If the information is released in a manner that allows third party demand management providers to develop business cases, they should be able to 'bid' to deliver a solution to address the underlying need. If such information is not released, it may be worthwhile incentivising distributors to provide information as discussed in the previous section.

The Planning Framework that we apply attempts to facilitate this type of third party involvement. However, due to the administrative costs associated with this, projects under the \$5 million dollar threshold (and currently replacement projects) do not require distributors to follow the RIT-D process, which requires them to consult extensively with third parties and consider non-network options.

Stakeholders raised a number of issues concerning the interaction with the contestable market/third parties. Some specifically asked how best to provide demand management equal access opportunities via the open market. Some suggested that we administer/manage a platform/register for third party providers.

In this context, it may be worthwhile to explore whether we should target the incentives at the network planning stage. This mechanism could entail awarding funds to the distributor to complete the following activities:

- Administer an auction process, including preparing a detailed information package on network constraints and demand management requirements in preparation for the auction.
- Providing an incentive for distributors to develop a standard form contract for demand management that appropriately balances the interests of all parties and clearly identifies the risk and party that is underwriting such risks.
- Administer the ongoing cost of deploying the non-network service.
- Provide funds to the winning bidder.
- Publish the details of the project conducted, including need addressed, solution used and project results.
- Reward the distributor for adopting the non-network solution.

The winning bidder must be the third party demand management provider that proposes a viable solution to deliver the need (for instance, a specified demand reduction) at the lowest cost. We could also consider including projects that are either above or below the \$5 million RIT-D threshold.

6.4 Type 4: Targets for demand management deployment

To drive investments in non-network options, a potential option might be to implement a target-based scheme. Under this potential option, a distributor would receive rewards if it achieves pre-determined non-network targets based on identified constraints at the planning stage. Depending on the available information about the future constraint, the targets could be set across the network at each transmission-to-distribution connection point or distribution feeder connection.

Under this arrangement, we would need to baseline peak demand targets. We would make annual adjustments for weather, energy efficiency and major plant closures to ensure that the reductions have been the result of active demand management by the distributor. These adjustments would be agreed when we make our distribution determination.

Rather than assessing individual projects, the distributor would demonstrate that it has achieved these targets via its annual compliance reporting process. To show non-network options, we would look for third party contractual information. Table 7 shows an example of how a reward-only target-based scheme might operate. In this example, the distributor will only receive a financial reward once it achieves a peak demand reduction of 5 megawatts (MW). Below that threshold, it would not receive any financial reward. If it exceeds 10 MW, it would receive an additional reward.

Table 7: Reward-only target-based scheme by connection point

Annual Financial Incentive	Annual Peak Demand Reduction at connection point
\$0	< 5 MW
\$2 million	5 MW – 10 MW
\$4 million	> 10 MW

Table 8 shows an example of a target-based scheme that allows for penalties when distributors do not engage in demand management. Under this example, it would only receive a financial return if it met a higher threshold. We do not consider this example would be likely because one of the principles we are to take into account under the rules when developing the Scheme is that it should not impose penalties on distributors.⁷⁹ Nevertheless, we considered we should show stakeholders how such an example might operate for completeness.

Table 8: Target-based scheme by connection point

Annual Financial Incentive	Annual Peak Demand Reduction at connection point
- \$4 million	< 5 MW
\$0	5 MW – 10 MW
\$4 million	> 10 MW

⁷⁹ NER, cl. 6.6.3(c).

Table 9 shows an alternative to the connection point approach. This example shows how we might apply a target-based scheme across the entire network. Under this example, we would enable distributors to target areas that might benefit more from demand management than others, such as smaller connection points where it may not be possible to achieve the reductions.

Table 9: Reward only target-based scheme across a network

Annual Financial Incentive per connection point	Annual Peak Demand Reduction across network
\$0	< 50 MW
\$20 million	50 MW – 100 MW
\$40 million	> 100 MW

6.5 Compliance and reporting under the Scheme

Under any of the mechanism types 1, 2 or 3, the distributor will need to either prove the pre-project situation, or to prove they have provided pre-project data and information to third parties. For mechanism type 4, the data concerns improvements to the entire network which requires proving the preceding situation. The exact nature of the data required from the distributor will vary with the mechanism type. Table 10 briefly describes these 'pre-project data requirements'.

Reporting on any Scheme project implemented would vary with the nature of the type of mechanism implemented. Nevertheless, as Table 10 demonstrates, all mechanisms will involve additional 'post-project reporting' requirements. The extent of reporting and amount of data to be supplied will vary with the complexity of the mechanisms, but in each case the information must be sufficient to verify what project/activity was undertaken and to quantify its effects, before incentives are approved.

Table 10: Reporting requirements under different options

Mechanism type	Pre-project Data Requirements	Post-project Reporting
Type 1: Targeted mechanisms to address potential disincentives	Collect and provide the data to demonstrate the pre-project situation, to allow for measuring the project's impact. This includes documenting pre-project forecasts.	Provide a report containing details of the project design and execution, and data on its effects, which are sufficient to understand and quantify the project impacts. Provide data on project costs and revenue impacts. Where relevant, submit an exclusion application for the relevant scheme.
Type 2: Net-market benefit sharing	Collect and provide the data to demonstrate the pre-project situation and enable measuring the total market impact of the project. Document pre-project forecasts of network usage, load profiles and energy costs with and without the demand management project (or versus network augmentation).	Provide a report containing details of the project design and execution, and data on its effects, which are sufficient to understand and quantify the project impacts. Provide data on project costs, network usage and energy cost impacts. Submit an application for net-market benefit sharing incorporating above information.
Type 3: Promote third parties	The distributor would need to provide third parties with detailed information on the relevant network constraints, costs and	Incentivising the provision of information would require reporting on the information provided as well as when, how and to whom the distributor

timing of network solutions, load profiles, customers and other information listed in section 6.3.

communicated the information.

A bidding mechanism would require the above reporting, plus reporting the details of how it conducted the bidding, the results and a report on the project implemented and its effects.

Submit an application for the relevant scheme incentive.

