RULE CHANGE

Australian Energy Market Commission

RULE DETERMINATION

National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015

Rule Proponents

COAG Energy Council
Total Environment Centre

20 August 2015

Inquiries

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About the AEMC

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

Summary

This final rule determination sets out changes to the rules that aim to balance incentives for distribution businesses to undertake demand management projects as alternatives to implementing network options. The objective of the changes is to encourage distribution businesses to make efficient decisions with respect to network investment such that consumers' demand for electricity services is met at lowest total system costs.

The Australian Energy Market Commission (Commission or AEMC) has made this final rule determination in response to rule change requests proposed by the Council of Australian Governments (COAG) Energy Council and the Total Environment Centre (TEC). These rule change requests, which have been consolidated, largely stemmed from recommendations in the AEMC's Power of Choice review.

The final rule (a more preferable rule) 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 distribution businesses have no financial incentive to factor in the broader market benefits from non-network options and they may have limited incentives to trial new non-network options.

This rule is intended to complement existing opportunities for businesses to consider non-network options, including through their revenue allowance and the regulatory investment test for distribution project assessment process. Where a non-network option is more efficient, existing incentives in the broader regulatory framework will encourage distribution businesses to pursue the most cost efficient solution, regardless of whether it is provided by the distribution business itself or a third party.

The final rule, which is the same as the draft rule (subject to some minor drafting clarification) amends and strengthens the existing Demand Management and Embedded Generation Connection Incentive Scheme arrangements set out in Chapter 6 of the National Electricity Rules. The framework, which will be separated into two parts and renamed, will provide greater clarity to the Australian Energy Regulator (AER) and stakeholders in respect of how a mechanism to encourage efficient demand management should be designed and applied. The two parts to the framework are as follows:

- **Demand management incentive scheme** - the objective of the incentive scheme is to provide distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme will reward distribution businesses for implementing relevant non-network options that deliver net cost savings to retail customers, where it is efficient to do so.

- **Demand management innovation allowance** – the objective of the innovation allowance is to provide distribution businesses with funding for research and development in demand management projects that have the potential to reduce

long term network costs. The allowance will be used to fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

The final rule is broadly in line with the intent of the rules proposed by the proponents, but is less prescriptive in the approach it takes to address the issues identified by the proponents in their rule change requests.

The key features of the final rule, which are also common to the changes proposed by the TEC and the COAG Energy Council, are as follows:

- Creation of separate provisions in the National Electricity Rules for a demand management incentive scheme and a demand management innovation allowance mechanism.[1]
- Introduction of an objective for the incentive scheme, and a separate objective for the innovation allowance, specifying what each of these must aim to achieve.
- Introduction of a set of principles for the incentive scheme, and a separate set of principles for the innovation allowance, intended to guide the AER in developing and applying each of these to help achieve their respective objectives.
- Requirement for the AER to develop and publish the incentive scheme and innovation allowance in accordance with the distribution consultation procedures, by 1 December 2016.

Also consistent with the proposed changes, the final rule allows the AER to decide whether to apply the incentive scheme and innovation allowance to a distribution business. It is expected that the AER will apply the scheme where it considers the incentives on that business are not working as intended, resulting in bias against pursuing efficient non-network options.

The final rule will provide improved clarity for stakeholders on the intent of the incentive scheme and innovation allowance. At the same time, it will provide the AER with the flexibility to determine how to integrate the scheme and allowance into the broader framework that incentivises and encourages efficient demand management by distribution businesses, in accordance with future developments in the market.

The AEMC has made a number of reforms recently to encourage distribution businesses to make efficient decisions with regard to exploring and implementing demand management initiatives. These include changes to the distribution network planning and expansion framework, the framework for the economic regulation of network service providers and the arrangements for connecting embedded generation.

The AEMC has also introduced new requirements for distribution businesses to set network prices that reflect the efficient cost of providing network services to individual consumers. This will allow consumers to make more informed decisions about their

1 The demand management innovation allowance mechanism is referred to in this final rule determination as the innovation allowance.

energy use, and will support businesses to develop network tariff structures that incentivise efficient demand response by consumers.

Together with this rule change, these reforms provide distribution businesses with incentives to make efficient decisions about their network, undertake investment at least cost, provide opportunities for third parties to offer non-network solutions through information provision and the planning process and signal the cost of network use.

The Commission is satisfied that the final rule will, or is likely to, contribute to the achievement of the NEO compared to the current arrangements by:

- providing a framework to guide the AER in developing and applying a demand management incentive scheme and innovation allowance to help balance the incentives on distribution businesses to make efficient expenditure decisions which should lead to lower overall system costs and, in turn, lower retail prices for consumers;
- introducing a demand management incentive scheme objective and principles to guide the AER in developing an incentive scheme which supports efficient decision making by the distribution businesses and, if applied to the businesses, will encourage efficient expenditure which is in the long term interests of consumers; and
- introducing a demand management innovation allowance mechanism objective and principles to guide the AER in developing an innovation allowance which encourages distribution businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long run network costs and so prices for consumers.

The Commission is also satisfied that the final rule will, or is likely to, better contribute to the achievement of the NEO than the proposed changes by providing a better balance between prescription and flexibility.

The final rule is broadly consistent with the views put forward by stakeholders in submissions to the consultation paper and draft rule determination. In submissions to the draft rule determination most stakeholders were supportive of the draft rule, the proposed objectives and principles and the balance between prescription and flexibility for the AER. Of the 16 submissions received, only three were not supportive of the draft rule on the basis that it would give distribution businesses an unfair advantage in the competitive market for demand management services.

Several submissions raised concerns with two core components of the draft determination: providing the AER with the discretion to apply the incentive scheme and innovation allowance to distribution businesses; and not implementing the rule change midway through the regulatory control period. Further, some stakeholders considered that distribution businesses should be required to report on projects pursued under the incentive scheme. One stakeholder also sought more prescription in the way that rewards could be applied.

The consolidated rule change request stemmed from the 2012 AEMC Power of Choice review which set out a market-wide reform program to, among other things, improve the incentives on distribution businesses to use demand management to reduce overall capital and operating costs. These inter-related reforms related to the arrangements for:

- distribution network pricing, which were finalised in November 2014;
- competition in metering and related services, a draft of which was published in March 2015; and
- this demand management incentive scheme and innovation allowance.

Contents

1 The consolidated rule change request

This final determination addresses two rule change requests submitted to the Australian Energy Market Commission (AEMC) in relation to the incentives for distribution businesses to pursue efficient demand management and embedded generation connections. These were submitted in response to recommendations made by the AEMC in its Power of Choice review, completed in November 2012.

1.1 The rule change requests

On 22 November 2013, the Total Environment Centre (TEC) submitted a rule change request proposing amendments to the demand management and embedded generation connection incentive scheme (DMEGCIS). The TEC's rule change request seeks to make it easier for the Australian Energy Regulator (AER) to design and implement a "reformed DMEGCIS" that will help to incentivise distribution businesses to undertake demand management projects as an alternative to building new network infrastructure. It is intended to complement existing obligations on these businesses to examine non-network alternatives to new network investment as part of the regulatory investment test for distribution (RIT-D) process.

On 17 December 2013, the Council of Australian Governments (COAG) Energy Council[2] submitted a rule change request which also proposed to amend the DMEGCIS arrangements.[3] The COAG Energy Council's rule change request seeks to achieve an appropriate return to distribution businesses to incentivise efficient demand management projects, as well as to improve clarity and certainty around how the scheme will be developed and implemented. This is intended to strengthen the incentives for distribution businesses to undertake demand management projects that deliver a net benefit to consumers.

The COAG Energy Council and TEC rule change requests seek to amend the DMEGCIS arrangements set out in Chapter 6 of the National Electricity Rules (NER or rules). Details of the rule changes proposed by the proponents are set out in section 1.4, and in Table 4.1, of this final rule determination.

As the COAG Energy Council rule change request covers similar issues to those presented in the TEC rule change request, the Commission decided to consolidate the two rule change requests. This has enabled a single consultation and decision process.

2 The COAG Energy Council was formerly called the Standing Council on Energy and Resources.

3 The COAG Energy Council rule change request was developed based on recommendations contained in the AEMC's Power of Choice review. It is part of the broad energy reform package to support investment and market outcomes in the long term interests of consumers as agreed by COAG and SCER in December 2012. See: COAG Energy Council, rule change request, cover letter.

1.2 Current arrangements

1.2.1 NER requirements

Chapter 6 of the NER provides the AER with the discretion to develop and publish a DMEGCIS. The purpose of the scheme, as stated in the NER, is to:[4]

> "...provide incentives for *Distribution Network Service Providers* to implement efficient non-*network* alternatives, or to manage the expected demand for *standard control services* in some other way, or to efficiently connect *Embedded Generators*."

The NER requires that, in developing and implementing the scheme, the AER must have regard to a number of factors, including:[5]

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for distribution businesses;
- the effect of a particular control mechanism, (that is price – as distinct from revenue – regulation) on a distribution business's incentives to adopt or implement efficient non-network alternatives;
- the extent the distribution business is able to offer efficient pricing structures;
- the possible interaction between a DMEGCIS and other schemes under Chapter 6 of the NER;[6]
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme; and
- the effect of classification of distribution services as determined in accordance with clause 6.2.1 on a distribution business's incentive to adopt or implement efficient embedded generation connections.

1.2.2 Current scheme design and application

The AER has developed a DMEGCIS under the existing rules framework and has applied it as part of the distribution determinations of all distribution businesses in the national electricity market (NEM). Because the AER decided to continue similar schemes established by jurisdictional regulators prior to the introduction of the NER

4 NER clause 6.6.3(a).

5 NER clause 6.6.3(b).

6 The other incentive schemes in Chapter 6 of the NER are: the efficiency benefit sharing scheme (EBSS) under clause 6.5.8, the capital expenditure sharing scheme (CESS) under clause 6.5.8A, the service target performance incentive scheme (STPIS) under clause 6.6.2 and the small scale incentive scheme (SSIS) under clause 6.6.4.

for its first round of distribution determinations under the NER, different schemes apply in different jurisdictions. However, the AER's DMEGCIS schemes for each distribution business are generally divided into two parts:

- Part A: demand management innovation allowance (DMIA); and
- Part B: foregone revenue component.

Part A is an innovation allowance that provides funding to distribution businesses to trial innovative demand management and embedded generation connections schemes. It is provided to distribution businesses in the form of a fixed amount of additional revenue at the commencement of each year of the current regulatory control period. In the second year of the next regulatory control period, when results for the five years of the current regulatory control period are known, a single adjustment is made to return the amount of any underspends or unapproved DMIA amounts to consumers.

The AER annually assesses any claims for the DMIA against criteria it has developed and set out in the DMEGCIS. The criteria are descriptive and allow for a wide range of projects to be approved.

Part B is a payment to distribution businesses designed to address the impacts that certain forms of control (such as the price cap) may have on a distribution business's incentives to undertake efficient demand management. It allows the distribution businesses to recover foregone revenue in a regulatory control period, resulting from a reduction in the quantity of energy sold directly attributable to demand management projects or programs approved under Part A of the scheme. However, no claims for foregone revenue under Part B of the scheme have been made by distribution businesses to date.

A key objective of the DMEGCIS is to assist in enhancing industry knowledge of practical demand management projects and programs through the annual publication of demand management incentive scheme reports from distribution businesses.[7] Distribution businesses are required to submit an annual report to the AER on their demand management incentive scheme expenditure at the end of each year. The information provided in a distribution business's annual demand management incentive scheme report is used in the AER's assessment of a distribution business's compliance with the DMIA criteria and entitlement to recover expenditure under the DMIA.

The DMEGCIS is not intended to be the sole, or even the primary, source of recovery of demand management expenditure by a distribution business. Rather, its purpose is to complement the incentive regulation structure by supplementing a distribution business's approved capital expenditure (capex) and operating expenditure (opex) to facilitate investigation and implementation of demand management strategies. It also aims to correct any disincentives that might discourage distribution businesses from undertaking demand management.

7 AER, 2011–12 and 2012 DMIA assessment, Decision, July 2013.

1.3 Rationale for rule change request

The proponents of the two rule change requests considered that the existing DMEGCIS developed and applied by the AER has not been effective in encouraging an efficient level of demand management in the market.[8] The reasons identified in the rule change requests reflect the issues that were identified by the AEMC in its Power of Choice review:[9]

- The current scheme focuses on cost recovery only and does not provide distribution businesses with an opportunity to make profits on demand management projects. In this sense, the scheme is not a true incentive scheme that allows a distribution business to earn extra rewards where it has delivered defined goals.
- The innovation allowance has been modest and potentially too limited in scope to genuinely encourage experimentation and innovation with new demand management methods.
- Any reward available to distribution businesses for undertaking demand management projects was of relatively short duration relative to the long term returns available on network investment.
- Distribution businesses have not been able to capture the benefits from demand management initiatives created at other levels of the supply chain - for example, the benefits associated with reduced generation capital and operating expenditure.
- There is uncertainty as to whether demand management related expenditure would be treated differently compared to normal capital and operating expenditure under the NER (for example, considered less prudent with respect to the expenditure objectives and criteria under NER clauses 6.5.6 and 6.5.7).

Both of the proponents noted that there are greater uncertainties and risks associated with demand management options compared with traditional network investment and that the stable returns generally associated with capital expenditure meant the businesses were likely to favour capital investment as the means for addressing network limitations and demand growth.[10] To support this view, the TEC noted that demand management was currently less than two per cent of NEM-wide peak demand and only about one per cent of the generation capacity in the NEM.[11]

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8 COAG Energy Council, rule change request, pp3-4.

9 The Power of Choice review explored, among other things, the reasons why the distribution businesses did not appear to be reacting to the incentive framework in place at the time, in respect of pursuing demand side options. The AEMC subsequently recommended a number of reforms to the rules for the DMEGCIS. These consolidated rule change request are based on those recommendations.

10 ibid.

11 TEC, rule change request, p4.

In this context, the proponents did not consider that the existing DMEGCIS was providing sufficient incentive or certainty for distribution businesses to explore and develop efficient demand management options as an alternative to network investment.

1.4 Solutions proposed in the rule change requests

The COAG Energy Council and TEC rule change requests seek to address the issues raised above by amending the DMEGCIS arrangements in Chapter 6 of the NER. The objective is to assist the AER to strengthen the incentives for distribution businesses to undertake demand management projects that deliver a net benefit for consumers.

The two proposals share a number of key features as they were both developed having regard to the recommendations made by the AEMC in its Power of Choice review. The amendments to Chapter 6 of the NER which are common to both rule change requests are as follows:

- Explicit separation of the current DMEGCIS into a demand management incentive scheme (DMIS) and a demand management incentive allowance (DMIA).
- Introduction of an explicit objective, and set of principles, to guide the AER in its development and application of the DMIS.[12]
- Providing scope for the AER to include two forms of reward under the DMIS:
  - a payment based on a proportion of the net market benefits (or avoided or deferred network costs) produced by a demand management project; and
  - a payment as compensation for any lost revenues or profits that occur as a result of reduced demand from implementing a demand management option, where appropriate.

While similar in their overarching objectives, the COAG Energy Council and TEC rule change requests differ in their details:

- In respect of the payment to distribution businesses of a proportion of net market benefits directly attributable to demand management projects, the COAG Energy Council rule change request specifies that distribution businesses would be able to retain a maximum of 30 percent of the associated non-network related market benefits, while the TEC rule change request specifies a maximum of 50 percent.;
- In respect of the payment to distribution businesses as compensation for a reduction in demand resulting from demand management projects, the COAG Energy Council rule change request proposes that the allowance be for forgone profit, while the TEC rule change request proposes an allowance for foregone revenue.

12 The proposed wording of the objective and principles differ slightly between the proponents.

- The COAG Energy Council rule change request would clarify that only non-tariff based demand management projects would be included within the scope of the incentive scheme,[13] the TEC rule change request proposes to include both tariff and non-tariff based projects within the scope of the scheme.

- The COAG Energy Council rule change request would require the AER to develop guidelines for how incentive payments would be determined, including guidance on the calculation of benefits available for reward and the calculation of lost profits to be compensated.

A detailed comparison of the common features and key differences between the current rules and the arrangements proposed by the COAG Energy Council and TEC in their rule change requests, are set out in Table 4.1 in Chapter 4.

1.5 Background to the rule change requests

The AEMC completed the Power of Choice review in November 2012 and recommended to the COAG Energy Council a package of reforms designed to encourage consumers to make more efficient consumption choices that trade off the value of consuming electricity against the cost of supplying that electricity.[14]

Amongst other things, the AEMC recommended several rule changes designed to provide distribution businesses with better incentives to use demand management to reduce overall capital and operating costs.

In relation to distribution networks and demand management, the review examined whether the regulatory arrangements were providing the right incentives for distribution businesses to implement demand management projects as an efficient alternative to network capital investment. This work was carried out in response to a concern from some stakeholders that distribution businesses were not reacting to the current incentive arrangements in respect of pursuing efficient demand side options, as intended.

The review identified a number of reasons why this may be the case, including:

- issues with the existing regulatory arrangements (from the way financial incentives were applied to how network tariffs were set); and

- individual business preferences, practices and experiences.

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13 While both tariff and non-tariff based demand management projects would be eligible for funding under the innovation allowance, only non-tariff based projects would be included within the scope of the incentive scheme (that is, eligible for the foregone revenue compensation payment).

14 The overall objective of the Power of Choice review was to ensure that the community's demand for electricity services is met by the lowest cost combination of demand and supply side options. This objective is best met when consumers are using electricity at the times when the value to them is greater than the cost of supplying that electricity (that is, the cost of generation and poles and wires). See: AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney.

The Power of Choice review made a number of recommendations in relation to the incentives for distribution businesses to undertake demand management projects that provide net benefits for consumers. Some of these were taken forward and implemented in the AEMC's new distribution network pricing arrangements rule.[15] The recommendations made in relation to the DMEGCIS arrangements are the subject of these rule change requests.

At the time of the Power of Choice review, a number of other rule changes were also being progressed by the Commission which related to the existing regulatory arrangements for distribution businesses:

- The Economic regulation of network service providers rule change request (network regulation rule change request) addressed, among other things, how the current arrangements provide incentives for efficient capital and operating expenditure and determine the allowed rate of return.[16]
- The Distribution network planning and expansion framework rule change request considered issues associated with how distribution businesses include demand management alternatives in their planning and project assessment process.[17]
- The Connecting embedded generators rule change request provided a clearer, more transparent connection process with defined timeframes and information requirements to reduce barriers to the connection of embedded generators to distribution networks.[18]

1.6 The Commission's rule making process

On 19 February 2015, the Commission published notices advising of:

- the consolidation of the COAG Energy Council and TEC rule change requests;[19] and
- its commencement of the rule making process and the first round of consultation in respect of the consolidated rule change request.[20]

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15 The new distribution network pricing arrangements rule, introduced in November 2014, requires distribution businesses to set prices that reflect the efficient cost of providing network services to individual consumers. This will allow consumers to make more informed decisions about their use of electricity. Network prices based on the new pricing objective and pricing principles introduced by the rule will be gradually phased in from 2017.

16 AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper, 29 November 2012, Sydney.

17 AEMC 2012, Distribution Network Planning and Expansion Framework, Rule Determination, 11 October 2012, Sydney.

18 AEMC 2014, Connecting Embedded Generators, Rule Determination, 17 April 2014, Sydney.

19 This notice was published under s.93(1)(a) of the National Electricity Law (NEL).

20 This notice was published under s.95 of the NEL.

A consultation paper prepared by AEMC staff identifying specific issues and questions for consultation was also published with the notice.

Submissions on this first round of consultation closed on 19 March 2015. The Commission received 2,717 submissions in total. Two online campaigns coordinated by Choice and Solar Citizens resulted in a total of 2,679 submissions being received.

Choice provided the opportunity for individuals to provide a submission to the AEMC's consultation paper on the DMIS rule change request through its website. To facilitate this, Choice provided a template submission that people were able to add their name to and forward to the AEMC by email.

The AEMC received a total of 1,106 submissions from the public through Choice's website. Of these submissions, 1,067 followed the template submission. A list of those individuals is contained on the AEMC's website.[21] This list does not include the 27 people that requested their names not be made public.

The AEMC also received a further 39 submissions that deviated from the template, which are also reproduced on the AEMC's website.[22]

Solar Citizens also provided the opportunity for individuals to provide a submission to the AEMC's consultation paper through its website. To facilitate this, Solar Citizens required each individual's submission to be submitted in accordance with the AEMC's Privacy Policy.

The AEMC received a total of 1,573 submissions from the public through Solar Citizen's website. Of these submissions: 1,014 individuals requested their submission be published with their name and post code; 446 individuals requested their submission be published without their name; and 113 individuals requested their submission be kept confidential. The submissions from individuals that requested their submission be published are available on the AEMC's website.[23]

The Commission has considered all submissions received in response to the consultation paper. Given the statutory framework within which the Commission operates, the matters that the Commission gives weight to when deciding whether to make rules are matters that are relevant and of value as evidence of whether the proposed rule contributes to the National Electricity Objective. Many of the submissions received in response to the Choice and Solar Citizens campaigns did not address relevant issues related to the consolidated rule change request.

A summary of the key issues raised in submissions and the Commission's response to each issue is contained in Appendix A.1.

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21 CHOICE campaign, consultation paper submissions.

22 ibid.

23 The AEMC published the submissions from Solar Citizens in two documents. Part A contains those submissions from individuals that requested their submission be published in addition to their name and post code and Part B contains those submissions with name withheld. See Solar Citizens - Part A, and Solar Citizens - Part B, consultation paper submissions.

On 28 May 2015, the Commission published a notice under section 99 of the NEL and a draft rule determination in relation to the consolidated rule change request. The draft rule determination included a more preferable draft rule.

Submissions to the draft rule determination closed on 9 July 2015. A total of 16 submissions were received. These submissions are available on the AEMC website.

Where relevant to the discussion, the Commission has summarised the issues raised in submissions as part of its analysis throughout Chapters 3 to 6, with any outstanding issues summarised and addressed in Appendix A.2.

The final rule is the same as the draft rule, subject to some minor drafting clarification. However, this final rule determination clarifies a number of issues raised in submissions to the draft rule determination and draft rule.

2 Final rule determination

The Commission's final rule determination is to make a more preferable rule (final rule). The final rule is broadly in line with the intent of the rules proposed by the COAG Energy Council and the TEC, but is less prescriptive in the approach it takes to address the issues identified by the proponents in their rule change requests.

The final rule is the same as the draft rule, subject to minor drafting changes.

The final rule will enable the AER to design and apply a demand management incentive scheme (DMIS or incentive scheme) and a demand management innovation allowance (DMIA or innovation allowance)[24] which supports efficient decision making by the distribution businesses and which promotes efficient investment in, and operation of, the distribution networks in the long term interests of consumers.