Type 4: Target based scheme

Collect and provide data on current and forecast network demand at connection point or on whole of network, depending on option. Clearly identify the emerging constraint. Provide detailed explanation of forecast basis and anticipated impacts of adjustments for weather, energy efficiency and major plant closures.

Provide a report on the distributor's implemented network demand improvements, with their effects quantified and contractual information. Report the post-improvement network demand at connection point or on whole of network. Provide data for all variables assumed to impact on demand (for example, major weather events). Report network demand adjusted for these variables.

Submit an application for the relevant incentive.

Question 5

How might we best combine the mechanisms discussed in section 6 above into an option that achieves the Scheme's objective?

If you prefer a mechanism that we did not discuss in section 6, please provide details on this mechanism.

Question 6

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

Question 7

How we might best give effect to or enhance the information and reporting requirements discussed in section 6.5 above?

7 Allowance Mechanism design options

We have identified four broad Allowance Mechanism design options that we consider may meet the Allowance Mechanism's objective. These include:

- Minor extension to the status quo.
- High cap allowance with ex-ante approval.
- Bidding to encourage 'ground breaking' R&D.
- Bidding to encourage market-facilitated R&D.

We look forward to receiving submissions on these options and discussing these further with you at our Options Day workshop in the first quarter of 2017. Following the Options Day workshop, we will put our preferred position forward in our draft Allowance Mechanism.

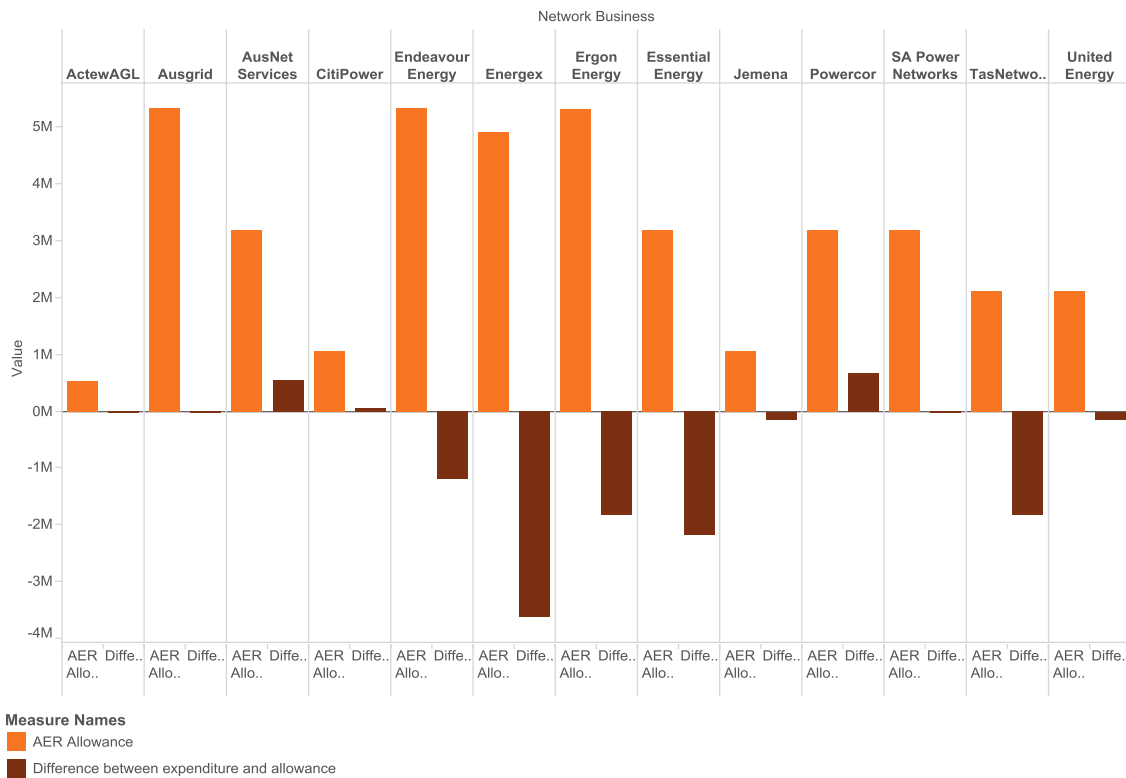
7.1 Option 1: Minor extension to the status quo

The Current Scheme includes the DMIA under Part A, which the new rule treats as the Allowance Mechanism. We currently incorporate DMIA into each distributor's revenue allowance each year of the regulatory control period ex-ante. Its size varies between distributors, and has ranged from between \$0.1–1.0 million. Distributors prepare annual reports on their expenditure under the DMIA in the previous year, which we assess against specific criteria. We then return any underspend against the allowance to customers.

As discussed in Appendix A and shown in Figure 5, distributors have had different appetites for utilising funding under the DMIA.⁸⁰

⁸⁰ Since the DMIA commenced three distributors exceeded their allowance, three spent their allowance and seven underspent. While the size of the overspend did not exceed \$1 million, the level of under expenditure ranged from \$1 million to almost \$4 million.

Figure 4 Comparison of expenditure with allowance



If stakeholders are satisfied with how Part A of the Current Scheme is operating, then a potential option may be to apply an Allowance Mechanism that is similar to the current DMIA. We recognise that some stakeholders may consider there are limitations to the current DMIA, particularly because a number of distributors have underutilised it (see Appendix A or Figure 4). Nevertheless, we also understand that when combined with the new Scheme and other complementary reforms such a metering contestability and cost-reflective pricing, there may be merit in continuing with a modest innovation allowance.

If we were to prefer this potential option, we still consider there may be merit in making the following minor extensions to the current DMIA:

- Requiring distributors to report a specified level of information on demand management projects that receive the innovation allowance. This will increase the information on demand management available to the industry as a whole. While distributors currently provide compliance reports under the DMIA, the quality of information provided under these reports varies considerably between individual distributors.
- Indexing distributors' innovation allowance by the Consumer Price Index each year.
- Re-writing the assessment criteria to improve clarity and to more closely reflect the objective and principles under the new rules

As an example for the third extension, we expect there would be value in emphasising that tariff trials benefiting from the Allowance Mechanism must be innovative. We appreciate that some stakeholders have expressed the view that 'innovative', in the

context of tariff trials might be a subjective concept. For instance, it has been raised that duplicative trials may still be innovative if they are conducted on a new market segment, or if they have never been applied by that distributor previously. As such, we expect that providing additional guidance in our assessment criteria would improve clarity. For instance, we might specify that an innovative tariff trial could occur where:

- The nature of the demand management tariff being trialled significantly differs from other tariffs previously researched or in use in the Australian energy market; or
- The trial focuses on customers in a market segment that significantly differs in either a relevant demographic characteristic, climate zone, or energy end-use characteristic from other market segments where responses to tariffs are known (for example, low income householders versus wider residential population, households with gas versus electric heating); and
- The tariff trial runs for a limited period.

Table 11: Allowance Mechanism option 1 assessment against framework

Objective/principles/criteria	Will it likely meet the objective/principles/criteria?
<p>Objective: Provides distributors with funding for R&D demand management projects that have the potential to reduce long term network costs. We consider that any option that meets this objective will subsequently fund projects have the potential to deliver ongoing reductions in demand or peak demand.</p>	<p>Most likely. To the extent that a modest amount of funding is insufficient to fund R&D with the potential to reduce long-term network costs by delivering ongoing reductions in demand or peak demand, this might fall short of the objective.</p>
<p>Additional principle: Applies to projects that are innovative and not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.</p>	<p>Most likely. Yes, if the AER is willing to remove funding ex-post for projects that fall short of this principle. If the AER sets clear and appropriate criteria for what projects are innovative, this option will likely satisfy this principle.</p>
<p>Additional principle: Level of allowance is reasonable considering the long term benefit to retail customers.</p>	<p>Most likely. Some retail customers might value providing no or a high R&D allowance. However, providing a modest allowance might be a 'safer' option if there are divergent views on what is a 'reasonable' level of allowance.</p>
<p>Additional principle: Only provides funding that is not available from any another source, including under a relevant distribution determination.</p>	<p>Yes. Since this criterion is reasonably objective, there is no reason why the AER would not be willing to remove funding ex-post for projects that fall short of this principle.</p>
<p>Additional principle: Requires distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance. This should be in such a way that it promotes access to demand management research results.</p>	<p>Yes, we can meet this principle under any Allowance Mechanism we apply. See section 7.5 for details.</p>
<p>Additional criterion: All else being equal, we can apply the option to enhance competition.</p>	<p>No.</p>
<p>Additional criterion: All else being equal, we can apply the option transparently.</p>	<p>Yes.</p>
<p>Additional criterion: All else being equal, it can be simple and administratively straightforward to apply.</p>	<p>Yes on face value. But potentially complex and administratively burdensome in light of the modest size of the allowance.</p>

7.2 Option 2: High cap allowance with ex-ante approval

A potential option is to have a high cap allowance mechanism. For instance, we might consider capping this at:

- A proportion of the MAR. For example, if we capped this at one per cent of MAR, this would allow distributors to spend from up to \$6 million (for the smallest distributor, ActewAGL) to \$66 million (for the largest distributor, Ausgrid) on demand management innovation annually.
- A proportion of the distributor's capex program. This would better represent the cost that demand management could potentially alleviate and therefore better reflect its potential benefit. As an example, if we capped this at 10 per cent of the capex program, this would allow ActewAGL to spend up to about \$6 million on demand management innovation annually and Ausgrid to spend up to about \$64 million.⁸¹

If we were to apply such a potential option, we consider it would be important to provide ex-ante rather than ex-post approval. We would not necessarily expect distributors to utilise all the funding we make available to them. This avoids restricting distributors from pursuing ground-breaking (yet costly) R&D projects.

Under an ex-ante approval process, distributors could propose projects under the Allowance Mechanism in their regulatory proposals so both stakeholders and we can assess the merits of these. We consider ex-ante approval would be necessary under this potential option to reduce the risk to the distributor (to avoid spending a large sum of money that they are unable to recover) and the customers (to avoid providing a large amount of funding on R&D that they see little value in supporting).

To assist distributors in preparing their R&D proposals, we would assess proposals against the principles and objective in the rules. We would also provide a guidance to clarify how we intend to interpret and apply the rules, such as how we are to determine whether a particular project is 'innovative' or has the 'potential to deliver ongoing reductions in demand or peak demand'.⁸² For clarity, the ex-ante approval would be contingent of distributors publishing the results of their R&D and for spending their allowance as proposed.

Given the potential size of projects under a high-cap Allowance Mechanism, we may also want to consider including an adjustment to compensate customers for the benefits that accrue to the distributor undertaking the trial.⁸³ This kind of adjustment might be important for avoiding double-dipping due to the distributor receiving both an

⁸¹ Calculations based on table 6-1 of AER, *Ausgrid final decision 2015–19: Attachment 6—Capital expenditure*, April 2015 and AER, *ActewAGL final decision 2015–19: Attachment 6—Capital expenditure*, April 2015.

⁸² NER cl. 6.6.3A(c)(2).

⁸³ As an example, it may be that a side-benefit of the R&D project was that the distributor curtailed 1 kW of peak demand. If this provided the distributor with a benefit of \$150 / kW, it may be preferable for the distributor to pass this onto consumers.

R&D allowance and retaining the capex savings associated with its R&D project for five years under the CESS.