This chapter outlines:

- the Commission's rule making test for changes to the NER;
- the Commission's assessment framework for considering the rule change request; and
- the Commission's consideration of the final rule against the national electricity objective (NEO).

Further information on the legal requirements for making this final rule determination is set out in Appendix B.

2.1 Rule making test

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective. This is the decision making framework that the Commission must apply.

The NEO is:

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

24 For ease, the demand management incentive scheme and the demand management innovation allowance are at times referred to as the demand management incentive mechanism.

In this case, the relevant aspects of the NEO are the promotion of efficient investment in, and operation of, distribution electricity services for the long term interests of consumers with respect to price.

2.2 Assessment framework

Investing in and operating the networks in the long term interests of consumers means that network reliability, safety, security and quality requirements are met at efficient long term cost. This outcome will be achieved if a number of conditions are met:

- **Demand is met at lowest total system cost**: Incentive-based regulation provides incentives for distribution businesses to behave in a way that lowers overall total system costs which, over time, will lead to price and/or reliability, safety, security and quality benefits for consumers. In other words, the regulatory framework should promote efficient decision making that encourages distribution businesses to identify and pursue the most efficient (or least cost) solution that can deliver the required level of supply reliability, irrespective of whether that solution is a network or non-network option.;

- **Efficient investment in and use of assets takes place**: The incentives applied through the regulatory framework are an important determinant of how efficient distribution businesses invest in and maintain their infrastructure. The regulatory framework should therefore aim to enable:

  - use of existing assets to be optimised;[25]

  - the network to be managed to meet changing demand;[26] and

  - assets to be replaced at the end of their useful life if it is necessary and efficient to do so.[27]

- **Distribution businesses are able to recover efficient costs**: The regulatory framework should only allow for an efficient level of costs to be recovered by distribution businesses, rather than allowing an automatic pass-through of all expenditure. This would promote efficient investment in distribution networks while allowing the businesses to recover the efficient costs of owning and operating their networks.

- **Efficiency and innovation are rewarded:** There should be a positive relationship between efficiency and reward, and the distribution businesses should be incentivised to make improvements in efficiency.

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25 Using the existing infrastructure to its optimal capacity means that additional investment is not taking place before the full value of the existing assets has been realised. If assets are under-utilised or replaced before the end of their useful lives, demand will not be met at efficient long term cost.

26 All available options to manage changing demand are considered, including building new infrastructure, expanding existing infrastructure or meeting or managing demand in other ways.

27 Decisions are made on a holistic basis about maintenance of existing assets, investment in new assets and other options such as demand side management.

The Commission's assessment has considered the extent to which the amendments proposed by the COAG Energy Council and the TEC in their rule change requests, and the final rule, enable the AER to design and apply a demand management incentive mechanism which supports these conditions and therefore which promote the NEO.

The amendments, and the final rule, have been assessed against the relevant counterfactual arrangement. In this case, the counterfactual is the existing provisions in Chapter 6 of the NER.

In considering the consolidated rule change request, the Commission has analysed the two key components of the incentive mechanism – the DMIS and the DMIA – separately. Where there are matters relevant to both components, the Commission has considered these under the banner of the 'demand management incentive mechanism'.

2.3 Summary of reasons

The final rule is attached to and published with this final rule determination. The final rule is broadly in line with the intent of the rules proposed by the proponents, but provides less prescription. The key features of the final rule are:

- Creation of separate provisions in the NER for a demand management incentive scheme and the demand management innovation allowance mechanism.[28]
- Introduction of an objective for the incentive scheme, and a separate objective for the innovation allowance, specifying what these must aim to achieve.
- Introduction of a set of principles for the incentive scheme, and a separate set of principles for the innovation allowance, intended to guide the AER in developing and applying these to meet their respective objectives.
- Requirement for the AER to develop and publish the incentive scheme and innovation allowance in accordance with the distribution consultation procedures, by 1 December 2016.

The final rule includes a number of consequential amendments. These are discussed further in section 2.5.

Further details on the final rule can be found in Chapters 4 to 6 of this final rule determination.

The Commission is satisfied that the final rule will, or is likely to, contribute to the achievement of the NEO compared to the current arrangements by:

- providing a framework to guide the AER in developing and applying a demand management incentive scheme and innovation allowance to help balance the incentives on distribution businesses to make efficient expenditure decisions

28 The demand management innovation allowance mechanism is referred to in this final rule determination as the innovation allowance.

which should lead to lower overall system costs and, in turn, lower retail prices for consumers;

- introducing a demand management incentive scheme objective and principles to guide the AER in developing an incentive scheme which supports efficient decision making by the distribution businesses and, if applied to the businesses, will encourage efficient expenditure which is in the long term interests of consumers; and
- introducing a demand management innovation allowance objective and principles to guide the AER in developing an innovation allowance which encourages distribution businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long run network costs and so prices for consumers.

The Commission is also satisfied that the final rule will, or is likely to, better contribute to the achievement of the NEO than the proposed changes by providing a better balance between prescription and flexibility. This will support the AER in developing and applying an incentive scheme and innovation allowance that are consistent with their respective objectives, while being flexible and adaptable to future developments in the market and regulatory arrangements.

The final rule will provide improved clarity for stakeholders on the intent of the incentive scheme and innovation allowance. At the same time, it will provide the AER with the flexibility to determine how to integrate the scheme and allowance into the broader framework that incentivises and encourages efficient demand management by distribution businesses. The final rule will encourage more efficient decisions by distribution businesses that have the potential to reduce costs to consumers over time.

2.4 Strategic priority

This consolidated rule change request is relevant to the AEMC's strategic priority relating to market arrangements that encourage efficient investment and flexibility. Consistent with the reasons set out in the previous section, the final rule will encourage the development of incentives which support efficient decision making by distribution businesses and, consequently, efficient investment that minimises costs to consumers. It will also provide the AER with an appropriate level of flexibility to allow it to adapt to changing circumstances.

2.5 Consequential amendments

The final rule includes a number of consequential amendments to the NER. These are:

- replacing reference to the demand management and embedded generation connection incentive scheme with references to the demand management incentive scheme and the demand management incentive allowance mechanism;

- adding new definitions to, and removing obsolete definitions from, Chapter 10 of the NER; and

- replacing references to non-network alternatives with non-network options in Chapters 6 and 6A of the NER.

In respect of the latter, 'non-network options' is a term locally defined and used in Chapter 5 of the NER. In contrast, 'non-network alternatives' is not defined in the NER, although it arguably is used throughout the rules to capture what is now defined in Chapter 5 as a non-network option. As explained later in this final rule determination, the final rule uses non- network option rather than non- network alternatives in relation to the DMIS. The Commission considers that this term better captures the policy intent of the DMIS, in that the efficient expenditure that the incentive scheme seeks to incentivise relates to expenditure on options which are not network options, and which can fully (or partly) address an identified need on a distribution network.[29] This matter is discussed further in section 6.4.

Under Chapters 6 and 6A of the NER, the AER has obligations to consider how the various incentive schemes interact, as they relate to non-network alternatives. It also has obligations about information it must take into account in relation to non- network alternatives as part of the regulatory process. Without updating these references to 'non-network option', there will be inconsistencies in the drafting within Chapters 6 and 6A of the NER. This could lead to confusion in the interpretation of obligations. Therefore, given that the amendments will not change the intent of the current obligations in those chapters, the final rule replaces reference to 'non-network alternatives' with 'non-network options' in the NER.

The consequential amendments are contained in Schedule 2 of the final rule which is published with this final rule determination.

29 An identified need is defined in Chapter 5 of the NER as the objective that a network businesses seeks to achieve by investing in the network.

3 Distribution businesses and demand management

This chapter explores a number of preliminary questions related to the role of distribution businesses in managing demand on their networks, and the need for an incentive scheme specific to demand management. The Commission has had regard to the views put forward by stakeholders in submissions to the consultation paper and draft rule determination, as well as its own analysis, when considering these matters.

This chapter sets out:

- a summary of the existing regulatory framework and how it contributes to investment in demand management;
- a discussion of why distribution businesses have a role in managing demand on their networks;
- an explanation of why there is a gap in the existing frameworks and therefore the need for this rule;
- a summary of the role of the regulatory investment test for distribution (RIT-D);
- a discussion of the application of demand management to transmission networks; and
- a discussion of the treatment of demand management related expenditure.

3.1 Overview of the regulatory framework supporting demand management

The regulatory framework relating to demand management by distribution businesses is primarily set out in Chapters 5, 5A and 6 of the NER. It uses incentives and obligations to encourage distribution businesses to generate outcomes that consumers need, want and are willing to pay for, and to do so efficiently and in line with jurisdictional reliability standards.

With respect to demand management, the objective of the regulatory framework is to achieve an outcome where distribution businesses pursue and develop demand management projects when these are at least as efficient as network capital investment. The framework will be consistent with this objective if it leads to an outcome where consumers' demand for electricity is met by the lowest cost combination of demand and supply side options.

In this context, the current incentive frameworks and obligations in the NER are designed to encourage distribution businesses to make efficient investment and expenditure decisions. They do so by better balancing the incentives (or savings) between capital and operating expenditure, and between network and non-network investment. The relevant aspects of the broader incentive frameworks and obligations in the NER are set out in Box 3.1 below.

Box 3.1 Incentive frameworks and obligations in the NER

Broadly, the promotion of efficient investment and expenditure relate to two areas of the regulatory framework for distribution businesses, the planning and investment framework and the incentive regulation framework.

These frameworks encourage consideration of non-network options, provide information to businesses that may offer non-network solutions, and provide distribution businesses with incentives to invest in least-cost options.

Planning and investment framework

Included in Chapter 5 of the NER, the distribution network connection, planning and expansion framework is designed to encourage distribution businesses and network users to make efficient planning and investment decisions. It does so by creating obligations on, and a framework within which, distribution businesses can explore non-network options as alternatives to network investment.

The key components of this framework include the distribution annual planning report (DAPR), demand side engagement strategy (DSES) and the RIT-D and associated RIT-D project assessment process.

- DAPR: Distribution businesses must publish a DAPR. The report provides information on: capacity and load forecasts; system limitations; any recently completed, underway or planned RIT-D process; other committed projects which are urgent and unforeseen, or replacement and refurbishment projects; information on demand management activities; and other high level summary information, to provide important context to DNSPs' planning processes and activities.

- DSES: Distribution businesses are required to develop a DSES. The published strategy details a business' processes and procedures for assessing non-network options as alternatives to network expenditure and interacting with non-network providers. Distribution businesses are also required to maintain a register of parties interested in being notified of developments relating to distribution network planning and expansion.

- RIT-D: Distribution businesses are required to go through a RIT-D process to identify investment options which best address an identified need on the network. The RIT-D applies to network augmentation projects in circumstances where a network problem exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $5 million. As part of the RIT-D process, distribution businesses must also consider non-network options when considering credible options to address the identified need.

Incentive regulation framework

Set out in Chapter 6 of the NER, the incentive regulation framework is designed to encourage distribution businesses to spend efficiently and to share the benefits of efficiency gains with consumers. Specifically, it is designed to encourage distribution businesses to make efficient decisions on when and what type of expenditure to incur in order to meet their network reliability, safety, security and quality requirements.

These incentives are important as the majority of demand management expenditure is expected to be funded through operating expenditure.

The key incentive schemes include the efficiency benefit sharing scheme (EBSS), and the capital expenditure sharing scheme (CESS) and associated ex-post review mechanism for capital expenditure.

- EBSS: The EBSS provides distribution businesses with an incentive to reduce operating expenditure throughout the regulatory period, balances the incentives between operating and capital expenditure and provides a mechanism to share efficiency gains and losses between network businesses and network users.
- CESS: The CESS provides distribution businesses an incentive to reduce capital expenditure throughout the regulatory period, balances the incentives between operating and capital expenditure and provides a mechanism to share efficiency gains and losses between network businesses and network users.
- Ex-post review mechanism for capital expenditure: If a distribution business' capital expenditure exceeds the estimate of efficient capital expenditure set out in its revenue determination, it is subject to a limited form of review at the end of each regulatory period to ensure that only prudently incurred capital expenditure is included in the regulatory asset base (RAB) in future regulatory periods. If it is determined that all or some of the overspending was inefficient, the business may not be allowed to add the excess spending to its RAB. This provides an additional incentive for network businesses to only undertake efficient capital expenditure.

The previous rules also included arrangements which allowed the AER to develop and apply a demand management and embedded generation connection incentive scheme. The then DMEGCIS arrangements recognised that there are a number of risks and issues associated with demand management which meant that the planning and investment framework, and the incentive regulation structure, may not have been sufficient to encourage distribution businesses to pursue demand management solutions over network capital investment, where it was efficient to do so. Those issues included the following:

- Demand management was relatively new.

- Demand management on distribution networks may have spill over benefits for other parts of the electricity supply chain which distribution businesses may not consider when making investment decisions.

- Under certain control mechanisms (that is, price cap regulation), distribution businesses may have reduced incentives to pursue demand management solutions because reductions in demand result in reductions in the maximum regulated revenue that the business is permitted to earn.

The intent of the then DMEGCIS arrangements was therefore to provide distribution businesses with an appropriate financial reward for pursuing demand management projects where these provided an efficient alternative to network capital expenditure. The DMEGCIS developed and applied by the AER under the previous rules was explained in section 1.2 of this final rule determination.

3.2 The role of distribution businesses in demand management

Investment by distribution businesses is generally driven by the need to build sufficient network capacity to meet the relevant reliability standards mostly at times of peak demand. In certain circumstances, demand management initiatives can reduce, defer or remove the need for network investment by dampening peak demand.

Reductions in peak demand of this type can be driven by demand management that is price responsive - that is, induced by consumers responding to price signals and achieved without prior knowledge by the system operator, retailer or network business. They can also be driven by contracted demand management, which involves a direct compensation payment or incentive to consumers who agree to alter their electricity use, or have their load controlled, under certain defined circumstances.[30][31]

If the need to meet peak demand and any reliability measures were to be addressed solely through price responsive demand management, the need for distribution businesses to manage peak demand through building additional network capacity or pursuing contracted demand management opportunities, will be lessened.

Stakeholder views

In its submission to the consultation paper, the AER questioned whether regulated networks were best placed to interact with the demand side, given that demand management could be provided competitively. It also questioned how an appropriate

30 Demand side resources which can supply capacity, ancillary services and energy reduction with a high degree of certainty tend to be covered by such payments. Examples include network support agreements and direct load control.

31 Embedded generation provides customers with an option of substituting their consumption of electricity from the network with their own generation. A customer would seek to use embedded generation in this way where the benefits of doing so were greater than the costs. Importantly however, customers may wish to connect embedded generators for a range of reasons other than to provide network support. In this sense, embedded generation could provide both contracted and uncontracted demand management.

separation of monopoly and competitive services could be maintained in the event distribution businesses do have a role in interacting with the demand side. The AER considered that clarity around the role of network businesses in demand management was an important first step in understanding the behaviour that a demand management incentive might encourage.[32]

GDF Suez Australia considered that incentivising distribution businesses to pursue demand management options would not support efficient outcomes and therefore could be inconsistent with the NEO. It considered such an approach would undermine a market based approach to demand management and consumer choice.[33,34]

In its submission to the consultation paper, the Energy Efficiency Council considered that distribution businesses were in a unique position to deliver system wide efficiency by: first, providing tariffs or incentives that encourage an efficient balance of investment in supply and demand side services; and second, directly investing in a balanced portfolio of supply and demand side services themselves.[35]

In its submission to the draft rule determination, AGL considered that while distribution businesses should always consider demand management solutions as an alternative to investment in infrastructure, distribution businesses should not be able to use their regulatory funding to offer consumers demand management services. AGL considered that this would undermine the competitive market for demand side technologies and services, which it submitted are fundamental for consumer choice and engagement.[36]

EnergyAustralia noted in its submission to the draft rule determination that there are risks to competitive neutrality where “the procurer of a service, the information holder and the decision maker” also compete for the provision of that service.[37] It suggests that consideration should be given as to whether a distribution business should be prevented from providing demand management services to itself.[38]

Similarly, in its submission to the draft rule determination, Snowy Hydro considered that the draft rule would provide distribution businesses with a competitive advantage with asymmetrical information and a regulated revenue stream not available to other parties that can provide demand management services.[39]

32 AER, consultation paper submission, p.1.

33 GDF Suez Australia, consultation paper submissions, p.6.

34 GDF Suez Australia, draft rule determination submission, p.1.

35 Energy Efficiency Council, consultation paper submission, p.1.

36 AGL, draft rule determination submission, p.2.

37 EnergyAustralia, draft rule determination submission, p.2.

38 Ibid., p.3.

39 Snowy Hydro, draft rule determination submission, pp.1-2.

Commission's view

The Commission has considered the role of distribution networks in managing demand, particularly in light of the purpose of the recent reforms to distribution network pricing and the proposed reforms to the metering arrangements. It has also had regard to the views put forward by stakeholders in submissions to the consultation paper and draft rule determination on this matter.

The AEMC recently amended the NER in respect of the way the distribution businesses set and structure network prices. The changes require the businesses to develop network tariffs which better reflect their cost drivers. This will allow consumers to make more informed decisions about their energy use as new technologies emerge and result in better outcomes for both individual consumers and the overall electricity system. Importantly, it also provides a framework for the businesses to develop network tariff structures which appropriately incentivise efficient demand side responses by consumers, for example, through shifting some consumption to lower cost off-peak times or by installing technologies that help reduce their peak demand, for example, load control.

Related to the above pricing amendments, is the competition in metering rule change request currently being considered by the AEMC. If implemented, the changes proposed would lead to a greater penetration of advanced meters in the NEM, in turn allowing for more sophisticated ways of measuring and pricing a consumer's electricity use. In particular, these technologies offer much better ways to send signals about the network costs caused by a consumer's usage and promote more efficient use of the network to the benefit of all consumers.

The new distribution network pricing arrangements introduced by the AEMC in November 2014, coupled with the possible introduction of competition in metering, are likely to move the market toward a future where there may be less need for the distribution businesses to actively manage demand on the networks themselves. If networks priced efficiently and all electricity consumers were willing and able to respond to prices and manage their own demand, the need for the networks to manage peak demand would not be an issue.

However, moving towards this outcome will take considerable time, given that it would require, among other things, the possible changes to the existing metering arrangements to be implemented and to take effect and for distribution businesses to develop tariffs that appropriately signal network costs.

In addition, and perhaps more importantly, the market is unlikely ever to reach the point where price signals mean that there are no network constraints at peak times. This is because it would require highly volatile and very high prices at times of peak demand. It would also require all electricity consumers to be actively engaged and respond rapidly to price changes. In respect of the latter, consumer interests, motivation, willingness and ability to manage electricity use and costs depend on a range of different factors, of which the availability of demand side participation opportunities is just one.[40]

In practice, these conditions are unlikely to be achieved in full. For this reason, the Commission notes that distribution businesses will always have a role in managing demand on their networks. More specifically, distribution businesses will always need to decide whether network or non-network solutions provide the most efficient means of meeting or managing peak demand, and meeting reliability standards.

The Commission acknowledges the issues raised by the AER, AGL, EnergyAustralia, GDF Suez Australia and Snowy Hydro regarding the role of distribution businesses in demand management in light of the competitive provision of demand management services by retailers and third parties.

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

The incentive scheme, where it applies to a distribution business, will apply regardless of whether demand management services are provided by the distribution business or by a third party. For this reason, the Commission does not consider that this rule will provide distribution businesses with a competitive advantage. Rather, it will provide a tool to encourage the businesses to make a balanced decision as to whether to implement a network or non-network option and may create opportunities for third party providers by incentivising distribution business to consider and pursue efficient demand management options where they otherwise may not have done so.

Through a distribution business' DAPR, third parties have access to information that indicates where opportunities to provide demand management services may exist. Among other things, this report provides details on current and forecast network limitations. This information could be used by third parties to take a more informed view of the potential for non-network options to offer appropriate and efficient solutions to network constraints.

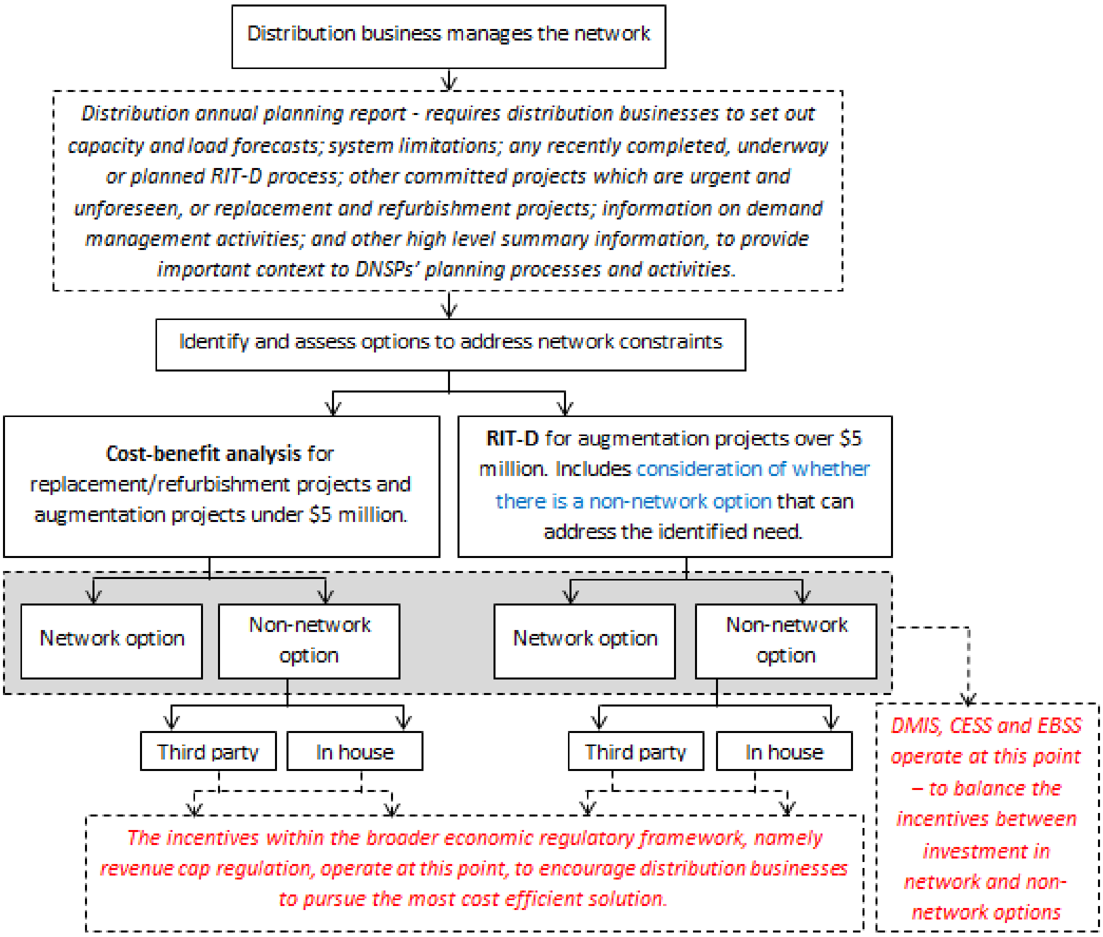
Further, under the RIT-D arrangements distribution businesses explore and identify non-network alternatives for all proposed network augmentation over five million dollars. Under the RIT-D consultation procedures distribution businesses are required to prepare and publish a non-network options report. This report helps distribution businesses to identify potential non-network options and be better informed on the costs and market benefits associated with a potential investment option. These

40 For further information of consumer awareness, education and engagement in relation to demand side participation (DSP), see: AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney, Chapter 2.

arrangements provide opportunity for third parties to consider how they could provide demand management services to distribution businesses at the network level. The RIT-D arrangements are discussed further in section 3.4 below.