Table 12: Allowance Mechanism option 2 assessment against framework

Objective/principles/criteria	Will it likely meet the objective/principles/criteria?
<p>Objective: Provides distributors with funding for R&D demand management projects that have the potential to reduce long term network costs. We consider that any option that meets this objective will subsequently fund projects have the potential to deliver ongoing reductions in demand or peak demand.</p>	<p>Yes. We can assess against the objective and related principle when we decide what projects to allocate funding towards.</p>
<p>Additional principle: Applies to projects that are innovative and not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.</p>	<p>Yes, we can assess against this principle when we decide what projects to allocate funding towards.</p>
<p>Additional principle: Level of allowance is reasonable considering the long term benefit to retail customers.</p>	<p>Most likely. Since we would approve the allowance ex-ante via the reset process, stakeholders could lodge submissions on the level of allowance requested for particular R&D projects. However, not all consumer representatives share the same views and some retail customers might consider the allowance we approve to be unreasonably high.</p>
<p>Additional principle: Only provides funding that is not available from any another source, including under a relevant distribution determination.</p>	<p>Yes, we can assess against this principle when we decide what projects to allocate funding towards.</p>
<p>Additional principle: Requires distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance. This should be in such a way that it promotes access to demand management research results.</p>	<p>Yes, we can meet this principle under any Allowance Mechanism we apply. See section 7.5 for details.</p>
<p>Additional criterion: All else being equal, we can apply the option to enhance competition.</p>	<p>No.</p>
<p>Additional criterion: All else being equal, we can apply the option transparently.</p>	<p>Yes, particularly transparent as we would approve project funding via the regulatory reset process, which facilitates stakeholder consultation.</p>
<p>Additional criterion: All else being equal, it can be simple and administratively straightforward to apply.</p>	<p>Yes.</p>

7.3 Option 3: Bidding to encourage 'ground breaking' R&D

A potential option may be to construct a bidding mechanism where we award project funding via competitive tender to encourage distributors to deliver ground-breaking R&D projects. Demand management R&D projects that receive the funding may be:

- Proposed and undertaken by a distributor where allowed under the ring-fencing guideline. However, to facilitate maximum knowledge sharing, the distributor must partner with at least one third party in implementing the project. For clarity, a third party would likely (but not necessarily) be a demand management provider or a university.

- Proposed by a distributor that then engages a third party to completely conduct/administer the project on their behalf.
- Proposed by a third party with a view to reduce the long term costs of a distribution network. Since the rules require we provide funding under the Allowance Mechanism to distributors, third parties should partner with a distributor when proposing R&D projects.

Under this potential option, distributors (and third parties) could compete against each other for a portion of a 'pool' of funding to develop and implement innovative projects. We consider a reasonable size of the pool could reflect 0.1 per cent of distributors' maximum allowed revenues, which Table 13 shows.

Table 13: Aggregate of annual funding available

Year applicable from	Aggregate 0.1% of current maximum allowed revenue (\$mil)	Applicable distributors
July 2019	3.75	ActewAGL , Ausgrid, Endeavour Energy, Essential Energy, NT Power and Water
July 2020	7.42	As above plus: Energex, Ergon Energy, SA Power Networks, TasNetworks
January 2021	9.66	As above plus: AusNet Services, Powercor, United Energy, CitiPower , Jemena

This funding can be recovered from each distributor's customers, but only the winner/s receive the funding.⁸⁴

Under this potential option, the Allowance Mechanism could operate as follows:

- We provide each distributor with opex valued at 0.1 per cent of its maximum allowed revenue attributed to the 'Allowance Mechanism'. This recovered revenue goes to an 'Allowance Mechanism Fund'.
- We will hold an annual 'bidding process' subject to funding from the pool shown in Table 13 being available (since projects and funding may span multiple years, it is possible for funding to have already been allocated). During the bidding process, distributors and third parties can submit their project ideas.
- All information from the project, as defined by the minimum project information disclosure requirements that we will define will be shared via a publicly accessible portal and via public forums.

Alternatively, we could set a fixed amount that distributors could bid for, say \$10 million. We could award projects that have been assessed as high value to consumers within that capped allowance and the successful distributors can recover their

⁸⁴ We will further consider whether this approach is available to us under the scope of the tools that we have under the rules.

allowance from their customers. This allows for competitive pressure whilst preventing energy consumers from funding projects that occur outside of their distribution network.

Table 14: Allowance Mechanism option 3 assessment against framework

Objective/principles/criteria	Will it likely meet the objective/principles/criteria?
<p>Objective: Provides distributors with funding for R&D demand management projects that have the potential to reduce long term network costs. We consider that any option that meets this objective will subsequently fund projects have the potential to deliver ongoing reductions in demand or peak demand.</p>	<p>Yes. This can be a project assessment criterion. If no project bid met this, we would not award funding.</p>
<p>Additional principle: Applies to projects that are innovative and not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.</p>	<p>Yes, this would be an assessment criterion. If no project bid met this, we would not award funding.</p>
<p>Additional principle: Level of allowance is reasonable considering the long term benefit to retail customers.</p>	<p>Most likely. Although, some retail customers might dispute this if they contribute funding that its distributor does not receive. However, all retail consumers might benefit due to the publication of results increasing industry knowledge.</p>
<p>Additional principle: Only provides funding that is not available from any another source, including under a relevant distribution determination.</p>	<p>Yes, this would be an assessment criterion. If no project bid met this, we would not award funding.</p>
<p>Additional principle: Requires distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance. This should be in such a way that it promotes access to demand management research results.</p>	<p>Yes, we can meet this principle under any Allowance Mechanism we apply. See section 7.5for details.</p>
<p>Additional criterion: All else being equal, we can apply the option to enhance competition.</p>	<p>Yes.</p>
<p>Additional criterion: All else being equal, we can apply the option transparently.</p>	<p>Most likely, if constructed carefully. A bidding process should provide transparency in theory.</p>
<p>Additional criterion: All else being equal, it can be simple and administratively straightforward to apply.</p>	<p>Probably not. Awarding funding will likely require a difficult exercise of discretion as it is difficult to apply objective criteria to R&D proposals. This has the potential to become easier with time as the process becomes more established.</p>

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

A potential option may entail incentivising distributors to run a bidding process where they award funding to third parties that propose innovative R&D projects. These third parties might include demand management providers, energy retailers, research institutes or others. By requiring R&D projects to be proposed and run by third parties, this Allowance Mechanism aims to capitalise on the profit-seeking innovation of the competitive market.

Under this option, we would provide funding to distributors associated with the following activities:

- Administering the auction process, which they can base around real-world problems that demand management could potentially address. Distributors will award funds.
- Providing funds to the winning bidder to run the R&D project, which will be awarded based on the potential size of the problem to be solved (some funding could be sequestered for geographically-specific problems). The distributor will also assist the third party by providing it with the customer base on which the R&D could be tested.
- Publishing the results of the R&D project, including the implications of these results. The published project results should provide a level of detail to allow other parties to use the results. That is, both the distributor and third party must 'share' the intellectual property that comes out of the project.
- Where applicable, collaborating with the third party to develop a business case for a non-network option based on the research results. This recognises that while there is a role for straight technology research, business model and implementation testing are also important.

Given the distributor must outsource these projects and share the resulting intellectual property, it should be eligible for incentive payments under the option.

We consider that such an option could operate similarly to the Scheme bidding mechanism outlined under section 6.3. However, this would differ in that the location selected for the R&D should not be facing a need for augmentation. This would avoid undermining network reliability by testing unproven solutions when there is an identified need. This location, however, should have the type of customer base or other characteristic that characterises the problem situation.

There are multiple ways to fund this option. A potential option may be to set a fixed amount that distributors could claim per regulatory control period (for example, \$10 million each). However, we are open to other suggestions (such as those used under other Allowance Mechanism options) and welcome submissions on this.

Table 14 shows a high-level assessment of this Allowance Mechanism option against our assessment framework.

Table 15: Allowance Mechanism option 4 assessment against framework

Objective/principles/criteria	Will it likely meet the objective/principles/criteria?
<p>Objective: Provides distributors with funding for R&D demand management projects that have the potential to reduce long term network costs. We consider that any option that meets this objective will subsequently fund projects have the potential to deliver ongoing reductions in demand or peak demand.</p>	<p>Yes. We can require distributors to apply this criterion when assessing whether to award funding to a third party's proposed R&D project.</p>
<p>Additional principle: Applies to projects that are innovative and not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.</p>	<p>Yes. We can require distributors to apply this criterion when assessing whether to award funding to a third party's proposed R&D project.</p>
<p>Additional principle: Level of allowance is reasonable</p>	<p>Most likely. We will determine an appropriate level of</p>

considering the long term benefit to retail customers.

allowance throughout our consultation process so that stakeholders consider it broadly reasonable considering the long term benefit to retail customers. Since this Allowance Mechanism should increase the ability of the distributor, third party and broader industry to provide successful demand management projects, we consider this will likely have substantial long-term benefits to retail customers.

Additional principle: Only provides funding that is not available from any another source, including under a relevant distribution determination.

Yes. We can require distributors to apply this criterion when assessing whether to award funding to a third party's proposed R&D project.

Additional principle: Requires distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance. This should be in such a way that it promotes access to demand management research results.

Yes, we can meet this principle under any Allowance Mechanism we apply. See section 7.5.

Additional criterion: All else being equal, we can apply the option to enhance competition.

Yes.

Additional criterion: All else being equal, we can apply the option transparently.

Potentially. Bidding mechanisms should theoretically increase transparency. However, since distributors award funding, this might reduce transparency.

Additional criterion: All else being equal, it can be simple and administratively straightforward to apply.

Most likely. Outsourcing the awarding of funding to the distributors makes the Allowance Mechanism relatively simple and administratively straightforward for us.

7.5 Proposed information and data requirements

Compared to the current DMIA reporting requirements, we consider the reporting requirements under the new Allowance Mechanism should:

- Be more prescriptive regarding what information and rationale are required to both explain and justify a project.
- Have compliance criteria that more clearly align with the project elements to reduce duplication in reporting.
- Exclude the project categorising criteria to streamline both the project reporting and approval process.
- Reflect criteria consistent with the objective and principles under the new rule.

As an example of potentially improved project approval criteria, the Allowance Mechanism could apply to demand management projects or programs that:

- Are measures undertaken by a distributor to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, rather than increasing supply through network augmentation.
- Are to be innovative and not be otherwise efficient and prudent non-network options that a distributors should have provided for in its regulatory proposal. Innovative projects and programs are designed to explore new potentially efficient demand management mechanisms or technologies, or to explore the application of established mechanisms or technologies in situations where different network or

customer characteristics are likely to impact on the on demand management approach.

- Should be funded to support R&D in demand management projects that have the potential to reduce long term network costs, and the level of the funding should be reasonable considering the long term benefit to retail customers.
- Are adequately documented, with documentation and the level of details reported being proportional to the cost of the project. Documentation will include:
 - Pre-project implementation plans supplied to AER: A project overview, aims and expectations, proposed methodology and design, and implementation plans. Project plans will specify if this is broad-based or a peak demand project focused on a network constraint, a tariff or non-tariff project, and involving opex or capex.
 - Post-project implementation report produced and published: A project overview, aims and expectations, methodology and design, implementation approach, results, conclusions and findings must be publically reported in a research report that describes the project aims, methodology, analysis, results, conclusions and any identifiable benefits. The report must be published to be publically available.
- Receive an allowance to recover costs that:
 - Must not be recoverable under any other jurisdictional incentive scheme.
 - Must not be recoverable under any other Commonwealth or State/Territory Government scheme.
 - Must not be included in forecast capex or opex approved in the distribution determination for the regulatory control period under which the Allowance Mechanism applies, or under any other incentive scheme in that determination.

Using these revised criteria, we could develop a matrix of project explanation elements and criteria such as that in Table 16. We could use this to guide distributors in their reporting on their projects under the Allowance Mechanism.

Table 16: Suggested matrix of project elements and criteria

Explanation Element	Criteria
(a) the nature and scope of each project or program	#1 Demand management project or program #2 Innovative project or program
(b) the aims and expectations of each project or program	
(d) how each project or program was/is to be implemented	#2 Innovative project or program (if innovative in execution rather than nature or scope)
a), b) and d) collectively	#4 a) Pre-project implementation plans
(c) the process by which each project or program was selected, including the business case for the project and consideration of any alternatives	#3 Appropriate funding

(e) the implementation costs of the project or program and

#5 Projects or programs costs recovered under the DMIS

(f) any identifiable benefits that have arisen from the project or program, including any off peak or peak demand reductions.