The framework described above is illustrated in Figure 3.1. As outlined in the diagram, the incentive scheme operates at the point where a distribution business considers whether to invest in a network or non-network option to address an identified network constraint. If a non-network option is the more efficient solution, the party who provides the service should be the party that can provide it at lowest cost. In this way, the Commission considers that the final rule may encourage growth in the competitive market for demand management services.

Figure 3.1 Impact of the incentive scheme on the competitive market for demand management services



The Commission considers that the rules, the frameworks they create and the arrangements they support, as outlined above, encourage the distribution businesses to make efficient network expenditure and investment decisions. This should lead to lower overall system costs which should, in turn, be reflected in lower retail prices for consumers.

3.3 The need to incentivise demand management in the NEM

In the consultation paper published for the consolidated rule change request, consideration was given to whether there is a gap in the current regulatory framework for distribution businesses which may be discouraging the businesses from pursuing demand management projects as an efficient alternative to network investment.

It was acknowledged that recent changes in market conditions - specifically the recent weakening of electricity demand – had (among other things) resulted in a reduction in the number of planned network investments, including the deferral of projects that had already passed a regulatory investment test.

There was also recognition that the regulatory framework for distribution businesses has undergone considerable change since completion of the Power of Choice review in 2012. Concerns raised in that review in relation to distribution businesses' tendency to favour network investment over non-network solutions have been mitigated, at least to some extent, by a number of reforms specifically targeted towards distribution businesses and their motivation for pursuing demand management.

At the time of the Power of Choice review, a number of rule changes were being progressed by the Commission which related to the existing regulatory arrangements for distribution businesses.[41] Collectively, these reforms have been changing the way distribution businesses engage with non-network providers, and consider and assess demand management options as efficient alternatives to network capital investment.

In addition, and as noted in the previous section, recent reforms to the distribution network pricing arrangements coupled with the successful introduction of competition in metering, will encourage efficient demand side responses by consumers

Stakeholder views

In submissions to the consultation paper, stakeholders considered whether recent reforms to the market and regulatory arrangements mean that there is no longer a need for a specific mechanism to incentivise the distribution businesses to pursue demand management as an efficient alternative to network investment.

In its submission to the consultation paper, EnerNOC considered that while recent reforms to the regulatory framework imposed obligations on distribution businesses to consider demand management projects, these obligations did nothing to motivate the business to pursue these projects. EnerNOC considered that distribution businesses have considerable freedom to choose whatever option suits their preferences and

41 These were described in Chapter 1 and include the economic regulation of network service providers rule change request (network regulation rule change request); the distribution network planning and expansion framework rule change request; and the connecting embedded generators rule change request.

therefore concluded that incentives matter to encourage them to choose non-network options where they are the most efficient.[42]

In their submission to the consultation paper, the NSW Distribution Network Service Providers (NSW DNSPs)[43] expressed the view that recent reforms to distribution pricing and metering should be considered as complementary to the DMEGCIS arrangements and the consolidated rule change request, rather than replacement measures. They noted that while these reforms were related in the sense that they all aimed to facilitate greater levels of demand side participation, each reform was intended to address different issues with the market and regulatory arrangements.[44]

In its submission to the consultation paper, Origin Energy noted that the current DMEGCIS had only resulted in a modest uptake of demand management to date and that this, in an environment of rapid network expansion, was indicative of the current incentives on distribution businesses to pursue demand management were skewed in favour of network capital investment.[45]

In contrast, GDF Suez Australia considered that the broader regulatory incentive structure currently applied to distribution businesses was sufficient to incentivise them to pursue efficient demand management. Specifically, it considered that the weighted average cost of capital (WACC) and efficiency benefit sharing scheme, by providing two offsetting incentives, were sufficient to encourage efficient expenditure decisions by the businesses.[46]

The Public Interest Advocacy Centre considered that an effective incentive scheme was required to combat cultural barriers that exist to demand management within the distribution businesses.[47]

In its submission to the draft rule determination, GDF Suez Australia submitted that the implementation of cost reflective network pricing would remove the need for an incentive scheme or innovation allowance.[48]

In its submission to the draft rule determination, AGL considered that distribution businesses should not be provided with additional incentives to provide demand management services behind the meter or directly to consumers. AGL noted that there are a number of incentives being developed to promote demand management activities behind the meter, including cost reflective network pricing. These incentives are likely

42 EnerNOC, consultation paper submission, pp.1-2.

43 The NSW Distribution Network Service Providers are Ausgrid, Endeavour Energy and Essential Energy.

44 NSW DNSPs, consultation paper submission, p.3.

45 Origin Energy, consultation paper submission, p.1.

46 GDF Suez Australia, consultation paper submission, p.3.

47 Public Interest Advocacy Centre, consultation paper submission, p.2.

48 GDF Suez Australia, draft rule determination submission, p.1.

to encourage the uptake of demand management services, removing the need for the rule change.[49]

Similarly, Snowy Hydro considered that the combination of cost reflective network pricing and the installation of more advanced meters will move the market to a point where there is less need for distribution businesses to manage demand on their networks. Snowy Hydro also noted that other incentives, including the CESS and EBSS are sufficient to incentivise distribution businesses to invest in non-network options.[50]

The AER noted in its submission to the draft rule determination that it will take time for cost reflective network pricing to impact on efficient levels on network investment and it is difficult to know the impact that this will have on the level of demand management.[51]

Commission's view

The Commission acknowledges there remains a concern among some stakeholders that, even with the new distribution pricing arrangements and other recent changes to the regulatory framework aimed at encouraging efficient expenditure decisions by the distribution businesses, in practice, there is still a bias towards investment in network options at the expense of more efficient non-network solutions.

If the current arrangements fail to provide the right motivation for distribution businesses to pursue demand management as an efficient alternative to network investment, then the network businesses will meet or manage peak demand growth by investing in more supply side infrastructure. The cost of doing so will be recovered from consumers through retail prices.

While recent reforms have been changing the way distribution businesses engage with non-network providers, and consider and assess demand management options as efficient alternatives to network investment, it may take some time before these reforms result in efficient demand management being considered and pursued as business as usual by the distribution businesses.

It is for this reason that the Commission considers there is still a need to provide the AER with a tool to allow it develop and apply an incentive scheme for demand management. The scheme will be applied by the AER where it considered that the incentives on a distribution business are not working as intended, resulting in bias against pursuing efficient non-network options by distribution businesses.

The rules governing such a scheme therefore need to be able to support the AER to develop and apply a scheme that is effective in balancing the incentives between network and non-network investment. This will promote efficient decision making by the distribution businesses which should result in lower overall total system costs to the benefit of consumers.

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49 AGL, draft rule determination submission, p.2.

50 Snowy Hydro, draft rule determination submission, p.1.

The Commission emphasises that the intention of the final rule is to balance the incentives between network and non-network investment, not to incentivise non-network investment over network investment. There will be scenarios in which the most efficient option to address a network constraint is network investment and the final rule is constructed in such a way as to not discourage that option from being pursued where it is the most efficient.

3.4 Regulatory investment test for distribution

In submissions to the consultation paper, a number of stakeholders provided comments on the elements of the distribution network planning and expansion framework set out in Chapter 5 of the NER.

CitiPower and Powercor commented that the relative costs of demand management compared to network solutions had limited the ability of distribution businesses to implement demand management alternatives (non-network solutions being the more expensive alternative). In addition, CitiPower and Powercor considered that the RIT-D arrangement could be 'limiting the competitiveness of non-network options given the difficulties associated with valuing the deferral of network investment that these options provided'. It considered this was potentially undervaluing investments in innovative non-network solutions.[52]

Ergon Energy commented on the RIT-D arrangements in the context of prescription. It considered that the rules were currently overly prescriptive in respect of the way in which distribution businesses must pursue demand management opportunities. It cited the RIT-D as an example of how overly prescriptive rules could inhibit innovation opportunities for demand management, market engagement and customer involvement. It noted that high levels of prescription in times when the market is undergoing significant change may reduce the ability for distribution businesses to adapt and transform to those changing circumstances.[53]

The AER acknowledged that various changes had been made to its regulatory approaches which may help to achieve balanced consideration of network and non-network options by distribution businesses. However, it considered it was also worth exploring whether existing measures which require the distribution businesses to consider network and non-network options equally, could be expanded. Specifically,

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51 AER, draft rule determination submission, p.2.

52 CitiPower and Powercor noted that by deferring expensive network solutions, non-network solutions tended to create 'option value' ie, future benefits that may not be realisable at the time of the RIT-D process but that may ultimately provide synergistic benefits to the non-network option. These future benefits generally occur due to technological change. This means that where a non-network solution is able to defer network investment to a time in the future, evolution of technologies between now and that future time may be able to delay further, or conceivably completely avoid the need for the network investment. See: CitiPower and Powercor, consultation paper submission, p.5 and Appendix A.

53 Ergon Energy, consultation paper submission, p.3.

it suggested that the RIT-D could be expanded to include replacements and refurbishment assets.[54]

In its submission to the draft rule determination, AusNet Services argued that expanding the scope of the RIT-D to include replacement and refurbishment is unnecessary and a disproportionate response to the issues to be addressed. AusNet Services considered that the incentive scheme would work in combination with the existing distribution planning framework and the RIT-D to provide for consideration and implementation of non-network options.[55]

Commission's view

As noted in section 3.1, the distribution network planning and expansion framework is a key component of the regulatory framework for distribution businesses. It is designed to encourage distribution businesses and other network users to make efficient planning and investment decisions. It does so by creating obligations on, and a framework within which, distribution businesses can explore non-network options as alternatives to network investment. The RIT-D and associated process is a key component of this framework as noted in section 3.2.

Although out of scope of this rule change process, it is important that these arrangements are operating effectively to achieve the intended outcomes. In the instance the rules are not operating as intended, or are leading to outcomes which are not consistent with the NEO, stakeholders may propose a change to the NER. In this context, stakeholders may wish to consider whether the scope of the RIT-D should be extended to include replacement and refurbishment assets.

3.5 Transmission businesses and demand management

Under the current rules, the demand management incentive scheme is only available for distribution businesses and not transmission businesses.

In submissions to the consultation paper, EnerNOC, Grid Australia, the Energy Networks Association (ENA) and Transgrid suggested that the scope of the consolidated rule change request be expanded to include consideration of the current regulatory framework for demand management by transmission businesses.[56] Broadly, these stakeholders considered that by limiting the scope of the demand management incentive scheme and demand management incentive allowance to distribution businesses only, an opportunity would be missed to consider total system benefits of demand management across the NEM.

In its submission to the draft rule determination, the Public Interest Advocacy Centre (PIAC) also called for the scope of the rule change to be expanded to include the

54 AER, consultation paper submission, pp.1-2.

55 AusNet Services, draft rule determination submission, pp.4-5.

56 EnerNOC, consultation paper submission, p.3; Grid Australia, consultation paper submission, pp.1-2; ENA, consultation paper submission, p.2; Transgrid, consultation paper submission, pp.1-2.

application of the incentive scheme and incentive allowance to transmission businesses.[57] Similarly, the ENA suggested that consideration should be given as to how transmission businesses could participate in a demand management market.[58]

The Commission has considered the views put forward by these stakeholders in their submissions. It recognises that transmission businesses can, and do, contribute to effective demand management, albeit in a more limited capacity compared to the demand side and distribution businesses. Transmission businesses are also required to consider the potential for demand management options (non-network options) under the regulatory investment test for transmission (RIT-T).

Further, the AER can provide funding for non-network solutions through operating expenditure and has done so in the past. For example, for its 2009 to 2014 regulatory control period, Transgrid received a specific funding allowance from the AER to undertake demand management innovation activities similar to the innovation allowance that is available to distribution businesses (this was approved at $1million per annum). In its current regulatory determination process (for the period 2015-16 to 2017-18), Transgrid is again seeking an operating expenditure allowance to undertake further demand management innovation activities.[59]

However, in the context of this rule change process, the Commission considers that consideration of the application of a demand management incentive scheme and innovation allowance to transmission businesses is out of scope.

Stakeholders have the ability to raise a rule change request to apply a similar framework to transmission businesses where they consider it would better achieve the NEO.

3.6 Treatment of demand management related expenditure

In their submission to the consultation paper, the NSW DNSPs considered the intent of the consolidated rule change request would be frustrated without consideration of the ability for distribution businesses to gain approval for funding of demand management projects outside of those funded by capex savings or the RIT-D (that is, included in the expenditure allowance). It suggested that these issues could be addressed by, among other things, amending the rules to clarify that the AER can have regard to potential non-network market benefits when assessing the efficiency of proposed demand management activities included in a distribution business' revenue proposal.[60]

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57 PIAC, draft rule determination, pp.2-3.

58 ENA, draft rule determination submission, p. 4

59 Transgrid, consultation paper submission, p.3.

60 NSW DNSPs, consultation paper submission, pp.13-14.

This matter was considered by the AEMC in its Power of Choice review and was reflected in the TEC's rule change request. Specifically, the TEC proposed amendments to NER clauses 6.5.6 and 6.5.7 to:[61]

- introduce a new capex and opex objective which would aim to ensure efficient and prudent use of non-network alternatives, including demand management; and
- introduce a new capex and opex factor which requires the AER to have regard to the extent to which a distribution business has considered the potential non-network benefits of demand management in its revenue proposal.

The Commission has considered this proposal but does not consider it is necessary to amend these expenditure objectives and factors, as proposed by the TEC. The Commission considers that the current regulatory framework, in addition to the revisions to the operation of the demand management incentive scheme and the innovation allowance would be sufficient to address these proposed changes.

In addition, the regulatory framework currently requires the AER to have regard to whether a distribution business has considered efficient and prudent non-network alternatives when considering whether a distribution business' proposal reasonably reflects the operating and capital expenditure criteria, respectively.[62]The Commission is concerned that amendments to include additional obligations regarding consideration of non-network options may be duplicative and so could lead to a lack of clarity.

In the draft rule determination, the Commission considered that there may be benefits in the AER explaining how it will assess the efficiency of demand management project expenditure as part of the regulatory determination process. This would provide some certainty to distribution businesses regarding the AER's approach to the approving an expenditure allowance for demand management projects. The Commission noted that this could be done in the expenditure forecast assessment guidelines, which set out the AER's proposed approach to assessing forecasts of operating and capital expenditure.[63]

In its submission to the draft rule determination, the AER noted that it does not take a unique assessment approach to demand management projects and did not consider that assessment of demand management projects required special treatment over the assessment of other expenditure proposals. The AER noted that the expenditure forecast assessment guidelines outline the types of assessments the AER undertakes in determining expenditure allowances and the information required for distribution businesses to facilitate those assessments. It considered that the guideline provides

61 TEC rule change request, p.12.

62 NER clauses 6.5.6(e)(10) and 6.5.7(e)(10).

63 These guidelines are required under NER clause 6.4.5(a).

guidance to distribution businesses on how the AER will likely assess expenditure forecasts and the information that it requires to do so.[64]

However, in light of this rule, the AER noted that it will consider whether it is necessary to amend the expenditure forecast assessment guidelines or otherwise set out its assessment approach to demand management in more detail.[65]

64 AER, draft rule determination submission, p.3.

65 Ibid., p.4.

4 Demand management incentive mechanisms

This chapter sets out the Commission's views in relation to the matters and proposed amendments which are relevant to both the demand management incentive scheme and the demand management innovation allowance mechanism. In considering these matters, the Commission has had regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 4.1 provides a recap of the issues with the current arrangements as identified by the proponents in their rule change requests;
- sections 4.2 and 4.3 describe the key amendments as proposed by the proponents, and summarise stakeholder responses to the consultation paper on these matters;
- section 4.4 summarises stakeholder responses to the draft rule determination;
- section 4.5 provides a description of the final rule; and
- sections 4.6 and 4.7 then provide a summary of the Commission's analysis of the relevant issues and amendments, and set out its conclusions on these matters.

Issues specific to the incentive scheme and to the innovation allowance are then considered in Chapters 5 and 6, respectively.

4.1 Introduction

As noted in Chapter 1, the regulatory framework for distribution includes a number of mechanisms and measures designed to encourage efficient expenditure decisions by the distribution businesses and remove potential regulatory biases towards network capital investment. The arrangements for a DMEGCIS are one such measure.

However, as set out in their respective rule change requests, COAG Energy Council and the TEC consider that the current DMEGCIS developed and applied by the AER under the existing rules has not been effective in encouraging an efficient level of demand management in the market. The reasons cited are as follows:

- The current scheme focuses on cost recovery only and does not provide distribution businesses with an opportunity to make profits on demand management projects. As such, the scheme is not a true incentive scheme that allows a distribution business to earn extra rewards where it has delivered defined goals.
- The innovation allowance has been modest and potentially too limited in scope to genuinely encourage experimentation and innovation with new demand management methods.

- Any reward available to distribution businesses for undertaking demand management projects was of relatively short duration relative to the long term returns available on network investment.

- Distribution businesses have not been able to capture the benefits from demand management initiatives created at other levels of the supply chain - for example, the benefits associated with reduced generation capital and operating expenditure.

- There is uncertainty as to whether demand management related expenditure would be treated differently compared to normal capital and operating expenditure under the NER (for example, considered less prudent with respect to the expenditure objectives and criteria under NER clauses 6.5.6 and 6.5.7).

To address these issues, the proponents proposed a series of amendments to Chapter 6 of the NER. These are intended to guide the AER in its development and application of a DMEGCIS which provides strong incentives for distribution businesses to undertake demand management projects that deliver a net benefit for consumers.

A comparison of the current arrangements with the amendments proposed by COAG Energy Council and the TEC is provided in Table 4.1 below. It also highlights the areas of commonality with the Commission's final rule.

Table 4.1 Comparison of the current NER arrangements with the rule change proposals and final rule

Demand management and embedded generation connection incentive scheme	Current rules[66]	COAG proposals	TEC proposals	Final rule
Separate DMIS and DMIA	×	✓	✓	✓
Demand management incentive scheme (DMIS)				
Application of scheme				
Explicit objective (scheme must be applied consistent with the objective)	× (implicit objective)	✓	✓	✓
Principles (scheme must be applied consistent with principles)	✓(specified in the rules as principles and factors to have regard to)	✓	✓	✓
Requirement to publish scheme (AER must publish)	×	✓ (within 9 months of rule)	✓ (within 9 months of rule)	✓ (by 1 July 2016)
Process to develop/amend scheme (in accordance with rule or distribution consultation procedures)	✓ (develop - distribution consultation procedures)	✓ (develop and amend - distribution consultation procedures)	✓ (amend - rules consultation procedures)	✓ (develop and amend - distribution consultation procedures)
Development of scheme				
Factors to consider (scheme must be developed consistent with certain factors)	✓	✓	✓	✓ (develop in

66 In many instances below, the key feature described is implicit in the current rules, that is, is within the scope of the objectives and factors set out under clause 6.6.3.

Demand management and embedded generation connection incentive scheme	Current rules[66]	COAG proposals	TEC proposals	Final rule
				accordance with the objective and principles)
Information requirements (AER to determine information needed from distribution businesses to monitor scheme)	×	✓	✓	×(develop in accordance with the objective and principles)
Scheme rewards - non-network market benefits				
Determination of share retained (AER discretion to determine percentage of non-network market benefits to be retained)	×(not specified in the rules)	✓ (but not specified in proposed specifications)	✓	× (AER discretion to develop in accordance with principles)
Maximum percentage retained	×	✓ (30 per cent)	✓ (50 per cent)	× (AER discretion to develop in accordance with principles)
Consistency with RIT-D guidelines (in relation to standardised values of non-network market benefits)	×	× (AER guideline)	✓	× (AER discretion to develop in accordance with principles)
Scheme rewards - foregone revenue/profit				
Allowance for foregone revenue/profit (arrangements specified in the NER)	✓ (foregone revenue but not	✓ (foregone	✓ (foregone	× (AER discretion to

Demand management and embedded generation connection incentive scheme	Current rules[66]	COAG proposals	TEC proposals	Final rule
	specified in the NER)	profit)	revenue)	develop in accordance with principles)
Factors to consider (AER to have regard to tariff structure and costs)	×	× (AER guideline)	✓	× (AER discretion to develop in accordance with principles)
Consistency with proposed demand response mechanism methodologies (in relation to determining value of consumer demand response)	×	✓	✓	× (AER discretion to develop in accordance with principles)
Other aspects				
AER guidelines (AER to publish guidelines to support application of the scheme)	×	✓	×	× (final rule does not include an explicit requirement for the AER to prepare guidelines)
AER annual assessment report (AER to publish report on effectiveness of scheme)	×	✓	×	× (not specified in the final rule)
Demand management innovation allowance (DMIA)				
AER flexibility to determine amount of innovation allowance	✓ (but not specified in the	✓	✓	✓ (contained within one of the

Demand management and embedded generation connection incentive scheme	Current rules[66]	COAG proposals	TEC proposals	Final rule
	NER)			principles)
Information requirements (Distribution businesses to provide relevant information from pilots/trials to the AER for publication)	×	✓	✓	✓ (final rule includes an explicit requirement for reporting)
Link to distribution annual planning reports (Approved projects to be published in annual planning reports)	×	✓	✓	× (AER discretion to determine in accordance with principles)
Consideration of domestic/international activities (AER must consider uniqueness of a project having regard to domestic/international activities)	×	✓	×	× (AER discretion to determine in accordance with principles)
Consideration of other funding sources (AER assessment should consider ability of distribution businesses to seek other funding for projects)	×	✓	×	✓ (contained within one of the principles)
AER guidelines (AER to publish guidelines on DMIA)	×	✓	×	× (final rule does not include an explicit requirement for the AER to prepare guidelines)

Demand management and embedded generation connection incentive scheme	Current rules[66]	COAG proposals	TEC proposals	Final rule
Capex and opex objectives				
Enable AER to consider potential non-network marker benefits when making revenue determination decisions	×	✓	✓	× (not specified in the final rule)

4.2 Proponents' views

In its rule change request, the COAG Energy Council proposed a number of amendments to Chapter 6 of the NER which it stated are intended to provide high level guidance to the AER around how a new demand management incentive scheme should be developed and implemented, while not unduly constraining the flexibility of the AER to develop and adapt its approach as circumstances and knowledge evolves.[67]

The amendments proposed by the TEC also aim to make it easier for the AER to design and implement a new incentive scheme.[68]

4.2.1 Separation of the scheme and allowance

The proponents both considered there was merit in retaining the existing innovation allowance, but to separate it from the demand management incentive scheme through the creation of separate provisions in the NER. This was to reflect the different purpose of the incentive scheme relative to the innovation allowance.

Although the proposed wording differs slightly between the COAG Energy Council and TEC rule change requests, the purpose of the new incentive scheme would be, in effect, to encourage least cost network investment and operation by allowing distribution businesses to access a proportion of the full benefits delivered by demand management options. The innovation allowance, on the other hand, focuses on providing an additional source of funding for distribution businesses to experiment and trial innovative approaches to demand management and the connection of embedded generators.[69]

4.2.2 Principles based approach

The amendments set out by the proponents in their respective rule change requests are based on the recommendations made in the AEMC’s Power of Choice review. As such, the proposed frameworks reflect a principles-based approach to the development and implementation of a scheme and allowance. The proposed amendments therefore include a high level objective and supporting principles, rather than detailed prescription in the NER.

In its rule change request, the COAG Energy Council's rationale for introducing an objective was to provide greater certainty and clarity for distribution businesses with regard to the purpose of the scheme and the circumstances under which the businesses may earn a return on demand management projects. The objective would be supported by principles and other amendments which provide guidance to the AER and the

67 COAG Energy Council rule change request, p.2.

68 TEC rule change request, p.5.

69 Chapters 5 and 6 explore, in detail, the objective and principles proposed by the proponents in their respective rule change requests.

distribution businesses for how the objective may be achieved, and seek to improve the clarity and certainty of how the AER will develop and operate the scheme.[70]

The COAG Energy Council also noted that this approach is similar to the overall approach taken by the AEMC in its economic regulation of the network service providers (network regulation) rule change in 2012.[71]

The TEC did not provide detailed reasons in its rule change request for its proposal to introduce an explicit objective and set out principles into the NER.

4.2.3 Applicable demand management projects

The TEC and COAG Energy Council's rule change requests differ in a number of respects, including in relation to the types of demand management projects to be included within the scope of the incentive scheme.

Having considered the potential risks and benefits, the COAG Energy Council decided that the demand management incentive scheme developed and applied by the AER should be limited to non-tariff based demand management activities – that is, tariff based demand management projects would be excluded.[72]

In contrast, the TEC has proposed to include both tariff and non-tariff based projects within the scope of the scheme. The TEC considered that inclusion of tariff (price) based demand management, in addition to non-tariff (project) based demand management, would encourage more demand management by providing for changing network tariffs.[73]

For the avoidance of doubt, both proponents considered that tariff and non-tariff based demand management projects should be eligible for funding under the innovation allowance, consistent with allowance applied by the AER under Part A of the current DMEGCIS.

4.2.4 Requirement to develop and apply

A feature common to both is the requirement for the AER to develop a scheme and allowance, and the discretion afforded to the AER in applying the scheme and allowance to distribution businesses. This differs from the current DMEGCIS rules which provide the AER with the discretion to develop, publish and apply a DMEGCIS.

Neither the COAG Energy Council nor the TEC provided detailed rationale for this aspect of their proposed amendments.

70 COAG Energy Council rule change request, p.5.

71 ibid, p.4.

72 ibid, p.8.

73 See TEC rule change request, pp.8,12.

The TEC subsequently submitted to the draft determination that the AER should be required to apply the scheme to distribution businesses. This is discussed further in section 4.4.

4.2.5 Development of guidelines

The current rules for the DMEGCIS do not explicitly require the AER to develop and publish a guideline to support the application of the scheme.[74]

The COAG Energy Council proposed to introduce a requirement for guidelines to be developed and published by the AER to support the application of a scheme and the allowance. The guidelines for the scheme would include the methodologies and/or approaches used to determine the value of incentive payments allowed under the scheme. The COAG Energy Council noted that such an approach would be consistent with the AER's role for developing guidelines for the calculation of the market benefits with regard to the regulatory investment test for distribution (RIT-D) under Chapter 5 of the NER.

The TEC's proposed amendments did not include an obligation on the AER in respect of guidelines. However, the TEC subsequently submitted to the draft determination that the AER should be required to develop guidelines. This is discussed further in section 4.4.

4.3 Stakeholders' views on the consolidated rule change request

Overall, stakeholders were generally supportive of the intent of the amendments proposed by the COAG Energy Council and the TEC in their rule change requests. GDF Suez Australia was the only stakeholder to oppose the broad intent of the proposed amendments in submissions to the consultation paper.[75]

The majority of stakeholders supported the proposal to include in the NER separate provisions for an incentive scheme and an innovation allowance. Stakeholders were generally of the view that such an approach would better guide the AER in its design and application of the scheme and allowance, and would provide greater clarity to distribution businesses and the broader market around how these would operate. For example, the ENA considered it was appropriate to separately represent the scheme and allowance in the rules given their different objectives, parameters and funding methodologies. In addition, it considered that clear policy objectives and guiding principles for a separate allowance and scheme were critical features absent from the current framework.[76]

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74 Apart from the Capital Expenditure Sharing Scheme (CESS), the other incentive schemes in Chapter 6 of the NER come with guidelines without these being explicitly required by the NER.

75 See GDF Suez Australia, consultation paper submission.

76 ENA, consultation paper submission, pp.2,3.

Stakeholders were generally divided on the appropriate level of discretion to afford to the AER in relation to its design and application of the scheme. While some considered that the lack of an effective scheme to date was evidence that more prescription in the rules is necessary, others argued that providing the AER with flexibility and discretion would allow the framework to be improved and adapted in response to future regulatory, market and technology changes. Ergon Energy considered that the rules can be overly prescriptive about the way in which a distribution business must pursue demand management opportunities. It cited the RIT-D as an example how overly prescriptive rules could inhibit innovation opportunities for demand management, market engagement and customer involvement.[77]

In contrast, EnerNOC considered that prescription is required, noting that while the AER had the ability to introduce an incentive scheme under the rules, it chose not to. EnerNOC considered that the rule change proposals provided the AER with too much discretion by providing the AER with an ability to impose an ineffective incentive scheme.[78]

In relation to projects applicable under the incentive scheme, the majority of stakeholders considered that both tariff and non-tariff based demand management projects should be included within the scope of the scheme and allowance. For example, NSW DNSPs considered that precluding tariff based options from funding under the scheme would limit potential benefits to consumers from network businesses being able to better utilise existing assets.[79]

Distribution businesses generally considered that including tariff based projects within the scope of the innovation allowance would encourage innovative tariff design initiatives which would support the new distribution pricing reforms. In contrast, the AER considered there was limited merit in providing additional incentives to motivate networks to undertake something that the new distribution pricing reforms would require under the NER.

Origin Energy endorsed the proposal by COAG Energy Council to require the AER to develop guidelines which set out the methodology for determining incentive payments and codify the scheme's administration. In considering the objectives and principles proposed by COAG Energy Council and the TEC, Energex considered that some of the detail proposed for inclusion in the rules may best be placed in the guidelines.[80]

77 Ergon Energy considered that high levels of prescription in times when the market is undergoing significant change may reduce ability for distribution businesses to adapt and transform. Ergon Energy, consultation paper submission, p.3.

78 EnerNOC, consultation paper submission, p.3.

79 NSW DNSPs, consultation paper submission, p.8.

80 Energex, consultation paper submission, p.3.

4.4 Stakeholders' views on the draft rule

Of the 16 submissions received in response to the draft rule determination, most were generally supportive of the draft rule. Only AGL, GDF Suez Australia and Snowy Hydro were not supportive of the draft rule.[81]

Separation of the scheme and allowance

Stakeholders were supportive of providing for a separate demand management incentive scheme and demand management innovation allowance. Origin Energy considered that the separation of the incentive scheme and the innovation allowance will provide clarity for distribution businesses, market participants, consumers and proponents of non-network projects.[82]

Principles based approach

Stakeholders noted support for the principles based approach taken in the draft rule.[83] The AER considered that a principles based approach provides flexibility so that the incentive scheme can be adapted to encourage efficient decisions by distribution businesses to utilise demand management options, including those provided by third parties.[84]

Many stakeholders considered that the balance between flexibility and prescription in the rules was correct. NSW DNSPs considered that the draft rule provided the AER with sufficient guidance to design a more effective incentive scheme and innovation allowance whilst retaining the flexibility for the schemes to be adapted over time to reflect changes in the market.[85] Similarly, EnergyAustralia considered that the draft rule allowed the AER prudent and appropriate flexibility to develop and apply the scheme alongside recent and pending market developments and, given these, consider whether there is a need to incentivise distribution business.[86]

Requirement to develop and apply

Stakeholders had mixed views in relation to the discretion afforded to the AER to apply the scheme under the draft rule. PIAC and the TEC considered that the AER

81 See AGL, draft rule determination submission; GDF Suez Australia, draft rule determination submission; and Snowy Hydro, draft rule determination submission. EnergyAustralia expressed similar concerns in relation to the impact that the draft rule would have on the competitive market for demand management services. However, they did not go as far as to express opposition to the draft rule.

82 Origin, draft rule determination submission, p.1.

83 AER, draft rule determination submission, p.2; EnergyAustralia, draft rule determination submission, p.1; ENA, draft rule determination submission, p.1; and Ergon, draft rule determination submission, p.1.

84 AER, draft rule determination submission, p.2.

85 NSW DNSPs, draft rule determination submission, p.1.

86 EnergyAustralia, draft rule determination submission, p.1.

should be required to apply the incentive scheme to all distribution determinations.[87] The TEC considered that it should be the distribution business and not the AER that has the discretion to apply the incentive scheme to their business.[88] Similarly, AusNet Services considered that leaving the application of DMIS open to AER discretion creates regulatory uncertainty and may lead to perverse outcomes where distribution businesses avoid demand management projects in order to be incentivised to invest in them.[89]

Conversely, Origin Energy and EnergyAustralia considered the draft rule afforded the AER an appropriate amount of discretion to develop and apply the incentive scheme.[90]

Development of guidelines

Some stakeholders considered that the final rule should require the AER to develop guidelines on how it would apply the incentive scheme and innovation allowance. PIAC and the TEC submitted that the distribution businesses' poor performance in relation to demand management indicates that guidelines are needed.[91]The NSW DNSPs considered that the development of guidelines would provide for greater transparency and regulatory certainty and temper the discretion of the AER.[92]

The AER noted that the incentive scheme and innovation allowance will be supported by a decision document and explanatory material, and the application of the scheme to individual distribution businesses will be consulted on in the Framework and Approach process. Therefore, it considered that a separate guideline was not needed.[93]

Applicable demand management projects

Distribution businesses generally considered that there should be no distinction drawn between the types of projects that fell within the scope of the incentive scheme and innovation allowance. AusNet Services, Energex and ENA proposed that tariff based demand management projects should fall within the scope of the incentive scheme, so that a distribution business can use a suite of tools to manage demand on their network.[94] Similarly, ENA and Ergon considered that connecting embedded generation projects should not be excluded from the types of projects within the scope of the incentive scheme or innovation allowance.[95]

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87 PIAC, draft rule determination submission , p.1; and TEC, draft rule determination submission, p.3.

88 TEC, draft rule determination submission, p.3.

89 AusNet Services, draft rule determination submission, p.3.

90 EnergyAustralia, draft rule determination submission, p.1; and Origin Energy, draft rule determination submission, p.1.

91 PIAC, draft rule determination submission, p.2; and TEC, draft rule determination submission, p.3.

92 NSW DNSPs, draft rule determination submission, p.2.

93 AER, draft rule determination submission, p.4.

94 AusNet Services, draft rule determination submission, pp.2-3; Energex, draft rule determination submission, p.2; and ENA, draft rule determination submission, p.2.

95 ENA, draft rule determination submission, p.4; and Ergon, draft rule determination submission, p.1.

4.5 Overview of the final rule

Having regard to the views of stakeholders, and having undertaken its own analysis and review, the Commission has determined that it should make a more preferable rule. The final rule is the same as the draft rule (subject to some minor drafting clarifications) and is similar in its intent to the amendments proposed by the COAG Energy Council and the TEC. However, the Commission has made a number of modifications to improve the application of the final rule and better promote the NEO.

A detailed comparison of the amendments proposed by the COAG Energy Council and TEC with the provisions of the final rule is set out in Table 4.1. The key features of the final rule discussed in this section are as follows:

- Creation of separate provision in the NER for a demand management incentive scheme and a demand management innovation allowance.
- Inclusion of principles based approach to guide the development and application of the scheme by the AER.
- Requirement for the AER to develop and publish the scheme and allowance in accordance with the distribution consultation procedures, by 1 December 2016.

The Commission's assessment of these aspects of the final rule, including the reasons why it considers these aspects better meets the NEO then the amendments put forward by the proponents, are outlined in the following sections.

4.6 Commission's analysis

4.6.1 Separation of the scheme and allowance

The only component of the AER’s previous DMEGCIS is the innovation allowance. As noted previously, this has been provided to the businesses as an ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period. In this sense, the DMEGCIS developed and applied by the AER under the previous arrangements essentially operated as a research and development fund to encourage the businesses to conduct research and investigation into innovative techniques for managing demand. The AER did not develop or apply a demand management incentive scheme under the former provisions in the NER.

In line with the amendments proposed by the proponents, the final rule makes specific provision for an innovation allowance in the NER and separates this from the incentive scheme by including separate provisions for the scheme and allowance mechanism. This will allow for the clear articulation of the objective of each component of the demand management incentive mechanisms. It should also address concerns identified by the proponents and stakeholders that there has been some confusion around the

DMEGCIS, due to the AER having developed and applied an innovation allowance, rather than an incentive scheme.

The Commission considers that the separation of the provisions for the incentive scheme and the innovation allowance will provide greater clarity to the AER, and to stakeholders, regarding the purpose of, and arrangements supporting, each component of the broader mechanism.

4.6.2 Principles based approach

The previous DMEGCIS arrangements were intended to provide the AER with a tool to balance the incentives for distribution businesses to make efficient expenditure and investment decisions, including to pursue or procure demand management when it is efficient to do so. The previous arrangements therefore provided the AER with discretion on whether or not to establish and implement a DMEGCIS. Once the AER decided to establish a DMEGCIS, the rules were not prescriptive on how the scheme should operate, other than to specify a number of principles and factors that the AER must have regard to in designing and implementing a scheme.[96]

To date, the AER has chosen to apply the DMEGCIS in a limited manner. While a number of stakeholders believe that the lack of an effective scheme is due to there being limited guidance in the rules, the Commission understands that the AER has been reluctant to make any material changes to its current scheme while various reviews (the Power of Choice review, for example) have been ongoing.

In line with the general approach proposed by the COAG Energy Council and TEC, the final rule utilises a principles based approach to the development and application of the scheme and allowance. This approach avoids being too prescriptive and reflects the differing methods available to incentivise demand management as well as the different circumstances in which it may be necessary to do so – if the rules are too specific, then it may constrain the AER in its development and application of the scheme and allowance mechanism. This could potentially result in an inflexible or ineffective scheme or allowance being developed and potentially applied to the businesses.

A principles based approach will help to address some of the ambiguities identified by the proponents and clarify the application of the both the scheme and allowance. As discussed in the next chapters, the principles are sufficiently detailed to help guide the AER's development of the scheme and allowance, while allowing enough flexibility for the AER to be able to adapt the scheme and allowance to each business and over time as circumstances require. It will also provide appropriate accountability and transparency, which will help to provide certainty for stakeholders and confidence that the outcomes of the scheme and allowance are in the best interests of consumers.

This approach is also consistent with that taken by the Commission in the 2012 economic regulation of network service providers rule change requests. Providing the AER with greater discretion in how it undertakes its role was a key theme running

96 The objectives are discussed further in Chapter 5.

throughout the network regulation final rule, reflecting the Commission's view that the NER should be as flexible as possible in order to accommodate a range of different futures. To help guide the AER in how it exercised that discretion, the final rule for those rule changes introduced an objective and set of principles which the AER was required to have regard to when developing and applying the capex sharing scheme (one aspect of the network regulation final rule).

The details of the objective and principles for the scheme and allowance mechanism are discussed further in Chapters 5 and 6 respectively.

4.6.3 Requirement to develop and apply

In contrast to the previous rules which provided the AER with discretion to both develop and apply a DMEGCIS, the final rule requires the AER to develop a scheme and allowance, while providing it with the discretion to apply these to the distribution businesses.

Introduction of a requirement for the AER to develop a scheme and allowance will provide greater certainty to the distribution businesses around what these would look like and how they might operate if they were to be applied. It will also help to address the TEC's concern that the shortcomings identified with the current DMEGCIS were reflective of the AER having not used its full discretion in applying the current clause 6.6.3.

This approach will necessitate the AER considering, in some detail, whether the broader incentive regulation framework in Chapter 6 of the NER is providing distribution businesses with the appropriate incentives to pursue efficient demand management options. This should assist the AER in tailoring the scheme and allowance to individual distribution businesses if appropriate. Transparent and relatively predictable arrangements will help the businesses to prepare their proposals for the next round of regulatory determinations.

If the AER considers that the other incentive schemes, control mechanism and regulatory obligations applicable to a particular distribution business are adequate to balance the incentives between investment in network and non-network options, it may choose not to apply the scheme. That is, the Commission expects the AER would apply the scheme where it considers that there is a gap in these arrangements that could result in a bias towards network investment where a non-network option could be a more cost efficient solution. Examples of where a gap may occur that were raised by stakeholders include where a business is operating under a price cap and where there are broader market benefits to be gained from a non-network options that the DNSP does not have an incentive to factor into its decision.

The external environment may also influence the AER’s decision on whether to apply the scheme. For example, if consumers respond to well-designed network price signals, then there may be less need to provide incentives to balance network and non-network options.

The Commission expects that the decision whether to apply the incentive scheme and innovation allowance to a distribution business will be outlined and consulted on in the AER's Framework and Approach process for each business. This allows distribution businesses and other stakeholders an opportunity to provide input on whether the scheme and allowance should be applied and if so, how it should be applied.

The Commission notes that the AER already provides an innovation allowance under Part A of its current DMEGCIS. Mandating the development of an allowance mechanism under the final rule is therefore unlikely to be administratively burdensome. In addition, while the AER is likely to incur some administrative costs to develop the new scheme and allowance mechanism, the Commission does not consider these costs will exceed the expected benefits of developing and applying these measures.

The optional application of the scheme and allowance promotes flexibility and adaptability in the regulatory arrangements. It reflects the intent of the scheme and allowance as tools which are available to the AER to help it balance the incentives between network and non-network investment. The Commission considers the AER is generally best placed to determine which of the measures and mechanisms available to it should be used to encourage efficient investment and expenditure decisions.

4.6.4 Development of guidelines

The COAG Energy Council proposed to require the AER to develop guidelines for the DMIS. These would set out how incentive payments would be determined, including guidance on the calculation of benefits available for reward and the calculation of lost profits to be compensated. The AER would also be required to develop guidelines for the DMIA. TEC's proposed amendments did not include an equivalent provision; however, in its submission to the draft rule determination, the TEC considered that guidelines should apply.

To provide greater certainty around how the scheme and allowance will be utilised, the Commission considers there is merit in the AER setting out its approach to the development and application of the scheme and allowance mechanism. This will include setting out details on the methodologies used to calculate incentive rewards under the DMIS, and its approach to determining the size of the DMIA provided to the distribution businesses. Guidance of this type will complement the principles based approach to the scheme and allowance by tempering the discretion afforded to the AER in developing and applying the scheme and allowance, and creating some accountability. It will also provide stakeholders with an opportunity to engage with the AER to determine how the DMIS and the DMIA will operate.

However, the Commission does not consider it is necessary to include in the NER an explicit requirement for the AER to prepare guidelines to support the application of the scheme or allowance mechanism.

In line with proposed amendments, the final rule requires the AER to develop and publish the scheme and allowance mechanism in accordance with the distribution consultation procedures.[97] As part of this process, the AER is required to consult with stakeholders on the design of the scheme and, at a minimum, publish a decision that sets out the scheme (which include methodologies and proposed calculations), the reasons for the scheme and a summary of each issue raised by stakeholders in respect of the scheme, including the AER's response to each issue.[98] The same process will need to be followed for the innovation allowance.

The outcome of this process will be a document that sets out the incentive scheme, and the innovation allowance, including an explanation of how both of these will work. The Commission then expects the AER will explain how the scheme and allowance will be applied to individual businesses as part of the Framework and Approach process for each distribution business.[99] A separate guideline is therefore unnecessary as the relevant information will be included in these documents.

In addition, the Commission has had regard to the frameworks for other incentive scheme frameworks in the NER. The other schemes do not require the AER to develop guidelines for their application, aside from the CESS.

4.6.5 Applicable demand management projects

Currently, distribution business may seek funding for both tariff or non-tariff based demand management projects under the innovation allowance (Part A of the previous DMEGCIS). However, they may only seek to recover any revenue foregone as a result of having implemented a non-tariff based demand management project funded by the innovation allowance (Part B of the previous DMEGCIS).[100]

In its rule change request, the COAG Energy Council proposed to limit the incentive scheme to non-tariff based demand management projects only. In contrast, the TEC

97 The distribution consultation procedures are set out under clause 6.16 of the NER.

98 The distribution consultation procedures allow the AER to publish issues, consultation and discussion papers, and to hold conferences and information sessions, in relation to the scheme, as it considers appropriate. See NER clause 6.16(d).

99 The AER's framework and approach (F&A) paper is the first step in a process to determine efficient prices for electricity distribution services. It provides the AER with the opportunity to set out, among other things, its initial position on which services it will regulate for a distribution business for the next regulatory control period. It also allows the AER to set out how it proposes to apply the relevant incentive schemes. The F&A process facilitates early public consultation and assists distribution businesses prepare regulatory proposals.

100 As explained in section 1.2.2, the AER has developed the current DMEGCIS in two parts: Part A is an innovation allowance that provides funding to distribution businesses to trial innovative demand management and embedded generation connections projects; Part B then provide distribution businesses with a payment designed to address the impacts that certain forms of control (such as the price cap) may have on a distribution business’s incentives to undertake efficient demand management. It allows the distribution businesses to recover foregone resulting from a reduction in the quantity of energy sold directly attributable to demand management projects or programs approved under Part A of the scheme.

proposed that both tariff and non-tariff based demand management projects be included within the scope of the scheme.