#4 b) Post-project implementation report

Question 8

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.

Question 9

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

Question 10

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

A Appendix: Assessment of Current Scheme

The Current Scheme has been in place since 2008–09 and has applied to all distributors in the NEM. The Current Scheme contains an innovation allowance called the DMIA or 'Part A'. The Current Scheme also includes a second element that we do not apply (known as 'Part B').⁸⁵ This allows distributors to recover foregone revenue resulting from demand reductions caused by projects under the Current Scheme. We do not currently apply Part B because we originally designed it to address a disincentive caused by a control mechanism (weighted average price caps) that we no longer apply to distributors.⁸⁶

Overall, we consider that the Current Scheme has not been effective in encouraging an efficient level of demand management activity. The total sums we have allocated under the Current Scheme have been modest compared to the total revenue and capex allowances for the distributors. Half of the distributors eligible for the DMIA have not claimed their full allocation. A distributor underspending its full DMIA allocation is not necessarily problematic to the extent that it still channelled sufficient resources into demand management R&D to enhance industry knowledge of practical demand management projects. However, it is not clear that this was the case.

A.1 What have we approved?

We have approved around 40 million of DMIA to projects since the Current Scheme commenced. Table 17 shows, the allowance we offer under the DMIA relative to distributors' maximum allowed revenues.

Table 17: Allowance provided under the DMIA

Distributor	Allowance per annum (\$ million) *	Proportion of maximum allowed revenue (rounded to 3 decimal places) (%) **
Ausgrid	1.0	0.076
Energex	1.0	0.076
Ergon Energy	1.0	0.079
AusNet Services	0.6	0.096
Endeavour Energy	0.6	0.094
Essential Energy	0.6	0.078
Powercor	0.6	0.094

⁸⁵ For a description, see AER, *DMIS: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, April 2009, pp. 9–14.

⁸⁶ This is because the distributors we regulate (except for ActewAGL, which is under an average revenue cap) are under revenue caps which should not penalise demand reductions.

SA Power Networks	0.6	0.078
TasNetworks	0.4	0.125
United Energy	0.4	0.095
CitiPower	0.2	0.067
Jemena	0.2	0.077
ActewAGL	0.1	0.068

Source: Figures from recent AER final decisions; including the overview (for maximum allowed revenue) and the demand management incentive scheme attachment.

* This is provided in \$2015 for the Victorian distributors and \$2014–15 for non-Victorian distributors.

** Calculated as $\text{Annual DMIA} / \left(\frac{\text{MAR}}{\text{Years in regulatory period}} \right)$.

Distributors have also received allowances for demand management activities via our regulatory determinations where we found this expenditure to be efficient and prudent. Moreover, it is possible for distributors' demand management activities to have also been funded outside of the regulatory regime that we oversee. This often occurred in Queensland, where the state government had a significant demand management program.⁸⁷ R&D grants can also come from sources such as the Australian Renewable Energy Agency (ARENA).⁸⁸ That is, our Current Scheme is not the only option by which distributors can fund demand management.

Under Part A, we incorporate the DMIA into each distributor's revenue allowance for opex each year of the regulatory control period ex-ante. Distributors then prepare annual reports on their expenditure under the DMIA in the previous year, which we assess against specific criteria. We then return any underspend against the allowance to customers. The assessment criteria include:⁸⁹

1. Demand management projects or programs are measures undertaken by a distributor to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation.
2. Demand management projects or programs may be:
 - (a) Broad-based demand management projects or programs — which aim to reduce demand for standard control services across a distributor's network, rather than at a specific point in the network. These may be projects targeted at particular network users, such as residential or commercial customers, and may include energy efficiency programs; and/or

⁸⁷ See Queensland Government, *ClimateQ: towards a greener Queensland*, July 2009, p. 95.

⁸⁸ For example, Ergon Energy received ARENA funding to trial a residential solar PV and battery model. See <http://arena.gov.au/project/trialing-a-new-residential-solar-pv-and-battery-model/>.

⁸⁹ These criteria are set out in AER, *Demand management incentive scheme: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, April 2009, p. 5.

- (b) Peak demand management projects or programs — which aim to address specific network constraints by reducing demand on the network at the location and time of the constraint.
3. Demand management projects or programs may be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts.
4. Recoverable projects and programs may be tariff or non-tariff based.
5. Costs recovered under this scheme:
 - (a) must not be recoverable under any other jurisdictional incentive scheme;
 - (b) must not be recoverable under any other state or Australian Government scheme; and
 - (c) must not be included in forecast capex or opex approved in the distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.
6. Expenditure under the DMIA can be in the nature of capex or opex.

If a distributor has not spent its DMIA allowance in the regulatory control period, it will be required to return the amount of any underspend or unapproved amounts to customers in the form of tariff reduction. It will bear any over-spend.