The Commission notes that the AEMC's recent distribution network pricing arrangements rule change will be implemented in all jurisdictions by July 2017. From this time, all distribution businesses will be required to set network tariffs which reflect the business' efficient costs of providing services to each consumer.[101] It also provides a framework to require businesses to develop network tariff structures which appropriately incentivise efficient demand side responses by consumers. This includes, for example, shifting some consumption to lower cost off-peak times or by installing technologies that help reduce their peak demand.

The Commission does not consider it is appropriate for the scheme to be used to provide additional financial incentives for distribution businesses to undertake demand management measures which are already required to be implemented under the NER, or any other obligations relevant to demand management, to be part of the scheme - for example, cost reflective network tariffs or initiatives to efficiently connect embedded generators.

Consistent with the application of the AER's previous DMEGCIS, the final rule allows both tariff and non-tariff based demand management projects to be included within the scope of the innovation allowance, subject to the AER's development of the allowance taking into account the objective and principles.

In addition, the final rule does not include the connection of embedded generators within the scope of the innovation allowance. This differs from the previous DMEGCIS rules in Chapter 6 of the NER and the proponent's rule change requests. The AEMC has recently amended Chapters 5 and 5A of the NER to assist in the efficient and transparent connection of embedded generation.[102] As a result of these changes, the Commission does not consider it is appropriate or necessary to provide additional funding to incentivise the efficient connection of embedded generation. This matter is discussed further in section 6.4.

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101 There are a number of other principles that distribution businesses must comply with in developing their tariffs, including the impact on consumers of changes in network prices, and also any jurisdictional pricing obligations imposed by state or territory governments.

102 AEMC 2013, Connecting Embedded Generators, Rule Determination, 27 June 2013, Sydney; AEMC 2014, Connecting Embedded Generators Under Chapter 5A, Rule Determination, 13 November 2014, Sydney.

5 Demand management incentive scheme

This chapter sets out the Commission's views in relation to the matters specific to the demand management incentive scheme. In considering these matters, the Commission has had regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- sections 5.1 describe the key amendments as proposed by the proponents in relation to the demand management incentive scheme;
- section 5.2 summarises stakeholder responses to the consultation paper and draft rule determination;
- section 5.3 provides a description of the final rule in relation to the demand management incentive scheme; and
- sections 5.4 and 5.5 then provide a summary of the Commission's analysis of the relevant issues and amendments, and set out its conclusions on these matters.

5.1 Proponents' views

5.1.1 DMIS objective and principles

As noted in the previous chapter, the proponents both proposed a principles based approach to the development and application of the incentive scheme and innovation allowance.

The objectives and principles as specified by the COAG Energy Council and the TEC in the consolidated rule change request are set out in Table 5.1. The proponents' views in relation to these are then set out below.

Table 5.1 Comparison of the objectives and principles for the demand management incentive scheme proposed by the proponents

COAG Energy Council proposal	TEC proposal
Objective	
To provide a mechanism which appropriately incentivises distribution businesses to implement efficient non-tariff based demand management projects, where the reward is justified by net benefits and the incentives rewarded are derived from payments of foregone profits and a combination of market benefits and avoided or deferred network costs.	To provide an appropriate return to the network businesses for demand management projects which deliver a net cost saving to their consumers.
Principles	
The scheme must have the following principles: 1. recognise the need to incentivise networks towards implementing efficient DSP over the long term and not just the forthcoming regulatory control period; 2. align, to the extent possible, payment of any reward available under the scheme with the timing of benefits in order to smooth the bill impact on consumers; 3. be simple to apply, such that the incentive design should be easy to understand, implement and administer; 4. contribute to achieving a material change that is to be reported in the amount of efficient DSP in the market; 5. non-distribution network benefits under this scheme should only be available where the distribution business has been unable to negotiate a	The DMIS must be applied in a manner consistent with the following principles: 1. demand management projects should address (current and/ or anticipated) network issues in order to qualify for inclusion in the DMIS, noting that potential network issues include network supply capacity, reliability, asset replacement and changing demand or local generation patterns; 2. expenditure on demand management projects approved under this scheme must be treated equitably with other network expenditure approved under the determination process; 3. notwithstanding the above, consideration of funding for qualifying demand management projects shall recognise the need to incentivise network demand management over the long term, and not just for the forthcoming regulatory period; 4. payments to consumers or other providers of demand management services under the scheme should reflect consideration of timing to smooth

COAG Energy Council proposal	TEC proposal
share of these benefits from the beneficiary; 6. the share of non-distribution network benefits available for reward for pursuit of demand management projects should be no more than 30 per cent of non-distribution network market benefits created by the project (the actual percentage may vary by business and by time where the AER considers different levels of incentive are required for the distribution business to pursue efficient demand side participation); and 7. as a further safeguard from potentially excessive rewards to distribution businesses, the non-distribution network related market benefits should only be available to the distribution business when they are substantiated and realised.	the bill impact on consumers; 5. the scheme design should be as simple as practicable to apply, such that it is easy to understand, implement and administer for all market participants; and 6. the scheme should contribute to achieving a material change that maximises in the amount of efficient demand management in the market.[103]

103 Although not included as (or as part of) a principle, the TEC proposed that the share of non- network market benefits available for reward for pursuit of demand management projects should be no more than 50 per cent of the non-network market benefits created by the project.

DMIS objective

In its rule change request, the COAG Energy Council proposed to introduce an explicit objective for the demand management incentive scheme. This was to provide greater certainty and clarity for distribution businesses with regard to the purpose of the scheme, and the circumstances under which businesses may earn a return on demand management projects approved under the scheme.[104]

The TEC also proposed to introduce an explicit objective for the demand management incentive scheme in the rules. It considered that the objective should clarify the purpose of the scheme, and therefore proposed that it be to provide an appropriate return to the network businesses for demand management projects which deliver a net cost savings to their consumers.[105]

DMIS principles

The principles specified by the COAG Energy Council and the TEC are based on the recommendations made by the AEMC's Power of Choice review. In light of this, the majority of discussion in the rule change requests regarding principles is limited to the areas of difference between the rules proposed by the proponents, and the recommendations made by the AEMC in that review.

In this context, both the COAG Energy Council and the TEC proposed to introduce an additional principle that would require the AER to provide for long term incentives under the DMIS. The COAG Energy Council considered this would recognise that some demand management projects might incur costs and deliver benefits across multiple regulatory control periods and that it was important that such projects, where they deliver an overall benefit to the market, were not discouraged from being implemented.[106]

5.1.2 Rewards under the scheme

A common feature of both rule change requests was explicit recognition in the rules of the ability for the AER to include two forms of reward under the DMIS:

- a reward based on a proportion of the net market benefits (or avoided or deferred network costs) produced by a demand management project; and
- a reward as compensation for any lost revenues or profits that occur as a result of reduced demand from implementing a demand management option, where appropriate.

The proponents' views in relation to each form of reward are set out below.

104 COAG Energy Council rule change request, p.5.

105 TEC rule change request, p.7.

106 COAG Energy Council rule change request, p.6; TEC rule change request, p.8.

Reward for non-network market benefits

In its rule change request, the COAG Energy Council considered the current inability of distribution businesses to secure a proportion of the benefits created by their demand management projects across the supply chain, amounted to a market failure.[107] It considered this was likely leading to the inefficient under-provision of such projects which was not in the long term interests of consumers. To address this issue, it proposed an explicit provision in the rules allowing the AER to apply an incentive based on the broader supply chain benefits created by demand management projects.

In addition, the COAG Energy Council considered that the level of reward available to the businesses for demand management projects should be consistent with those available under other incentive schemes in Chapter 6 of the NER (that is, for capital and operating expenditure) and commensurate with any additional level of risks involved in developing such projects. It therefore proposed that the rules include a requirement for the rewards for non-network related market benefits to be capped at no more than 30 per cent of those benefits. It considered a cap, coupled with the requirement that demand management projects generate net benefits before financial rewards can be secured (enacted through the DMIS objective), would help to protect consumers from the provision of excessive rewards to distribution businesses under the scheme.

Similarly, in its rule change request, the TEC noted that a major shortcoming of the AER's current DMEGCIS was the lack of a sufficient financial incentive for networks to undertake demand management projects as an alternative to investing in network capex. It therefore also proposed an amendment to the rules to clarify that the DMIS permit distribution businesses to retain a share of the non-network related market benefits created by a demand management project.

The TEC also proposed that the rules specify two conditions under which the businesses be allowed to retain a share of the non-network market benefits of demand management activities: first, the distribution business must have made a material contribution to the demand management; and second, it must be unlikely that the demand management activity would have been delivered without the support of the distribution business. In order for these benefits to be equitably shared with consumers, the TEC proposed that the rules specify a cap of 50 percent of the share of non-network related market benefits to be retained by the distribution businesses.[108][109]

107 COAG Energy Council rule change request, p.5.

108 ibid, p.8.

109 In its submission to the consultation paper, the TEC noted that, despite having proposed a 50 percent cap on the market benefits to be retained by the businesses, was comfortable with a lower cap of 30 percent, as proposed by COAG. See TEC, consultation paper submission, pp.8-9.

Reward for foregone revenue or foregone profit

The COAG Energy Council noted that Part B of the DMEGCIS was introduced by the AER to address the potential impacts of demand management projects on the revenues of distribution businesses regulated under a weighted average price cap.[110]

However, while it acknowledged the broad intent of the revenue based payment, it considered that profit based compensation would better recognise that demand management options can drive costs lower as well as revenues. As a consequence, distribution businesses may not necessarily be worse off where they experience loss in revenue from implementing a demand management project.[111]

To guard against over compensation, the COAG Energy Council therefore proposed that the rules require the AER's incentive scheme to include a reward as compensation for any lost profits that occur as a result of reduced demand from implementing a demand management option.[112]

The TEC considered that, in order to treat demand management equally with other network expenditure, the rules must ensure that the DMIS allows distribution businesses to recover any revenue lost as a consequence of it undertaking approved demand management projects. The TEC considered it was appropriate to allow for the recovery of foregone revenue rather than foregone profit (as proposed by the COAG Energy Council) on the basis that the rules should be concerned to limit network costs and prices, rather than network profits.[113]

5.2 Stakeholder views

5.2.1 Submissions to the consultation paper

In submissions to the consultation paper, stakeholders generally supported the proposed introduction of a high level objective and set of detailed principles in the rules. It was generally considered that additional clarity would assist the AER to design and apply an effective demand management incentive scheme. There was also general recognition that a principles based approach was consistent with other incentive schemes in the NER.[114] Energex considered it was appropriate for the AEMC to consult on the merits of each of the proposed principles further.[115]

The majority of submissions considered that a scheme which allows distribution businesses to capture a proportion of non-network related market benefits delivered by a demand management project could increase investment in these projects. For

110 COAG Energy Council rule change request, p.7.

111 ibid.

112 ibid.

113 TEC rule change request, p.8.

114 See section 4.3 for further views from stakeholders on the proposed objectives and principles.

115 Energex, consultation paper submission, p.3.

example, Origin Energy considered that demand management should have direct financial incentives that are comparable to those associated with network investment, and that supply chain benefits should be taken into account when allocating rewards.[116] Ergon Energy was of the view that where a demand management project creates long term value for other market participants, a share of this longer term value should be shared, thereby enabling more demand management investment.[117]

In contrast, GDF Suez Australia was firmly opposed to this proposal. It stated that under no circumstances should market benefits be included as this would further distort an unnecessary scheme. It considered that customer choice and a retailer led approach was the effective and economically efficient way forward.[118]

In relation to the proposals to mandate in the rules a cap on the proportion of non-network related market benefits which could be retained by the distribution businesses, stakeholders generally considered this should be left to the AER to determine. There was also general recognition among stakeholders that particular emphasis needed to be placed on the methodology for, and process to be followed when, calculating the non-network related market benefits created by a demand management project. Origin Energy considered that consistency across regulatory methods for determining supply chain benefits was appropriate, noting the RIT-D and proposed demand side response mechanism as examples.[119]

Stakeholders were generally supportive of the retention and codification of a foregone revenue/profit component of the incentive scheme. While stakeholders acknowledged that this component would not be relevant to distribution businesses regulated under a revenue cap, there was nevertheless general agreement that the rules for the DMIS should not be framed to assume one form of regulation over another. For example, NSW DNSPs stated that, while a foregone revenue component was not necessary under a revenue cap, it should nevertheless be codified to provide the AER with flexibility to incorporate it into the scheme in the event the form of control changes in subsequent regulatory determinations.[120]

The AER also acknowledged that foregone revenue measures were no longer required, given the application of revenue caps to the distribution businesses. It preferred being provided with discretion to consider the appropriateness of these matters should there be any future changes to control mechanisms.[121]

116 Origin Energy, consultation paper submission, p.2.

117 Ergon Energy, consultation paper submission, p.6.

118 GDF Suez Australia, consultation paper submission, p.5.

119 Origin Energy, consultation paper submission, p.2.

120 NSW DNSPs, consultation paper submission, p.8.

121 AER, consultation paper submission, p.9.

5.2.2 Submissions to the draft rule determination

Stakeholders broadly supported the draft rule with respect to the incentive scheme. The majority of stakeholders did not offer comments on the objective of the scheme, but suggested minor changes to the principles to add more prescription. AGL, GDF Suez Australia and Snowy Hydro did not support the draft rule. EnergyAustralia expressed concerns in relation to the draft rule, but did not go as far as to not support it.

AusNet Services considered that an incentive scheme that enables distribution businesses to share any market benefits resulting from non-network solutions by way of financial rewards, would encourage the adoption of efficient non-network options. This will help distribution businesses prepare for the future where non-network options will become more important, as new technologies will make them suitable and affordable substitutes for network solutions.[122]

DMIS objective

The NSW DNSPs were the only stakeholder to comment on the objective of the incentive scheme. The NSW DNSPs considered that the drafting of the objective could result in a narrow application of the scheme that may effectively exclude demand management projects that involve some expenditure on network assets. For example, they were concerned that they may not be able to undertake load control that involved distribution assets including ripple injection plant at zone substations and switches at consumer premises to control that consumer's load.[123]

DMIS principles

The South Australia Department of State Development made a number of comments in relation to the DMIS principles, including that:

- an additional principle should be included to provide that financial rewards under the incentive scheme are only made available when the project savings are actually substantiated and realised, due to a concern that principle two does not go far enough to ensure this;
- an additional principle should be included to provide that where the AER takes into account net economic benefits, DMIS should provide a transparent methodology about how the value of these benefits is to be determined; and
- principle four should recognise that the incentive should not include potential fees and charges that a distribution business can recover as a result of a demand management project.[124]

122 AusNet Services, draft rule determination submission, p.2.

123 NSW DNSPs, draft rule determination submission, p.4.

124 The South Australia Department of State Development, draft rule determination submission, pp.1-2.

ENA considered that principle seven should be flexible enough to allow the AER to consider any element of the regulatory framework that may be interrelated to the operation of the incentive scheme in terms of affecting incentives for distribution businesses to undertake demand management.[125]

Rewards under the scheme

Stakeholders also expressed mixed views in relation to the design of financial rewards under the incentive scheme.

Energex and ENA called for the rules to explicitly provide clarity around the recovery of any foregone revenue or profit that occurs from any reduction in demand as a result of a demand management project.[126] However, the AER and EnergyAustralia considered that the AER is best placed to consider the particular design of financial rewards as this recognises that financial incentives can be designed in a number of different ways.[127]

Reporting requirements

The South Australia Department of State Development considered that the final rule should require the AER to monitor and report on the effectiveness of the incentive scheme on an annual basis and that distribution businesses should be required to report on projects funded under the incentive scheme.[128] They also considered, together with the TEC and PIAC, that distribution businesses should be required to report on demand management projects pursued under the incentive scheme.[129]

5.3 Overview of the final rule

The final rule gives the AER the power to implement a DMIS of its own design, having regard to a demand management incentive scheme objective and taking into account certain principles. Box 5.1 sets out the DMIS objective and principles.

125 ENA, draft rule determination submission, p.3.

126 Energex, draft rule determination submission, p.2; and ENA, draft rule determination submission, p.1.

127 AER, draft rule determination submission, p.3; and EnergyAustralia, draft rule determination submission, p.1.

128 The South Australia Department of State Development, draft rule determination submission, p.2.

129 The South Australia Department of State Development, draft rule determination submission, p.2; PIAC, draft rule determination submission, p.2; and TEC, draft rule determination submission, p.6

Box 5.1 Demand management incentive scheme objective and principles

Objective[130]

The objective of the demand management incentive scheme is to provide distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management (the demand management incentive scheme objective).

Principles[131]

In developing and applying any demand management incentive scheme, the AER must take into account the following:

1. the scheme should be applied in a manner that contributes to the achievement of the demand management incentive scheme objective;

2. the scheme should reward distribution businesses for implementing relevant non-network options that deliver net cost savings to retail customers;

3. the scheme should balance the incentives between expenditure on network options and non-network options relating to demand management. In doing so, the AER 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;

4. the level of the incentive:

   (i) should be reasonable, considering the long term benefit to retail customers;

   (ii) should not include costs that are otherwise recoverable from any another source, including under a relevant distribution determination;

   (iii) may vary by distribution business and over time;

5. penalties should not be imposed on distribution businesses under any scheme;

6. the incentives should not be limited by the length of a regulatory control period, if such limitations would not contribute to the achievement of the demand management incentive scheme objective;

130 NER Clause 6.6.3(b).

131 NER Clause 6.6.3(c)(1)-(7).

7. the possible interaction between the scheme and:

    (i) any other incentives available to the distribution businesses in relation to undertaking efficient expenditure on, or implementation of, relevant non-network options;

    (ii) particular control mechanisms and their effect on a distribution business' available incentives referred to above; and

    (iii) meeting any regulatory obligation or requirement.

5.4 Commission's analysis

5.4.1 DMIS objective

The demand management incentive scheme objective set out in the final rule requires that the scheme must aim to provide distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.

The DMIS objective refers to 'non-network options'. A non-network option is defined in Chapter 5 of the NER as a means by which an identified need can be fully or partly addressed other than by a network option. An 'identified need' is the objective that a network business seeks to achieve by investing in the network. The use of 'non-network option' in the objective therefore reflects that only projects which are intended to address an identified issue on the network are applicable for inclusion in the scheme. The fact that a non-network option can *fully* or *partly* address an identified need means that a non-network option could include an option that involves some expenditure on a network asset.

In addition, requiring that the scheme incentivise efficient expenditure on non-network options that are 'related to demand management' recognises that the AER has some flexibility to determine which projects are eligible for inclusion in the scheme, taking into account the principles (specifically, principle seven). It also recognises that demand management options are a subset of non-network options, and may change over time.[132] The AER therefore has the discretion to determine the extent and scope of the incentives.

The DMIS objective also refers to 'efficient expenditure'. Importantly, the demand management incentive scheme developed by the AER should not skew the incentives on distribution businesses to pursue relevant non-network options at the expense of more efficient network options. Rather, it should be applied in order to balance the incentives on distribution businesses to undertake efficient expenditure, where the

132 Expenditure on embedded generation to avoid funded augmentations can fall within the scope of 'non-network options related to demand management'.

AER considers the regulatory framework is not providing a level playing field between network and non-network options.

The demand management incentive scheme objective closely mirrors that which was proposed by the COAG Energy Council in its rule change request. However, the objective proposed by COAG Energy Council also contained explicit provisions in respect of the rewards to be included within the scheme, that is, those derived from payments of foregone profits and a combination of market benefits and avoided or deferred network costs. The Commission does not consider it appropriate for this detail to be included within the objective. However, how the value of the incentive is determined is a key component of the scheme and has been captured in principle three (discussed below).

While the Commission supports the TEC's view that the incentive scheme should provide an appropriate return to the network businesses for demand management projects which deliver net cost saving to their consumers, it also considers that this concept is better captured as a principle rather than an objective. This is because it provides guidance to the AER in respect of the design of the scheme rather than conveying what the scheme is aiming to achieve (see the discussion on principle two below).

The objective set out in the final rule is broadly consistent with the approach taken to the objectives of the other incentive schemes in Chapter 6 of the NER.

5.4.2 DMIS principles

The **first principle** clarifies that the incentive scheme should be applied in a manner that contributes to the demand management incentive scheme objective. As the obligation to develop a scheme already requires the development to be consistent with the objective, this principle clarifies that the application of the scheme by the AER must also contribute to the scheme objective.

The **second principle** concerns rewards. The scheme should reward distribution businesses for implementing relevant non-network options that deliver net cost savings to retail consumers. An incentive scheme is only effective if it changes the distribution business' behaviour and should only be applied where the change in behaviour delivers net cost savings to consumers. Requiring net cost savings to be delivered reflects that the benefits and savings to consumers from implementation of a relevant non-network option should be substantiated and realised. This principle captures the intent of the objective proposed by the TEC which focussed on the net benefits to consumers.

The final rule is not prescriptive with respect to how or when a distribution business should demonstrate net cost savings. The Commission considers that prescribing in the NER that a project's savings must be substantiated and realised before the incentive is applied could limit the AER's discretion to design the scheme as it might imply that the scheme can only be applied on an ex post basis. Therefore, the Commission considers that it is appropriate that the AER have discretion to consider how and when rewards are to be applied in its design of the scheme.

The **third principle** concerns the scheme generally. The scheme should balance the incentives between network and non-network options in relation to demand management. It may also 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 first component of the principle recognises that the scheme must encourage the distribution businesses to make decisions which lower overall total system costs, irrespective of the type of expenditure or investment involved. The second part of the principle recognises that incentive rewards can be designed in different ways, and that one possible method of determining the value of the scheme could be through consideration of the net economic benefits delivered across the supply chain by a demand management option.

The **fourth principle** concerns the level of the incentive. The level of the incentive should be reasonable, considering the long term benefit to retail customers. The level should not include costs that are otherwise recoverable from any another source included in the relevant distribution determination, including fees and charges that a distribution business can recover as a result of a demand management project. The incentives may also vary by distribution business, and over time. This recognises that the reward should broadly align with retail customers' willingness to pay for any increases in costs resulting from implementation of the scheme, and therefore should not be excessive. It also recognises that distribution businesses should not be rewarded twice for undertaking efficient expenditure on relevant non-network options.

The **fifth principle** concerns penalties. Penalties should not be imposed on distribution businesses under this scheme. This recognises that the scheme provides the AER with a tool to be able to better balance the incentives between network and non-network investment. Penalising the distribution businesses risks the businesses avoiding expenditure on these projects altogether.

The **sixth principle** concerns the timeframe over which an incentive can be applied. Incentives should not be limited by the length of a regulatory control period if such limitations would not contribute to the achievement of the scheme's objective. This recognises that projects may incur costs, and deliver benefits, across multiple periods and can be long term, as identified by the proponents. Further, it avoids distorting incentives as a result of having a five year regulatory control period, similar to the EBSS.

The **seventh principle** concerns the interaction of the scheme with other incentive schemes, control mechanisms and regulatory obligations. In developing and implementing the scheme, the AER should take into account possible interactions with any other incentives available to the distribution businesses in relation to undertaking efficient expenditure on, or implementation of, non-network options. This recognises that all incentive schemes applied to a distribution business need to work together in a way that allows each incentive to work as intended. In applying the DMIS to a distribution business, the AER should take into account it's interactions with, and impacts on the intent of, other incentives applied to the business.

In addition, the AER should consider the interaction between the scheme and particular control mechanisms and their effect on a distribution business' available incentives. This component of principle seven recognises that particular control mechanisms will influence the strength of the incentives on distribution businesses to pursue demand management options, and so will likely also influence the scope and design of the incentive scheme by the AER.[133]

Principle seven also requires the AER to consider the possible interaction between the scheme and the requirement to meet any regulatory obligation or requirement. This component recognises that the DMIS is not intended to reward a distribution business for implementing an efficient demand management solution where it is already required to do so under the rules or by any other regulatory requirement or obligation, for example, the new distribution network pricing arrangements.[134] An alternative approach would be to include in the final rule a requirement on the AER to explicitly exclude tariff based demand management projects from the scope of the scheme. However, the Commission considers that requiring the AER to take into account principle seven in developing and applying the scheme provides a more flexible approach.

The Commission considers that principle seven is broad enough to allow the AER to consider the interaction between the incentive scheme and all other relevant elements of the regulatory framework which may impact on the incentive to undertake demand management projects. The Commission acknowledges ENA's concerns in relation to this principle,[135] but considers that limiting the AER's consideration to other incentive schemes, control mechanisms or regulatory obligations that are relevant to the design of the DMIS is appropriately broad, as these are the elements of the regulatory framework that are interrelated to the design of DMIS.

The Commission considers that this set of principles will guide the AER in developing and applying an incentive scheme which is effective in encouraging efficient decision making by the distribution businesses. This will lead to lower overall total system costs and better outcomes for consumers.

The provision of principles in the final rule promotes flexibility and adaptability by guiding the AER's consideration of specific elements of the scheme, including rewards for market benefits, having regard to developments in the market and regulatory arrangements, and to the different characteristics of the businesses. It also provides

133 For example, distribution businesses regulated under a price cap may have reduced incentives to use demand management because reductions in demand result in reductions in the maximum regulated revenue that the business is permitted to earn.

134 The introduction of cost reflective network tariffs would not be eligible for payment of an incentive reward under a DMIS on the basis that the new distribution network pricing rules require all distribution businesses to develop network tariffs which better reflect their cost drivers.

135 Outlined in 5.2.2 above.

greater certainty and transparency to the distribution businesses and other market participants regarding the purpose and operation of the scheme.

In its submission to the draft rule determination, the South Australia Department of State Development proposed an additional principle which provides that where the AER takes into account net economic benefits, the DMIS should provide a transparent methodology about how the value of those benefits is to be determined.

The Commission notes that the final rule does not explicitly require the AER to set out a methodology in relation to how the value of net economic benefits is determined. However, the Commission expects that the AER will outline its approach to considering and/or determining net economic benefits in its decision document that sets out the DMIS as this is a key aspect of the scheme. This view is consistent with comments that the AER made in its submission to the draft rule determination.[136]

There are a number of other principles and factors included in the consolidated rule change request which the Commission has determined not to include in the final rule. The Commission's reasons for not introducing these are set in Table C.1 in Appendix C.

5.4.3 Rewards under the scheme

Currently, the only benefits that distribution businesses are able to derive from implementing demand management projects relate to the cost savings from deferred or avoided distribution network expenditure. Demand management projects will typically also create benefits at other points of the supply chain, such as avoided generation costs and avoided investment in the transmission network.

The foregone revenue component of the current DMEGCIS developed and applied by the AER under the existing rules is intended to address the potential impacts of demand management projects on the revenues of distribution businesses regulated under a weighted average price cap. These businesses are able to recover, for non-tariff based demand management projects, revenues that may have been lost from a lower quantity of energy sold arising as a consequence of the project.

A common feature of both rule change requests was explicit recognition in the rules of the ability for the AER to include two forms of reward under the incentive scheme: a reward based on a proportion of the net market benefits (or avoided or deferred network costs) produced by a demand management project; and a reward as compensation for any lost revenues or profits that occur as a result of reduced demand from implementing a demand management option.

The final rule gives the AER the power to implement a demand management incentive scheme of its own design, taking into account certain principles. Importantly, the design of the financial rewards under the scheme (that is, the value of the incentive) could be approached in a range of ways. This is recognised in principle three which

136 AER, draft rule determination submission, p.4.

clarifies that the AER may take into account the delivery of net economic benefits delivered to all those who produce, consume and transport electricity in the market when developing the scheme.

The Commission notes that ENA and Energex called for greater clarity around the recovery of any foregone revenue or profit that occurs from any reduction in demand from a demand management project. The recovery of foregone revenue or profits is one of the ways that the AER could design financial rewards under the scheme, taking into account the nature of the control mechanism that applies to each distribution business. The Commission expects that the AER will provide greater clarity on financial rewards as it designs the scheme. However, the Commission does not consider it necessary to add prescription with respect to particular financial rewards in the final rule.

The Commission acknowledges the concerns of the proponents and stakeholders that the previous rules were not clear on whether the AER was able to develop an incentive scheme under the rules which would allow distribution businesses to retain a share of the non-network related market benefits delivered by a demand management project. As noted above, the Commission considers that this concern is addressed by the third principle.

The Commission also acknowledges the proposals by the proponents to include in the rules a cap on the proportion of non-network related market benefits delivered by a demand management project. The COAG Energy Council and the TEC suggested maximum caps of 30 per cent and 50 per cent of the non-network related market benefits, respectively.

The Commission considers it is appropriate for the AER to determine the sharing ratio, taking into account that the level of the incentive should be reasonable, considering the long term benefit to retail customers (principle four). This approach is consistent with the other incentive schemes in Chapter 6 of the NER.

5.4.4 Reporting requirements

The final rule places no explicit obligations on distribution businesses to report on the results of demand management projects pursued under the incentive scheme.

Distribution businesses will likely be required to report to the AER on either the expected outcomes, or actual outcomes of any demand management projects pursued under the scheme in order to receive their financial incentive. The exact form of those reports will depend on the nature and scope of the scheme developed by the AER. It would be inappropriate for the rules to determine these reporting requirements as it may inadvertently limit the AER's discretion in the design of the scheme. The Commission considered that it is not appropriate to limit the AER's discretion in this way and has determined not to include explicit reporting requirements.

In addition, as distribution businesses may engage third parties to provide them with demand management services, many of the projects pursued under the scheme may be commercial-in-confidence. As such, distribution businesses may be limited in relation to the information that they can report on publicly.

Further, distribution businesses are already required to report on demand management projects in their DAPR. The DAPR arrangements require distribution businesses to report on their demand management activities, including the non-network options considered in the past year, the actions taken to promote non-network proposals in the past year and their plans for demand management over the forward planning period (which is five years).[137]

Consequently, the Commission considers that in light of the above, no express obligations are necessary.

In relation to the South Australia Department of State Development proposal that the AER be required to report annually on the effectiveness of the incentive scheme, the Commission does not consider that this is appropriate, for similar reasons as outlined above. Further depending on the design of the scheme, it may not be feasible for the AER to report every year, as the scheme may be linked to the regulatory cycle, for example.

137 Schedule 5.8(l)(1)(i), (ii), (iii) of the NER.

6 Demand management innovation allowance

This chapter sets out the Commission's views about matters specific to the demand management innovation allowance.[138] In considering these matters, the Commission has taken into account the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 6.1 describes the key amendments as proposed by the proponents in relation to the demand management innovation allowance;
- section 6.2 summarises stakeholder responses to the consultation paper and draft rule determination;
- section 6.3 provides a description of the final rule in relation to these matters; and
- sections 6.4 and 6.5 then provide a summary of the Commission's analysis of the relevant issues and amendments, and set out its conclusions on these matters.

6.1 Proponents' views

6.1.1 DMIA objective and principles

In its rule change request, the COAG Energy Council stated that the rationale for the innovation allowance was focussed on providing a special/alternative source of funding for distribution businesses to experiment and trial innovative approaches to demand management and the connection of embedded generators. It considered that this recognised the approaches to demand management and the connection of embedded generation were highly uncertain with respect to their costs and benefits and were unlikely to be undertaken by distribution businesses in the absence of additional funding.[139]

Similarly, the TEC stated that while it considered that the innovation allowance was "grossly underutilised" by distribution businesses, the allowance nevertheless provided a source of income for innovative demand management projects that may otherwise be hard to justify on economic grounds alone, and was therefore worth retaining.[140]

The objectives as specified by the COAG Energy Council and the TEC in the consolidated rule change request are set out in Table 6.1. Neither the COAG Energy Council nor the TEC proposed the introduction of principles for the development or application of the DMIA.

138 The demand management innovation allowance mechanism is referred to in this final rule determination as the innovation allowance.

139 COAG Energy Council, Rule change request, pp.8-9.

140 TEC, Rule change request, p.8.

Table 6.1 Comparison of the objectives for the demand management innovation allowance proposed by the proponents

COAG Energy Council proposal	TEC proposal
The AER shall publish guidelines on the innovation allowance scheme for research and development activities related to DSP. The objective of the scheme is as follows, to provide incentives and funding for distribution businesses to undertake activities that will increase their knowledge regarding: • the ability of different approaches (both technology and pricing based) to achieve efficient demand reductions; • the efficient connection of embedded generators; • the costs of those approaches; and • their impacts (if any) on network systems operations.	The AER shall establish a demand management innovation allowance scheme for research and development activities related to demand management. The innovation allowance scheme shall provide funding for, and an incentive to, distribution businesses to undertaken activities that will increase their knowledge regarding: • the ability of different approaches (both technology and pricing based) to achieve useful and reliable demand reductions; • the costs of those approaches; and • their impacts (if any) on network systems operations.

6.1.2 Other issues

Size of the innovation allowance

The COAG Energy Council noted that to date, the innovation allowance has been small, totalling no more than $1 million a year for each distributor.[141] It also noted that a final report from the Productivity Commission had advocated for an increase in the size of the innovation allowance.[142] The COAG Energy Council contended that this increase was needed to fund trials of new time of use pricing structures and to calculate demand elasticity because both the AER and distribution businesses require more data and understanding of consumer responses in order to set appropriate cost reflective network tariffs.[143]

In relation to setting the size of the innovation allowance, the COAG Energy Council and the TEC considered it appropriate that the AER retain this discretion.[144]

Reporting requirements

In light of the fact consumers are funding the innovation allowance, the COAG Energy Council and the TEC considered that distribution businesses should be required to

141 COAG Energy Council, Rule change request, p.9.

142 Productivity Commission, Electricity Network Regulatory Framework -Draft Report, Melbourne, October 2012.

143 COAG Energy Council, Rule change request, p.9.

144 ibid and TEC Rule change request, p.14.

share their data, results and learnings with the AER, other distribution businesses, and the market more broadly (through publication of results).[145]

The COAG Energy Council contended that this would allow for shared learning and assist the AER in carrying out its regulatory functions. It was also considered important that the allowance is only utilised for activities not funded elsewhere and should also take into account similar trials being undertaken overseas to avoid duplication.[146]

Time limiting the innovation allowance

The COAG Energy Council anticipated that any innovation allowance should be time limited until such time as technology and knowledge evolved to a point where demand management options become business as usual.[147] In making any decision about the duration of the innovation allowance, the COAG Energy Council considered it appropriate that the AER retain this discretion.

6.2 Stakeholders' views

6.2.1 Submissions to the consultation paper

In submissions to the consultation paper, stakeholders generally supported the proposed introduction of a high level objective and design principles in the NER. It was generally considered that additional clarity would assist the AER to design and apply an effective demand management innovation allowance.

Level of the innovation allowance

Stakeholders noted that the relative size of the innovation allowance and the AER's strict time limits on the funding within a regulatory control period may have contributed to its lower uptake.[148] The TEC also noted that the current size of the DMIA would be sufficient if there was an effective incentive scheme operating alongside it.[149]

Stakeholders were generally supportive of the AER retaining its current role in determining the level and application of allowance, rather than it being a matter for NER specification.[150] The NSW DNSPs considered that a more meaningful level could

145 COAG Energy Council, Rule change request, p.9 and TEC, Rule change request, p.14.

146 COAG Energy Council, Rule change request, p.9.

147 ibid.

148 Ergon Energy, consultation paper submission, p.5; NSW DNSPs, Consultation paper submission, p.6.

149 TEC, consultation paper submission, p.8.

150 Energy Networks Association, Consultation paper submission, p3, Energex, Consultation paper submission, p.4.

be achieved if the AER was required to consult on its methodology for determining the size of the allowance.[151]

Citipower and Powercor suggested an amendment to the innovation allowance, whereby distribution businesses would be able to seek further funding above the capped amount, subject to AER approval of such initiatives.[152]

Reporting requirements

The majority of submissions considered that the sharing of data, results and learnings gained from use of the innovation allowance was an essential element of the scheme.[153] The ENA, in addition to other distribution businesses recognised that there may be some overlap with the distribution annual planning reporting and the demand side engagement strategy. However, given that the allowance is funded by consumers with the explicit goal of producing a 'public good', the ENA considered it appropriate for tailored reporting arrangements to be in place.[154]

Stakeholders recommended that the form of any additional reporting requirements be consulted on. For example, the NSW DNSPs suggested reporting through stakeholder workshops or working groups in order to provide maximum benefit and minimise duplication.[155]

Time limiting the innovation allowance

In relation to a question in the consultation paper seeking stakeholder feedback on whether the innovation allowance should be time limited, stakeholders generally considered this should be left to the AER to be determined. Stakeholders were supportive of a time-based measure, provided the timeframes and rules around funding were clearly defined so projects could be scoped without fear of funding shortfalls.[156]

Ergon Energy suggested that there should be consideration in the scheme about certainty of funding for projects that extend over a regulatory control periods, that is, funding for the entire project life.[157]

6.2.2 Submissions to the draft rule determination

As noted in section 4.4, stakeholders were generally supportive of the Commission’s principles based approach to the demand management innovation allowance outlined in the draft rule determination. The majority of stakeholders did not offer comments on

151 NSW DNSPs, consultation paper submission, p.7.

152 Citipower and Powercor, consultation paper submission, p.7.

153 Origin Energy, TEC, Ergon Energy

154 ENA, consultation paper submission, p.3.

155 NSW DNSPs, consultation paper submission, pp.7-8

156 Ergon Energy, consultation paper submission, p.6.

157 ibid, p. 5.

the objective or the principles of the allowance. Again, AGL, GDF Suez Australia and Snowy Hydro did not support the draft rule. EnergyAustralia expressed concerns in relation to the draft rule, but did not go as far as to not support it.

DMIA objective

The NSW DNSPs sought guidance on the objective and a number of the principles. Similar to its comments in relation to the objective of DMIS, the NSW DNSPs considered that the drafting of the objective could be narrowly interpreted and prevent distribution businesses from pursuing innovative demand management projects that resulted in consequential spending on network assets.[158]

ENA and Ergon Energy proposed that embedded generation connection projects should not be excluded from the innovation allowance. ENA considered that to exclude these projects may act to 'pick winners' and thereby stifle innovation.[159] Ergon Energy noted that renewable energy systems are likely to drive future network investment and thereby considered it appropriate that distribution businesses have access to funding to undertake research and development in relation to how to integrate these systems in a way that minimises network investment.[160]

DMIA principles

In relation to the principles, the NSW DNSPs had concerns in relation to the application and definition of the word 'innovative' and questioned how the uniqueness or novelty of a proposed project could be distinguished from businesses as usual. These businesses also had concerns that the word 'ongoing' could be interpreted as to exclude a distribution business from pursuing demand management projects that were temporary or short-term in nature.[161]

Distribution businesses were supportive of the discretion afforded to the AER to determine the value of any innovation allowance applicable to each business, but considered that more transparency is needed in relation to the methodology the AER will use to determine the size of the allowance.[162] NSW DNSPs called for the AER to develop a guideline that sets out the methodology for setting the level of the innovation allowance. It considered that this would provide greater transparency and regulatory certainty to market participants.[163]

Reporting requirements

Distribution businesses also expressed concerns in relation to the nature and scope of reporting requirements under the innovation allowance. They considered that the AER

158 NSW DNSPs, draft rule determination submission, p.4.

159 ENA, draft rule determination submission, p.4.

160 Ergon Energy, draft rule determination submission, p.1.

161 NSW DNSPs, draft rule determination submission, pp.4-5.

162 Energex, draft rule determination submission, p.2; ENA, draft rule determination submission, p.3; and NSW DNSPs, draft rule determination submission, p.3.

163 NSW DNSPs, draft rule determination submission, p.3.

should only impose reporting requirements that are proportionate to the scope of the demand management project and the resources employed to avoid possible additional administrative and compliance costs being incurred by the distribution business.[164]

The TEC and PIAC considered that distribution businesses should be subject to more robust reporting requirements on the outcomes of demand management projects subject to the incentive scheme or innovation allowance.[165] These stakeholders considered that distribution businesses should report on the details of spending on demand management projects, the performance outcomes, and the value of network investment saved. Further, they considered that distribution businesses should be required to report data in a clear and consistent manner to allow comparison across businesses.

Further, the TEC considered that distribution businesses should be required to report on any underspend in their innovation allowance.[166]

6.3 Overview of the final rule

The final rule gives the AER the power to implement a DMIA, having regard to a demand management innovation allowance mechanism objective and taking into account certain principles. The DMIA objective and principles as set out in the final rule are provided in Box 6.1.

Box 6.1 Demand management innovation allowance objective and principles

Objective[167]

The objective of the demand management innovation allowance mechanism is to provide distribution businesses 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).

Principles[168]

In developing and applying any demand management innovation allowance mechanism, the AER must take into account the following:

1. the mechanism should be applied in a manner that contributes to the achievement of the demand management innovation allowance objective;

164 Energex, draft rule determination submission, p.2; ENA, draft rule determination submission, p.3.

165 PIAC, draft rule determination submission , p.2; and TEC, draft rule determination submission, p.6.

166 TEC, draft rule determination submission, p.6.

167 NER Clause 6.6.3A(b).

168 NER Clause 6.6.3A(c)(1)-(4).

2. demand management projects, the subject of the allowance should:

   (i) have the potential to deliver ongoing reductions in demand or peak demand; and

   (ii) be innovative and not be otherwise efficient and prudent non-network options that a distribution business should have provided for in its regulatory proposal;

3. the level of the allowance:

   (i) should be reasonable, considering the long term benefit to retail customers;

   (ii) should only provide funding that is not available from any other source, including under a relevant distribution determination; and

   (iii) may vary by distribution business and over time;

4. the allowance may fund demand management projects which occur over a period longer than a regulatory control period.

6.4 Commission's analysis

The final rule includes a high level objective and supporting principles rather than detailed prescription in the NER. The objective provides the broad overarching purpose of the scheme, with the principles guiding the AER's discretion in developing the extent and scope of the innovation allowance consistent with the objectives.

6.4.1 DMIA objective

The objective is broadly consistent with that proposed by the COAG Energy Council and the TEC in their rule change requests. The approach taken in the final rule is also consistent with the approach taken to the objectives of other incentive schemes in Chapter 6 of the NER.

The objective in the COAG Energy Council rule change request also contained a description of the activities/projects that they considered should be included in the innovation allowance. These activities included: both technology and pricing based approaches, efficient connection of embedded generators, and the costs and impacts on network system operations of these approaches. The TEC's proposal was similar, but did not include specific reference to the connection of embedded generation. The Commission does not consider it appropriate for this detail to be included within the objective. The applicability of projects subject to the innovation allowance has been captured as a principle within the final rule (see discussion on the second principle below).

The COAG Energy Council's proposed objective and that provided in the final rule differ in respect of the explicit reference to the efficient connection of embedded generators. The Commission does not consider it necessary to include this detail in the final rule for two reasons. Firstly, the Commission recently amended Chapters 5 and 5A of the NER to assist in the efficient and transparent connection of embedded generation.[169] As a result of these amendments, the Commission does not consider it appropriate that distribution businesses receive additional funding to incentivise what they are required to do under the NER, that is, the efficient connection of embedded generation. Secondly, where an innovative way of connecting embedded generation is developed that has the potential to deliver ongoing reduction in demand reduction or peak demand, the applicability of this project would be subject to principle two (see discussion below).

6.4.2 DMIA principles

As noted above, the TEC considered that the innovation allowance should be administered by the AER in its current form. As such, the rule change requests replicated the approach currently taken by the AER and did not include explicit principles.

The final rule contains several principles.

The **first principle** clarifies that the innovation allowance should be applied in a manner that contributes to the demand management innovation allowance objective. As the obligation to develop an allowance mechanism already requires the development to be consistent with the objective, this principle clarifies that the application of the allowance mechanism by the AER must also contribute to the DMIA objective.

The **second principle** concerns the nature of projects that will be subject to the innovation allowance. The innovation allowance should provide funding to distribution businesses for undertaking projects that deliver a reduction in demand and/or peak demand.[170] The Commission considers this is likely to lead to lower long-term network costs and therefore lower prices for consumers. The principle also clarifies that these projects should be innovative and not otherwise be projects that a distribution business should have provided for in its regulatory proposal. This principle clarifies that the AER should ideally focus on those projects that are likely to result in a sustained and/or ongoing reduction in demand and are not business as usual operations for the businesses. This should incentivise distribution businesses to consider more innovative projects for which the outcomes may be less certain and therefore they may not otherwise trial. This principle also captures the objective proposed by the COAG Energy Council and the TEC, which focussed on the ability of

169 AEMC 2014, Connecting Embedded Generators, Rule Determination, 17 April 2014; and AEMC 2014, Connecting Embedded Generators Under Chapter 5A, Rule Determination, 13 November 2014 , Sydney.

170 The intent of this principle is to capture both reductions in average and peak demand. It is also intended to capture any shifts in demand.

different approaches (both technology and pricing based) to achieve useful and reliable demand reduction.

In its submission to the draft rule determination, the NSW DNSPs' considered that it is unclear how the word 'innovative' would be applied and interpreted. The Commission notes that the purpose of the innovation allowance is to provide funding for projects that distribution businesses may not have undertaken due to the risks involved in the project. The final rule provides the AER with the discretion to determine what an innovative project is when it applies the allowance. Broadly, the Commission expects this would include projects that have a degree of uniqueness and would not be undertaken under a "business as usual" approach.