A.2 How distributors used the DMIA

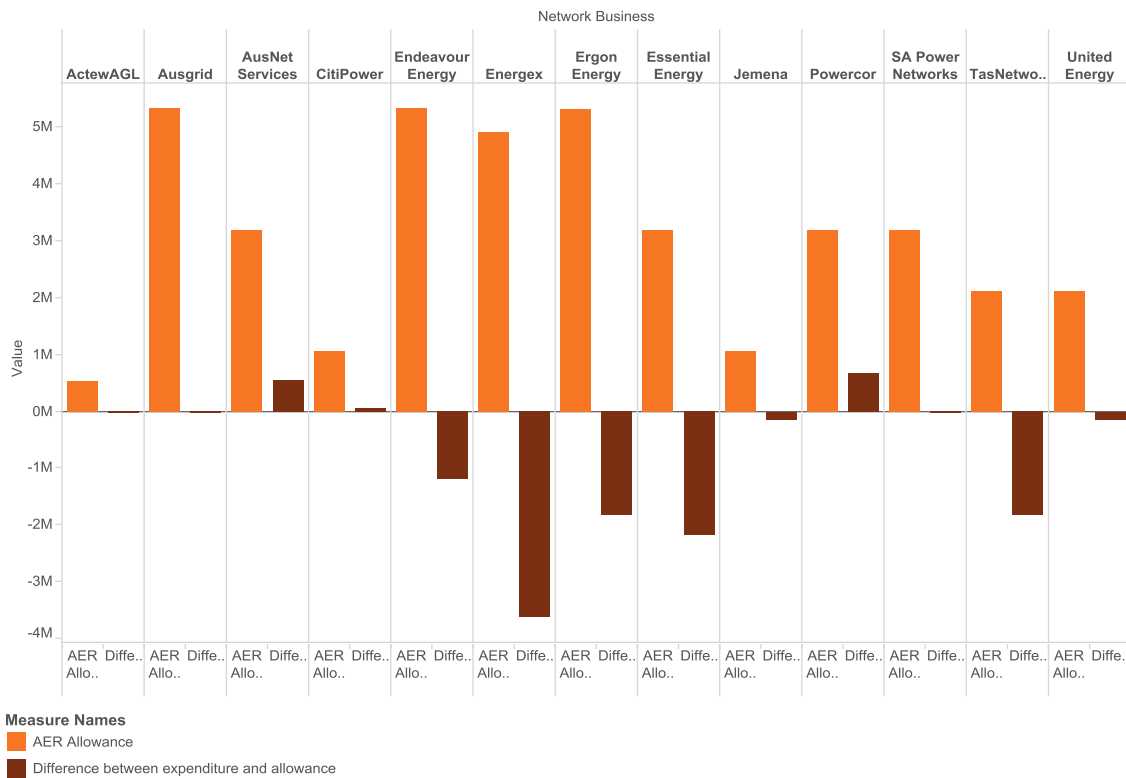
This section analyses investments provided under the Current Scheme. This information provides insight into the level of expenditure we have approved, and the type of projects the Current Scheme has delivered.

Distributors had different appetites for utilising funding under the DMIA. Figure 5 compares our total allowance with actual expenditure by distributor since the scheme commenced. We have approved every DMIA expenditure project claimed by every distributor to date. Since the scheme commenced:

- Three distributors have exceeded their allowance — AusNet Services, Citipower and Powercor.
- Three distributors have delivered projects equalling their allowance — ActewAGL Ausgrid and SA Power Networks.
- Seven distributors have not spent their full allowance — Endeavour Energy, Energex, Ergon Energy, Essential Energy, Jemena Electricity Networks, TasNetworks and United Energy.

While the size of the overspend does not exceed \$1 million, the level of under expenditure ranges from \$1 million to almost \$4 million.

Figure 5 Comparison of expenditure with allowance



It would be beneficial to better understand why several distributors underutilised their DMIA. There has previously been some discussion around this. For instance, distributors have suggested that the DMIA would be better utilised if there was:

- Increased certainty around the guiding objectives and design principles (Energy Networks Association). The Energy Networks Association also suggested that underutilisation of the Current Scheme was due to it insufficiently addressing other important barriers to efficient levels of demand management.⁹⁰
- More certainty of funding for projects over multiple regulatory control periods and less prescriptive codes that limit project scope (Ergon Energy).⁹¹
- More funding available so that the DMIA was more meaningful to distributors' circumstances (the NSW distributors).⁹²
- Greater certainty and a more effective incentive regime (Energex).⁹³

We have approved every DMIA expenditure project that distributors claimed as the expenditure complied with the DMIA criteria. Figure 6 summarises the types of projects

⁹⁰ ENA, *Demand management incentive scheme: Response to AEMC consultation paper*, 19 March 2015, pp. 1, 3.

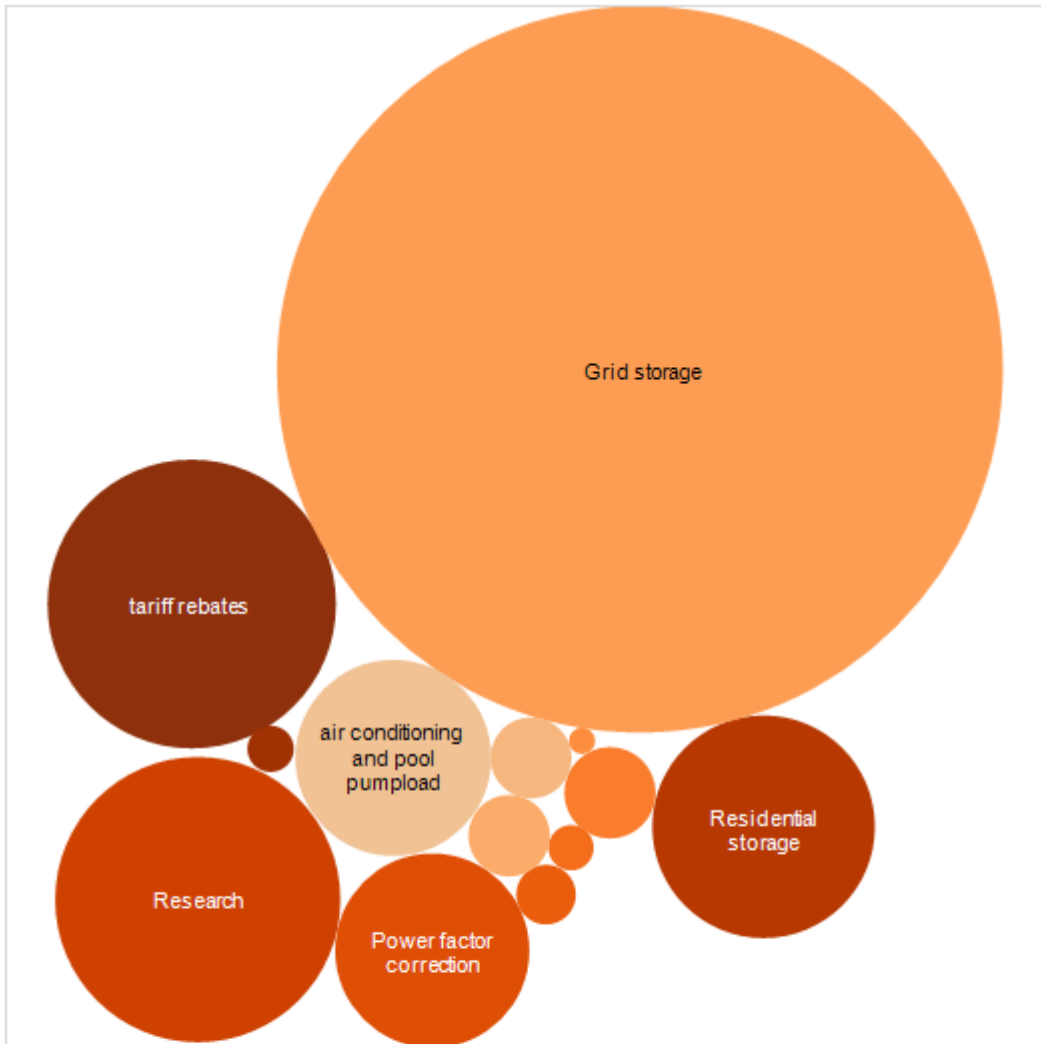
⁹¹ Ergon, *Submission to the consultation paper*, 19 March 2015, p. 5.