The Commission also acknowledges the NSW DNSPs' concerns that the word 'ongoing' as used in this principle could exclude distribution businesses from pursing projects that are temporary or short term in nature. Read in the context of the objective, the Commission does not consider that the word ongoing could be used to exclude temporary or short term projects where it can be demonstrated that these projects deliver an ongoing reduction in demand. The Commission considers that the benefits of the project need to be ongoing, but not necessarily the project itself.

The **third principle** concerns the level of the innovation allowance. The final rule does not prescribe the level of the innovation allowance applicable to distribution businesses. The Commission does not consider it appropriate to include specific provisions that dictate the level of the allowance. Rather, the level should be determined by the AER, having regard to the innovation allowance objective and the third principle.

As such, the final rule provides guidance to the AER that the level of the innovation allowance should, among other things, be reasonable and take into account the expected long-term benefits to retail customers, and any other funding provided to a distribution business for demand management (that is, distribution businesses should not be receiving funding for demand management from multiple sources). The final rule also clarifies that the AER may vary the innovation allowance between distribution businesses and over time. The Commission considers that this will provide the AER with the flexibility to tailor the level of the allowance to an individual distribution business's requirements and circumstances.

A number of distribution businesses suggested that there may be instances where the businesses seek an amount of funding greater than that set by the AER. In response, the Commission considers that there may be merit in distribution businesses proactively assessing their funding requirements and approaching the AER to discuss them. However, the Commission does not consider that the NER is the appropriate location for any such provisions. Rather the ability of distribution businesses to negotiate for additional funding and any associated process is a matter for the AER to decide, but the NER would not prohibit this.

The COAG Energy Council and the TEC were both supportive of providing the AER with the flexibility to determine the amount of the innovation allowance for each distribution business.

The **fourth principle** concerns the length of time for funding of a particular demand management project. The funding of demand management projects should be able to continue across regulatory control periods. This principle clarifies that there may be instances where a distribution business wishes to fund a demand management project that has a long developmental and/or trial period that has the potential to extend beyond the end of a regulatory control period, or the project is commenced towards the end of a regulatory control period.

To account for these occurrences, the final rule clarifies that the AER may take into account the length of a project in determining the period over which the allowance may apply, which may span more than one regulatory control period.

The Commission considers that this clarification should provide distribution businesses with the ability to develop clearly scoped projects with the potential for funding over the life of the project. This should reduce the risk of funding shortfalls.

6.4.3 Reporting requirements

The final rule also includes a requirement that any mechanism developed and applied by the AER must require distribution businesses to publish reports on the nature and results of demand management projects the subject of the allowance.

The Commission considers this appropriate because a key aim of the innovation allowance is to share and disseminate any learning and experience with industry participants from projects and programs undertaken with the funding. As such, it is essential that appropriate reporting arrangements are in place that facilitates this sharing of knowledge.

The final rule does not stipulate by what method distribution businesses should disseminate this information. The Commission considers that the AER is best placed to determine the appropriate reporting arrangements as part of its role in developing and applying the innovation allowance. The Commission expects that the AER will consider the size of the project and the number of resources employed in the project in determining appropriate reporting requirements.

The Commission notes that the AER generally requests a consistent reporting format from each distribution business and expects that the AER would approach the reporting requirements under the innovation allowance in the same way. This should address TEC and PIAC's concerns that distribution businesses be required to provide consistent data to allow for comparison.[171]

171 PIAC, draft rule determination submission, p.2; and TEC, draft rule determination submission, p.6.

The Commission does not consider that distribution businesses should be required to report on any underspend of their innovation allowance, as suggested by the TEC. Requiring a distribution business to report on reasons for underspend may lead to perverse outcomes where a distribution business spends more than is efficient to avoid the need to report on any underspend.

Further, under the previous arrangements for DMIA, an adjustment is made to the distribution businesses revenue allowance in the second year of a regulatory control period to return any underspend or unapproved spend to consumers from the previous regulatory control period. The Commission expects that the AER will incorporate a similar feature into its new arrangements for the innovation allowance. Therefore, given that any underspend will be returned to consumers, reporting on any underspend does not appear necessary to promote the long term interests of consumers.

7 Implementation issues

The final rule requires the AER to develop and publish a demand management incentive scheme and demand management innovation allowance by 1 December 2016.

In submissions to the draft rule determination, EnerNOC, PIAC and the TEC called for earlier implementation of the incentive scheme and innovation allowance.[172] These stakeholders considered the incentives provided through the scheme key to distribution businesses pursuing more efficient investment decisions that will see consumers benefit from increased use of demand management.[173] The TEC considered that the AER should be required to design a DMIS by May 2016 and apply it by July 2016.[174]

In its submission to the draft rule determination, the AER considered that the application of the scheme and allowance midway through a regulatory control period would create considerable costs and uncertainty, with unknown benefits. It considered that the application of the incentive scheme midway through the regulatory period may require a reopening of the relevant distribution determination which would impose considerable costs on distribution businesses and the AER. It would require possible recalibration of the other measures and schemes applied to the business. Further it would involve a process for reopening existing determinations and applying the scheme which would normally occur through the Framework and Approach process.[175]

The Commission does not consider it is appropriate to provide for the application of the new DMIS or DMIA midway through a regulatory control period.

In respect of the demand management incentive scheme, the AER's current regulatory determinations have been made having regard to certain factors and with the aim of achieving certain outcomes. Applying a revised scheme midway through a regulatory control period would require the AER to consult on how the incentive scheme should be applied to each distribution business, as it would in the Framework and Approach process. The relevant distribution determination would then need to be reopened and the AER would have to consider how to readjust the incentives applied in that regulatory determination to work out how to appropriately balance the incentives between network and non-network options. This may lead to an adjustment of the distribution business' maximum allowable revenue.

There are clear costs associated with doing this for both distribution businesses and the AER. The benefits are less clear, particularly as the broader regulatory framework and

172 EnerNOC, draft rule determination submission, pp.1-2; PIAC, draft rule determination submission, p.1; and TEC, draft rule determination submission, p.3.

173 EnerNOC, draft rule determination submission, pp.1-2; and PIAC, draft rule determination submission, p.2.

174 TEC, draft rule determination submission, p.4.

175 AER, draft rule determination submission, p.4.

the incentives contained within it already allow and encourage distribution businesses to explore non-network options as alternatives to network options.

Application of a new demand management innovation allowance mid-period would not be as problematic as early application of an incentive scheme. However, a reopening and amendment of the existing determinations would still be required. Given that the AER has applied an innovation allowance under the previous DMEGCIS for all distribution businesses currently, application mid-period is unlikely to be necessary and the benefits are unlikely to outweigh the costs.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
DAPR	distribution annual planning report
DMEGCIS	demand management and embedded generation connection incentive scheme
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DSES	demand side engagement strategy
DSP	demand side participation
EBSS	efficiency benefit sharing scheme
ENA	Energy Networks Association
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	national electricity market
NEO	national electricity objective
NER	National Electricity Rules
opex	operating expenditure
RIT-D	regulatory investment test for distribution
RIT-T	regulatory investment test for transmission
SCER	Standing Council on Energy and Resources

SSIS	small scale incentive scheme
STPIS	service target performance incentive scheme
TEC	Total Environment Centre
WACC	weighted average cost of capital

A Summary of issues raised in submissions

A.1 First round of consultation

The table below provides a summary of the policy issues raised by stakeholders in their submissions and supplementary submissions to the consultation paper. The table is ordered by key issue and sets out the Commission's response to each issue.

Table A.1

Stakeholder	Issue	AEMC response
Gap in the current regulatory arrangements		
Energy Network Association (p.2)	ENA considered the current scheme has been a reasonable first step but suggests the relatively modest practical uptake of the scheme means review and re-examination of the rules and scheme design is warranted.	The Commission notes these views. The Commission’s final rule provides a framework to guide the AER in developing and applying a demand management incentive scheme and innovation allowance mechanism which will help to balance the incentives on distribution businesses to make efficient expenditure decisions. The framework balances the trade-off between improved clarity for stakeholders on the way in which the scheme and allowance mechanism are developed and applied, with the flexibility required by the AER to balance incentives to undertake demand management with other components of the regulatory framework and as circumstances change. The final rule provides a framework that, if applied, has the potential to lead to more efficient decisions by distribution businesses that may reduce costs to consumers over time.
Energex (p.3)	Energex agreed with the proponents that the current framework may not be providing sufficient incentives for the businesses to pursue demand management options as a result of uncertainty in respect of the current scheme. They considered a DMIS should provide long term clarity of investment in demand management activities (points to AER's recent decision for AusGrid as an example of how mixed messages from regulatory bodies regarding the importance and application of demand management can lead to uncertainty - for example, benefits of proposed demand management initiatives likely to be marginal once more cost-reflective tariffs are in place).	
NSW DNSPs (p.1)	From a distribution businesses perspective, the current scheme	

Stakeholder	Issue	AEMC response
	has provided weak incentives from demand management largely due to: inability of scheme to capture market benefits from demand management initiatives; scheme operating as a pass through of costs rather than a true scheme which allows rewards for delivering defined goals; short term focus of scheme which only allows consideration of benefits which accrue within the period; complexity of the current scheme design; AER's narrow application of the scheme.	
CitiPower and Powercor (p.5)	Considered the relative costs of demand management and network solutions had limited the ability of distribution businesses to implement demand management alternatives. Experience had been that network solutions are typically lower cost than alternative non-network solutions (example provided). They considered the RIT-D may also limit the competitiveness of non-network solutions due to difficulties valuing options created by a deferral of network investments, potentially undervaluing investments in innovative solutions.	
United Energy (p.1)	Based on its own experience, UE considered that a key contributor to the perceived regulatory gap discouraging businesses from adopting demand management related to the infancy in the use of demand management across the industry, as well as to the relatively few economically and technically viable opportunities to implement demand management at this time. Projects undertaken to date have only been marginally viable relative to network investment. It considered this would change but that the Commission should look at mechanisms to help bridge the gap between trial and commercial viability of demand management options, including proposed access to upstream benefits.	
Major Energy Users Association	The MEU considered that with the recent changes to the network regulation rules and the greater use of benchmarking by the AER in assessing efficient levels of allowances for opex and capex,	

Stakeholder	Issue	AEMC response
(p.4)	networks might be incentivised to use demand management more as a method to get to the efficient frontier of costs, but there is no certainty this will occur. Strengthening the incentives for implementing demand management should encourage greater use of this tool.	
Energy Efficiency Council (p.2)	There is still a strong case for a DMEGCIS to address a number of distortions in NSPs' incentive structures. In summary, clarification of the DMEGCIS must be a priority, as: first, while there have been improvements in the incentive structures facing NSPs, NSPs still face incentives that create a supply-side bias; second, there have been no changes in market conditions in recent years that suggest clarification of the DMEGCIS is not a major priority; and third, the AER has demonstrated that they need to be pushed to introduce an effective DMEGCIS.	
EnerNOC (p.2)	The gap in the framework is in the current design of the DMEGCIS, as it is applied by the AER. This is because it does not provide a distribution business with an opportunity to make profits on demand management projects and as such is not a true incentive scheme.	
PIAC (p.3)	PIAC did not consider that the DAPR, DSES and the new RIT-D arrangements alone would be sufficient to encourage and support demand management.	The Commission considers that while recent reforms have been changing the way distribution businesses engage with non-network providers, and consider and assess demand management options as efficient alternatives to network investment, it may take some time before these reforms result in efficient demand management being considered and pursued as business as usual by the distribution businesses. It is for this reason that the Commission considers there is still a need to provide the AER with a tool to allow it develop and apply an incentive scheme for demand management. The scheme can be applied by the AER and is intended to balance the incentives to
Ergon (p.3)	Ergon considered that while the existing rules and incentive schemes encourage demand management, there is still the potential for changes to the framework to allow greater flexibility and freedom for distribution businesses to actively pursue demand management.	
Energex (p.3)	Energex noted that businesses need financial incentives to pursue broad-based demand management options that take into account	

Stakeholder	Issue	AEMC response
	the value of demand reductions to the wider supply chain, and assist customers to respond to price signals to reduce peak demand. It considered that tariffs and demand management programs are complementary and achieve the best results when used in tandem.	undertake network versus non-network options such that distribution businesses will make efficient investment decisions. The interaction between the demand management incentive scheme and other measures and mechanisms designed to encourage efficient decision making by the distribution businesses is set out in Chapter 3 of the final rule determination.
NSW DNSPs (p.3)	NSW DNSPs considered reforms to pricing and metering are related in the sense that they are aimed at facilitating greater levels of DSP. However, these are targeted at addressing very different issues with the market and regulatory arrangements and should therefore be viewed as complementary measures. It noted that the proposed reforms should not be seen to negate or diminish the benefits to consumers from demand management carried out by distribution businesses.	
PIAC (p.3)	PIAC was concerned about the apparent assumption that network tariff reform will do the work of demand management. This is because the evidence that cost-reflective pricing creates changes in customers' behaviour is inconclusive.	
Total Environment Centre (p.7)	TEC considered that its proposed DMIS rule change is complementary to, and in no way conflicts with, recent reforms to Chapters 5 and 5A in relation to the arrangements for connecting embedded generators.	
Institute of Sustainable Futures (p.7)	The slowing in energy demand and the rule changes in relation to connecting embedded generators under Chapter 5A and Distribution Network Pricing Arrangements are both helpful, but in no way mitigate the urgency of the DMIS rule change.	
Ergon Energy (pp.3,4)	Ergon suggested appropriate compensation to distribution businesses should be considered to expand the volume of demand management. This is because the costs of procuring demand management can be unevenly distributed across the	

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	supply chain and can impact the revenues of distribution businesses and market proponents. It considered there needs to be protection over the distribution businesses' costs, revenue and risks in order for distribution businesses to invest more heavily in demand management.	
Origin Energy (p.1)	Origin noted that the rules allow the AER to develop an incentive scheme to encourage implementation of efficient demand management. It also noted that the current scheme had only resulted in modest uptake of non-network solutions which, in an environment of rapid network expansion, indicates that incentives are skewed in favour of capital investment.	
Opower (p.1-3)	Opower suggested that the combination of the three policy tools addressed in the consultation paper - an innovation allowance, an incentive scheme, and decoupling via a revenue cap for distribution businesses - addressed related but different demand management barriers. Opower provided a number of examples from the United States to illustrate this point.	
ECC NSW (p.3)	ECC NSW considered that distribution businesses, rather than consumers, may be better placed to fully realise the benefits of distributed storage opportunities. On this basis, it considered the regulatory and revenue framework should encourage investment in such options rather than ignore or actively obstruct the consumer side take up of energy management options.	
Clean Energy Council (p.2)	The CEC strongly disagreed that any of the recent reforms addressed the matter of innovation in demand management, but noted that two reforms would influence demand management, without addressing the same issues as the DMEGCIS. These being the distribution tariff reforms and the RIT-D framework. However, neither of these reforms promote innovation in demand management or embedded generator connection. Therefore, the	

Stakeholder	Issue	AEMC response
	CEC still considered that there is an obvious regulatory gap created by an ineffective DMEGCIS.	
PIAC (p.6)	PIAC contended that ideally the NER would be amended to redress the inherent capex-bias and prioritise demand management and energy efficiency as the first options networks should consider, but in the meantime, an incentive scheme as has been applied to other areas such as capex (CESS) and opex (EBSS) seems a partial solution to increase investment in projects that will support the long term interests of consumers.	The final rule is not intended to promote demand management solutions at the expense of more efficient network options. Rather, it would be expected to be applied where the AER considers the regulatory framework is not providing a level playing field between network and non-network options.
AER (p.6)	AER noted that various changes have been made to its regulatory approaches which might help achieve balanced consideration of network and non-network options by distributors. However, it identified further potential gaps worth exploring: first, expanding measures that require distributors to consider options equally and allow other service providers to offer alternatives, eg. the RIT-D could also cover network replacements; and second, the issues the rule proponents seek to address via a specific incentive scheme, including market benefits payments and a target and bonus scheme. In respect of the latter, it considered some aspects of the proposals needed further consideration.	These issues are discussed further in section 3.4 and 5.4 of the final rule determination.
NSW DNSPs (p.3)	The NSW DNSPs noted that, in light of slowed demand growth and more uncertainty about optimal capital investment strategy, there is stronger basis for distribution businesses to adopt demand management options as the demand reductions required to achieve capital deferrals are lower. This makes it easier and more cost-effective to adopt-network alternatives.	The Commission notes these views.
PIAC (p.3)	PIAC agreed with a position put by Ausgrid in its regulatory proposal that falling and uncertain demand provides a more supportive environment for demand management, given the short timeframes for investment and implementation compared with	

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	augmentation and replacement infrastructure.	
GDF Suez (p.3)	GDF considered the incentive structure currently applied to the networks is sufficient to incentivise them to pursue demand management projects over network building. It considered there is no gap in the framework which would require a DMIS and noted that there are two offsetting incentives - the WACC and EBSS - which aim to encourage networks to move towards efficient expenditure decisions.	As noted in section 3.3, the final rule will guide the AER in its development of an incentive scheme to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
CitiPower and Powercor (p.5)	CitiPower and Powercor considered the limitations of the existing framework are a product of the rules and the AER's current design of the scheme. It considered the AEMC should consider further the approach adopted by Ofgem as this may provide stronger incentives for innovation non-network alternatives.	The Commission has had regard to approaches taken to demand management incentives and innovation in international markets.
Proposed demand management incentive mechanism		
Separation of the scheme and allowance		
Energy Network Association (p.2)	The ENA considered that clearer policy objectives and guiding principles for a separate IA and incentive scheme are critical features absent from the current framework.	The final rule makes specific provision for an innovation allowance in the NER and separates this from the incentive scheme by including separate provisions for the scheme and allowance mechanism. This will allow for the clear articulation of the objective of each component of the demand management incentive mechanisms. The Commission considers that the separation of the provisions for the incentive scheme and the innovation allowance will provide greater clarity to the AER, and to stakeholders, regarding the purpose of, and arrangements supporting, each component of the broader mechanism.
Ergon Energy (p.4)	Ergon supported the proposal to separate the DMIA and DMIS with the two having clearly defined frameworks and objectives.	
ECC NSW (p.4)	ECC NSW considered that codification of the DMIA within the NER would add substance to current practice within the AER.	
NSW DNSPs (p.6)	The NSW DNSPs considered that separating the DMIA and DMIS would help delineate the scope and differing focuses of the schemes and also clarify funding arrangements.	

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Energy Networks Association (p.3)	The ENA considered it appropriate for the DMIS and DMIA which have different objectives, parameters and funding methodologies, to be separately represented in the rules.	
Principles based approach		
CitiPower and Powercor (p.7)	CitiPower and Powercor noted support for a rules framework that sets out high level objectives and detailed principles that the AER must have regard to in making a regulatory decision (such as designing a scheme).	The final rule utilises a principles based approach to the development and application of the scheme and allowance. This approach avoids being too prescriptive and reflects the differing methods available to incentivise demand management, as well as the different circumstances in which it may be necessary to do so. If the rules are too specific, then they may constrain the AER in its development and application of the scheme and allowance mechanism. This could potentially result in an inflexible or ineffective scheme or allowance being developed and potentially applied to the businesses. This matter is discussed further in section 4.6.2.
Origin Energy (pp.1-2)	Origin considered that many of the principles proposed in the rule change requests could be addressed under the existing rules. However, it noted that the scheme had been applied in a limited manner to date, and so agreed there may be benefit in codifying specific objectives. This would provide the AER with greater guidance in enhancing the operation effectiveness of the scheme, or developing a replacement scheme.	
Energex (p.3)	Energex supported inclusion of high level objective and principles in the rules, supported by more detail in the proposed guidelines to be developed by the AER. However, it considered some of the detail proposed for inclusion in the rules by the proponents may be best placed in the guidelines. It also considered the merit of the proposed objectives and principles should be considered as part of further consultation.	
Energy Networks Association (p.2)	ENA did not consider the current balance of prescription/flexibility appeared optimum. It considered it was appropriate for clear objectives and principles to guide the AER's discretion in the design and implementation of a scheme or regulatory approach. It noted that under a fit-for-purpose regulatory approach, the degree of prescription and flexibility was adapted to match the specific	

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	context. It considered the rule changes were broadly consistent with past approaches by the Commission.	
NSW DNSPs (p.4)	The NSW DNSPs expressed support for the ENA's views on this matter. They did not consider the current balance of prescription/flexibility appeared optimum and that greater prescription in the rules was warranted in order to address the ambiguities and gaps identified in PoC. They considered that prescribing objectives, principles and criteria was appropriate and consistent with other aspects of the rules, while also providing the AER with greater clarity and certainty in undertaking its role.	
Ergon Energy (p.4)	Ergon Energy considered the framework needed to enable flexibility for delivering demand management opportunities. On this basis, it considered the current level of flexibility and discretion afforded to the AER may not be optimum.	
Ergon Energy (p.4)	Ergon Energy considered that flexibility and innovation would be paramount in the foreseeable future in order to connect increasing levels of embedded generation, maintain system security and avoid significant network investment. It considered it was necessary (at a minimum) to maintain incentives to enable supply chain changes to support embedded generation and ensure the costs of connection are not unfairly allocated across the supply chain.	
Origin Energy (p.2)	Origin considered that any changes to the rules should retain sufficient flexibility for the AER to adapt and improve the scheme in response to changing and evolving market conditions and the availability of technology information and knowledge.	
Total Environment	The TEC considered a key problem was that the AER had not considered the existing DMEGCIS rule to be sufficiently prescriptive for it to implement a scheme. The TEC considered its	

Stakeholder	Issue	AEMC response
Centre (pp.4,7)	proposed changes would provide the AER with greater direction and prescription which, in its view, the AER desired. It noted that the proposed changes would still leave the AER considerable discretion as to the nature of the scheme it designs and implements.	
AER (p.2)	The AER stated that its preference was to have discretion to consider the need for a scheme and innovation allowance, their longevity, and the merit of specific elements such as market benefits payments via a guideline and Framework and Approach process. This would allow for the flexible consideration of these matters alongside market and framework developments.	
PIAC (p.4)	PIAC contended that as the AER has not prepared a DMIS under the current NER, and in fact, Ausgrid prepared its own incentive scheme in response to this void, it would seem that the AER requires greater direction or prescription. The rule change requests provide this prescription, and PIAC considered this level to be both appropriate and necessary.	
MEU (p.4)	The MEU considered that the rules for a demand management incentive scheme should be as high level as the rules are for the other incentive schemes. To make the scheme more or less prescriptive than the others could lead to a bias in the outcomes.	
Ergon Energy (p.3)	Ergon Energy considered the rules could be overly prescriptive about the way in which a distribution business must pursue a demand management opportunity. It cited the RIT-D as an example of how overly prescriptive rules could inhibit innovation opportunities for demand management, market engagement and customer involvement. High levels of prescription in times when the market is undergoing significant change may reduce ability for distribution businesses to adapt and transform.	