⁹² NSW distribution network service providers, *Submission on AEMC consultation paper*, 19 March 2015, p. 7.

⁹³ Energex, *Submission on AEMC consultation paper*, 19 March 2015, p. 4.

provided under the Current Scheme. The greater the expenditure on a project type the larger the bubble.

Figure 6: Breakdown of expenditure by project



projects

- | | |
|---|-------------------------|
| air conditioning and pool pumload control | Pool Pump Trial |
| demand scheduling | Power factor correction |
| embedded energation connection | Research |
| Grid storage | Residential storage |
| hot water connections | solar forecasting |
| In house display and airconditioning load control | tariff rebates |
| load control of hot water systems | Virtual Power Plant |

The projects included tariff based measures designed to incentivise customers to reduce their usage at times of peak demand. These included piloting tariffs to test customer response to time-of-use tariffs designed to shift load off the peak demand period. Non-tariff based projects included:

- Trials of technologies with the potential to reduce and/or shift demand, such as providing financial incentives to reduce usage during hot days.
- Improving the storage of renewable energy generated during non-peak times for subsequent use during peak periods, such as deployment of grid scale and residential batteries to off-set peak demand.
- Improving power factor correction to reduce the amount of energy losses.
- Load control options which result in shifting load to non-peak times, such as controlling the operation time of swimming pool pumps.

A.3 Compliance and reporting under the DMIA

The DMIA requires distributors to provide an annual report on their DMIA expenditure and to provide for each project an explanation demonstrating compliance against the DMIA criteria with reference to:⁹⁴

1. the nature and scope of each demand management project or program
2. the aims and expectations of each demand management project or program
3. the process by which each project or program was selected, including the business case for the project and consideration of any alternatives
4. how each project or program was/is to be implemented
5. the implementation costs of the project or program and
6. any identifiable benefits that have arisen from the project or program, including any off peak or peak demand reductions.

However, there has been a wide variation in the quality of the reports provided. The reports have varied in the amount of information provided on the project undertaken, in terms of their pre-project descriptions and justification, and their post-project reporting of results and project justification. This is partly due to variation in projects, but appears to be mainly due to variation between distributors in their understanding and execution of their requirements to document projects.

Several possible reasons contribute to this variation in annual reporting quality, including:

- The descriptions of the elements of the project explanation, listed above, are not sufficiently prescriptive to ensure that distributors provide a high quality report. For example, distributors have discretion over whether they vaguely describe how they implemented each project or whether they provide a detailed explanation that enables the reader to fully appreciate how it executed the project.

⁹⁴ See AER, *Demand management incentive scheme: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, April 2009, p. 7.

- The DMIA project criteria do not support the need for distributors to provide quality reporting, as justification that a project meets the criteria can usually be given in one or two brief sentences per criterion.
- DMIA project criteria 2, 3, 4 and 6 cannot be used as a compliance criteria in assessing proposed DMIA projects for approval, as the criteria serve only to categorise what type of demand management project is being undertaken (that is, broad-based or peak demand, innovative or not, tariff or non-tariff, using opex or capex expenditure). We would approve the project as long as it satisfied criterion 1, regardless of the responses to criteria 2, 3, 4 and 6. Consequently none of these criteria encourage comprehensive project reporting, or greatly assist the project approval process.
- The DMIA project criterion 3 is ambiguous and unclear. This criterion requires that projects 'may be innovative' but does not require that the projects must be innovative, and does not define 'innovative'. Distributors have varied in how they have documented and justified their projects against this criterion.
- The DMIA project criteria do not align with or support the need to provide the six elements of the project explanation. The information a distributor could provide on the nature and scope of a project, probably would be sufficient to address four of the six project criteria. The criteria do not clearly support the need to provide information on any of the remaining five elements of the project explanation.
- The lack of alignment between the DMIA project criteria and the six elements of the project explanation has resulted in duplication and confusion in reporting in some cases. Some distributors are reporting projects against the criteria and then repeating the process by reporting projects against the project explanation elements. In contrast, others describe some of their project characteristics against criteria and others against explanation elements, resulting in fragmented project reporting.
- No DMIA project criteria or elements of the project explanation require the distributor to report or publish results. This is with the exception of identifying any benefits from the project.

These issues with the project explanation requirements and the project approval criteria have resulted in inconsistent project reporting and poor project reporting in some cases. Poor reporting of projects undermines the ability of distributors to justify projects and for stakeholders to be reassured that funds allocated to demand management research projects are an appropriate expenditure. Given the majority of distributors can effectively document their projects, and all distributors would need to document their projects for internal reporting and management, there does not appear to be any justification for the poor reporting as being due to excessive administrative burden.