Stakeholder	Issue	AEMC response
Energy Efficiency Council (p.3)	While the Council would theoretically prefer that the AER have wide-ranging discretion in the development of DMEGCIS, in order to account for the gradual change in energy market rules and NSPs incentive structures, the AER's recent draft determinations clearly indicate that there are cultural and skill problems within the AER that necessitate the development of more explicit requirements around DMEGCIS.	
Institute of Sustainable Futures (p.7)	In its hesitancy to apply a meaningful DMIS, the AER has explicitly and implicitly flagged the need for greater prescription in the NER to enable the AER to develop and apply an effective DMIS.	
Development of guidelines		
Origin Energy (p.2)	Origin endorsed the proposal to require the AER to develop guidelines which set out the methodology for determining incentive payments and codify the schemes administration. These would be developed consistent with the rules consultation requirements.	The Commission does not consider it is necessary to include an explicit requirement in the NER for the AER to prepare guidelines to support the application of the scheme or allowance mechanism. However, the final rule requires the AER to develop and publish the scheme and allowance mechanism in accordance with the distribution consultation procedures. As part of this process, the AER is required to consult with stakeholders on the design of the scheme and, at a minimum, publish a decision that sets out the scheme, the reasons for the scheme, stakeholder comments and responses to those comments. This matter is discussed further in section 4.6.4.
Applicable demand management projects		
Energy Networks Association (p.5)	The ENA supported the inclusion of both tariff and non-tariff based demand management projects within the scope of the DMIS. It noted that there was significant public benefit in measures that incentivise innovative tariff design and trial initiatives to support	The Commission notes these views. In relation to the DMIS, principle seven requires (among other

Stakeholder	Issue	AEMC response
	demand management. In light of the new distribution pricing rules, it considered innovative tariff design options will serve a useful empirical base of knowledge for future network tariff approval processes.	things) the AER to consider the possible interaction between the scheme and the requirement to meet any regulatory obligation or requirement. This principle recognises that the DMIS is not intended to reward a distribution business for implementing an efficient demand management solution where it is already required to do so under the rules or by any other regulatory requirement or obligation. For example, the AER may consider the introduction of cost reflective network tariffs would not be eligible for payment of an incentive reward under a DMIS on the basis that the new distribution network pricing rules require all distribution businesses to develop network tariffs which better reflect their cost drivers. In relation to the DMIA, principle two clarifies that, among other things, projects funded by the allowance should be innovative and not otherwise be projects that a distribution business should have provided for in its regulatory proposal. This principle clarifies that the AER should focus on those projects that are likely to result in a sustained and/or ongoing reduction in demand and are not business as usual operations for the businesses. This matter is discussed further in sections 4.6.5, 5.4.2 and 6.4.2.
NSW DNSPs (p.9)	The NSW DNSPs considered it would be in the long-term interests of users for distribution businesses to have incentives under the regulatory arrangements to undertake trials of innovative tariff structures. The insights gained would ensure distribution businesses make informed decisions about the future direction of tariffs. It considered that precluding tariff based options from funding under the scheme would limit the potential benefits to consumers from network businesses being able to better utilise existing assets.	
CitiPower and Powercor (p.8)	CitiPower and Powercor noted that the purpose of DMIS as stated by COAG was to encourage least cost network investment and operation by allowing access to a proportion of the full benefits achieved by a demand management solution. It also noted that the purpose of the DMIA was to provide a source of funding for the experiment and trial of innovative approaches to demand management. To the extent that tariff based options meet those objectives, it was not clear why they should be excluded.	
Total Environment Centre (p.9)	TEC considered the move towards more cost reflective network tariffs may in time lead to lower peak demand on networks. However, it considered there were a lot of uncertainties involved, including the variable responsiveness of households and businesses to tariff signals. Providing additional incentives to introduce tariff based demand management might allow them to allocate additional resources to making sure such an approach to demand management works in practice. It considered there was little benefit in excluding tariff based programs from the scheme.	

Stakeholder	Issue	AEMC response
Energex (p.4)	Energex considered the proposed DMEGCIS should include tariff and non-tariff based options, noting that broad based tariff options could be used to lower customer demand and defer capex while non-tariff based demand management could be both broad based and targeted to specific network constraints.	
Ergon Energy (p.6)	Ergon considered that both tariff and non-tariff based demand management activities should be included in any future incentive schemes on the basis that, if considered in isolation, the different types of solutions could compete against the other creating inefficiencies.	
AER (pp.7-8)	The AER considered there was limited merit in additional incentives to motivate distributors to undertake something that the new efficient pricing reforms would require. In querying what purpose an innovation allowance might be put to, it considered there might be a case for distributors trialling innovative pricing options. However, it noted that it was unclear how costly these trials could be.	
PIAC (p.7)	PIAC supported making the option of tariff based demand management available via the rule change and did not see any benefit in excluding this option. This is because its inclusion will allow further innovation (including tariffs that are not based on long run marginal cost).	
Energy Networks Association (pp.2-3)	ENA considered that the DMIS and DMIA should encompass all forms of demand management including connection and exporting of distributed generation units. It noted that demand management can take many forms and that it is important that the provisions in the rules reflect this and remain technology neutral.	
NSW DNSPs (p.5)	The NSW DNSPs noted supported for the view put forward by the	

Stakeholder	Issue	AEMC response
	ENA that the DMIS and DMIA should encompass all forms of demand management including connection and exporting of distributed generating units. It noted that demand management can take many forms and that it is important that the provisions reflect this and remain technology neutral.	
Major Energy Users Association (pp.7-8)	The MEU considers that as long as the benefit that is shared is net after all the costs to achieve the benefit are deducted from the gross value of the benefit, there is no reason not to include tariff based demand management in the incentive scheme.	
PIAC (p.5)	PIAC did not understand the relevance of the connecting embedded generators rule change, as it was made to address connection issues rather than financial incentives.	The Commission does not consider it necessary to include specific reference to embedded generation connections in the final rule for two reasons. Firstly, the Commission recently amended Chapters 5 and 5A of the NER to assist in the efficient and transparent connection of embedded generation. As a result of these amendments, it is unlikely to be appropriate for distribution businesses to receive a reward for, or additional funding to incentivise, something they are required to do under the NER - that is, the efficient connection of embedded generation. That said, under the DMIS, expenditure on embedded generation to avoid funded augmentations arguably falls within the scope of 'non-network options related to demand management'. In addition, under the DMIA, innovative ways of connecting embedded generation that may have the potential to deliver ongoing reductions in demand reduction or peak demand could fall within the scope of the DMIA.
Major Energy Users Association (p.6)	There is still a need to provide an ability to recognise the benefits provided to the networks by embedded generation. The new incentive rules should specify that embedded generation is to receive some of the benefits achieved by their operation and the basis on which these are to be shared with the network and consumers.	
AER (p.12)	The AER noted that changes have been made to Chapter 5 to improve technical transparency on generator connections. It considered this might not diminish any need to research and innovate with respect to generator connections. However, it will need to be considered alongside the appropriate role of the distributor in demand management.	
The demand management incentive scheme		
Scheme rewards - non-network market benefits		

Stakeholder	Issue	AEMC response
Energy Networks Association (pp.4-5)	The ENA was of the view that the consideration of market benefits created by a demand management project is likely to promote greater investment in such projects to the long term benefit of consumers.	The Commission notes these views. The final rule gives the AER the power to implement a demand management incentive scheme of its own design, taking into account certain principles and the objective of the scheme. Importantly, the design of the financial rewards under the scheme (that is, the value of the incentive) could be approached in a range of ways. This is recognised in principle three which clarifies that the AER may take into account the delivery of net economic benefits delivered to all those who produce, consume and transport electricity in the market when developing the scheme. The Commission acknowledges the concerns of stakeholders that the previous rules were not clear on whether the AER is able to develop an incentive scheme under the existing rules which allows distribution businesses to retain a share of the non-network related market benefits delivered by a demand management project. As noted above, the Commission considers that this concern is addressed by the third principle. This matter is discussed further in section 5.4.3.
NSW DNSPs (p.8)	The NSW DNSPs considered that introducing a scheme which allows DNSPs to capture a proportion of market benefits from demand management projects would increase investment in BAU projects and would justify projects which are not cost effective to an individual DNSP, but cost effective to the NEM. They considered this would deliver broader market benefits in the long term interests of consumers. It would also drive greater utilisation of the DMIA towards projects which have tangible outcomes in the near future.	
Energex (p.4)	Energex supported the proposal that businesses be able to receive a payment based on a proportion of the market benefits produced by a demand management project. In addition, it considered the framework should require the AER to allow for benefits delivered outside of the regulatory period in which the project is delivered (given long term nature of the benefits).	
Ergon Energy (p.6)	Ergon Energy agreed that where a demand management project created long term value for other market participants, a share of this longer term value would enable more demand management investment.	
Origin Energy (p.2)	Origin agreed that one way to strengthen the scheme would be to make explicit that the DMEGCIS objective was to capture benefits beyond the distribution system.	
Origin Energy (p.2)	Origin agreed that distribution demand management should have direct financial incentives that are comparable to those associated	

Stakeholder	Issue	AEMC response
	with network investment and that supply chain benefits should be taken into account when allocating rewards. It agreed, in principle, with consistency across regulatory methods for determining supply chain benefits, noting the RIT-D and the proposed DSRM.	
Total Environment Centre (p.8)	TEC noted that, ideally, demand management expenditure would be included in revenue proposals approved by the AER (as was the case in QLD and as proposed by Ausgrid, Energex and Ergon for the forthcoming period). In this instance, incentive payments based on market benefits should apply above a threshold of the planned performance.	
AER (p.9)	The AER noted in-principle reasons for why market benefits payments for distributors might be explored, including the 'split incentives' issue. However, it noted potential concerns, in particular: potential quantification challenges and whether the split incentives issue is best characterised as a market failure needing additional incentives for distributors. This might be a market opportunity for other demand-side service providers operating across the supply chain.	
Opower (p.5)	Opower stated that the proposal to quantify and share non-network benefits should be put into practice. Opower noted that similar approaches to benefit-sharing have proven successful at stimulating cost-effective investments in demand management resources in the United States. Opwer believed that any positive impact would be amplified in the unbundled and competitive NEM, where the current incentives for distribution companies to deliver system-wide benefits are more fragmented than in more traditionally integrated utility markets.	
CitiPower and Powercor (p.4)	CitiPower and Powercor considered the scope of the DMIS has limited the ability of DNSPs to implement demand management alternatives. It therefore supported expanding the scope of the	

Stakeholder	Issue	AEMC response
	current scheme to allow DNSPs to capture market benefits.	
ECC NSW (pp.4-5)	ECC NSW believed that a proportional payment to networks based on market benefits will provide incentives to networks to undertake demand management projects. Particular emphasis will need to be placed on the process and methodology for the calculation of market benefits and the incentive given will need to exceed the costs of such projects to the networks.	
Opower (p.2)	Opower considered that decoupling of revenue from electricity sales volumes alone would not promote demand management. In addition, the unbundling and deregulation of other portions of the electricity supply chain means that DNSPs have limited ability to capture "spill over" benefits from demand management investment that accrue up- or downstream from the network's regulated jurisdiction.	
EnerNOC (p.3)	Formulating the reward based on a proportion of the market benefits produced by a demand management project, means that there is no possibility of the available incentive causing a distribution business to pursue a demand management project that is not in the interests of consumers.	
NSW DNSPs (p.14)	NSW DNSPs considered that codifying a maximum share of non-distribution benefits available for reward for pursuing demand management projects was not appropriate and would add unnecessary prescription. It considered a more appropriate approach would be for the AER to examine this when developing the DMIS.	The Commission does not consider it is necessary or appropriate to prescribe in the rules a sharing ratio for the DMIS. In line with DMIS principle four, in designing the scheme the AER is required to take into account that the level of the incentive should be reasonable, considering the long term benefit to retail customers. This approach is consistent with the other incentive schemes in Chapter 6 of the NER. This matter is discussed further in section 5.4.3.
PIAC (p.6)	PIAC considered a 30 per cent benefit capture share was appropriate.	
Total	TEC considered there needed to be a robust methodology for	

Stakeholder	Issue	AEMC response
Environment Centre (pp.8-9)	calculating downstream or consumer benefits and a cap on the percentage of these which should be available to DNSPs. Despite having proposed a 50 percent cap on the market benefits, the TEC noted that it was comfortable with the lower cap of 30 percent as proposed by the COAG Energy Council.	
Origin Energy (p.2)	Origin considered that the impacts of different sharing levels and the duration of financial benefits needed rigorous testing before committing to both a threshold and benefit duration. It considered it is essential that net benefits be demonstrated and validated before they are allocated by way of reward and note the demonstrate, validation and payment of rewards should be included in the AER's annual compliance report.	
ECC NSW (p.5)	The ECC NSW agreed with COAG that a cap of 30 per cent of non-network benefits was appropriate.	
EnerNOC (p.4)	A floor on the share of market benefits that a distribution business can retain, instead of a cap, would provide better certainty in relation to the returns available for implementing demand management projects. EnerNOC supports a floor of 30 per cent. Provision of the reward will require the collection of data about the demand management activity, its costs and the avoided costs. The data should be used to judge the effectiveness of the DMIS and to benchmark the distribution businesses’ demand management activities.	
Scheme rewards - foregone revenue/profit		
Energy Networks Association (p.5)	The ENA considered that providing for the recovery of foregone profit/revenue in the rules was warranted to provide certainty to businesses proposing to make significant investments. It noted that the form of regulation is a separate discussion for the AER in consultation with the businesses. The specific provisions for the	The final rule gives the AER the power to implement a demand management incentive scheme of its own design, taking into account certain principles and the objective of the scheme. Importantly, the design of the financial rewards under the scheme (that is, the value of the incentive) could be approached in a range

Stakeholder	Issue	AEMC response
	DMIS should be framed so as not to implicitly or explicitly assume one form of regulation of another.	of ways. This is recognised in principle three which clarifies that, among other things, the AER may take into account the delivery of net economic benefits delivered to all those who produce, consume and transport electricity in the market when developing the scheme. The rule is flexible enough to allow the AER to include in the scheme a reward based on foregone revenue (or profit) where it considered this was appropriate. In addition, principle seven requires that the AER considers the interaction between the scheme and particular control mechanisms and their effect on a distribution business' available incentives. This component of principle seven recognises that particular control mechanisms will influence the strength of the incentives on distribution businesses to use pursue demand management options, and so will likely also influence the scope and design of the incentive scheme by the AER. It also provides the AER with the flexibility to adapt the scheme to any future changes in the form of control applied to the distribution businesses. This matter is discussed further in section 5.4.3.
NSW DNSPs (p.8)	The NSW DNSPs agreed with the ENA that the form of regulation was a matter for separate decision by the AER in consultation with DNSPs. They considered it would be inappropriate for the rules to explicitly or implicitly assume one form of regulation over another. While it is true that under a revenue cap foregone revenue would not be necessary, it should be codified so the AER has flexibility to incorporate this into the scheme in the form of control changes in subsequent regulatory determinations.	
CitiPower and Powercor (p.8)	CitiPower and Powercor considered that the rules could be framed to facilitate multiple forms of regulation.	
Energex (p.4)	Energex was supportive of the proposal to require the inclusion of a payment for foregone revenue resulting from a demand management project approved under the DMIA. It also noted that the DMIS should not pre-empt that a particular form of control will always apply.	
Ergon Energy (p.6)	Ergon considered there needed to be certainty around any appropriate recovery of foregone revenue to ensure the ability to recovery approved revenues is not compromised.	
Total Environment Centre (p.9)	The TEC noted that revenue caps were not prescribed in the rules. It considered that inclusion of a payment for foregone revenue or profit is insurance against a possible future return to price cap forms of control.	
AER (p.7)	The AER noted that the application of revenue caps meant that foregone revenue measures are no longer required. It noted that it would prefer discretion to consider the appropriateness of these matters should there be any future changes to control	

Stakeholder	Issue	AEMC response
	mechanisms.	
PIAC (p.7)	PIAC was not certain that foregone revenue provision was necessary in the NER. This was because all businesses are under or about to be under a revenue cap.	
EnerNOC (p.4)	If any distribution business is regulated under some form of price cap, it will need to be compensated for foregone revenue. However, distribution businesses regulated under a revenue cap do not need this compensation.	
Other issues		
Energy Network Association (pp.1-2)	The ENA considered that a longer term of view of the future role of demand management should be developed, although it noted that this would be out of scope of the rule change request. It referenced the recent decisions in NSW/ACT where "significant demand management programs proposed…have been subject to major cuts by the AER". It considered this was demonstrative that "more positive regulatory incentives and guidance are needed".	As noted in section 3.6, the Commission considers there may be benefit in the AER explaining how it will assess the efficiency of demand management project expenditure as part of the regulatory determination process. This would provide some certainty to distribution businesses regarding the AER's approach to the approving an expenditure allowance for demand management projects. This could be done in the expenditure forecast assessment guidelines, which set out the AER's proposed approach to assessing forecasts of operating and capital expenditure.
AER (pp.3-4)	The AER considered it appropriate to consider how changing market and regulatory conditions might affect balanced consideration of network and non-network options by distributors. However, it considered these changes also raise broader questions about the role of distributor demand management, and this role should be considered alongside the purpose of reforms for efficient pricing, and the need to protect emerging competition.	The Commission considers that distribution businesses will always need to be the decision makers with regard to whether a network or non-network option provides the most efficient solution to address a constraint on their networks. This matter is discussed further in section 3.2 of the final rule determination.
CitiPower and Powercor	CitiPower and Powercor considered there was merit in the AER considering not imposing STPIS penalties on DNSPs resulting from non-network alternatives being trialled. It noted that penalties	Principle seven of the final rule requires AER to take account of the possible interaction between the DMIS and any other incentives available to the distribution businesses in relation to undertaking

Stakeholder	Issue	AEMC response
(pp.4,5-6)	incurred under STPIS for failure of a demand management solution to address a limitation effectively increased the costs of the demand management solution because non-network parties had typically not been willing to accept any liability for these penalties. It noted the rules allowed the AER to consider this solution by requiring it to have regard to other incentive schemes when developing and implementing the DMIS and STPIS.	efficient expenditure on, or implementation of, relevant non-network options. Therefore, the Commission would expect the AER to consider the interaction between the DMIS and STPIS when developing and applying the scheme. Changes to the STPIS scheme are out of scope of this rule change request.
Opower (p.4)	Opower noted that the impact of a shared benefits incentive scheme - the one part of this policy mix that is not currently in place in Australia - should enable the critical middle step between innovation and long-term adoption of a new 'normal'.	Noted. The final rule requires the AER to develop a demand management incentive scheme in line with the scheme objective and principles.
Institute of Sustainable Future (p.8)	If well designed and non-trivial incentives are offered, then regulated entities will respond to such incentives - this being the objective of incentive regulation. Provided demand management expenses are treated on the same basis as other network expenses and this normal planning and budgeting approach to demand management is applied, then the DMIS could be very good in encouraging better performance by network businesses.	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
Eastern Alliance for Greenhouse Action (p.2)	Under the current rules, there are no clear financial drivers for network businesses to pursue activities within the demand management space. Critically, the proposed rule change will ensure that energy sector investment can be leveraged into Victoria's communities and council programs by enabling demand management activities to be profitable and de-risking new innovations and longer term approaches to managing network demand.	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
Energy Network Association (p.1)	The ENA noted there may need to be wider consideration of how current market arrangements impact the ability for network businesses to implement demand management or distributed generation solutions where they are the most efficient and	The Commission acknowledges this comment but notes that this matter is beyond the scope of the rule change request.

Stakeholder	Issue	AEMC response
	effective solutions in their own right. For example, the current framework is unclear as to how it would treat network businesses implementing distributed generation supply solutions for remote customers. In a number of circumstances, demand management and distributed generation are more than just substitutes for network augmentation.	
EMR (p.3)	EMR considered that, before implementing any changes to the NER that involved the use of smart meters, it was essential to ensure that these meters were proven safe for humans and the environment. In relation to the amount of prescription to be included in the NER, EMR considered it entirely inappropriate to prescribe the installation of any electricity meterage networks that operate using radiofrequency electromagnetic fields.	Noted. However, consideration of matters related to specific demand management enabling technologies are beyond the scope of this rule change.
ECC NSW (p.3)	ECC NSW considered that demand management initiatives need to be seriously considered in relation to capex alternatives, as well as in relations to augmentation and replacement capital expenditure. It noted that this would necessitate demand management initiatives being included in revenue proposals earlier, and in more detail, than has been done to date.	The final rule sets out obligations and principles, but the detailed design of the scheme is for the AER to develop in accordance with the distribution consultation procedures. This may include consideration of a distribution business's capex.
Opower (p.3)	Opower noted that the challenge of accurately forecasting demand will become more complicated as electric vehicles come online and embedded generation becomes more widespread. As such, demand management will remain a vital tool.	The Commission's Power of Choice review made a recommendation to clarify the existing provisions regarding the ability of the market operator, AEMO, to collect information on demand side participation to make its market operational functions and demand forecasting more efficient. A final rule in relation to this recommendation was made in March 2015.
Origin Energy (p.2)	Origin considered there would be benefit in requiring the AER to undertake periodic reviews on the effectiveness of the scheme to mitigate the risk that it stays static in a dynamic environment.	The final rule requires the AER to develop and publish the scheme and allows it to amend or replace the scheme, in accordance with the distribution consultation procedures, as appropriate. In addition, the Commission has designed a final rule that is sufficiently flexible to support the AER in developing and applying a scheme that can

Stakeholder	Issue	AEMC response
		be easily adapted to future developments in the market and regulatory arrangements.
GDF Suez (p.4)	GDF Suez considered that the DMEGCIS undermined customer choice and provided questionable customer benefits. It considered the scheme did not represent a best case policy outcome and ignored the fact that market derived/led initiatives are engaging consumers to make more informed choices about their network and energy consumption. If DMEGCIS is pursued in some form, GDF considered it should at least be sponsored by customers or retailers to support overall economic efficiency and enable customer choice.	For the reasons set out in section 3.2, the Commission considers that distribution businesses will always need to be the decision makers with regard to whether a network or non-network option provides the most efficient solution to address a constraint on their networks. The question of who is best placed to provide possible non-network solutions is a separate question. The frameworks in the rules should encourage distribution businesses to identify and pursue the most efficient (or least cost) solution, irrespective of whether that solution is a network or non-network option or, in the case of the latter, whether it is provided by the distribution business in house, or by a third party through a competitive tender. In addition, the final rule requires the AER to develop and apply a scheme that is consistent with the DMIS objective. This objective clarifies that the scheme should aim to provide distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The Commission notes that this is consistent with the NEO and is intended to lead to outcomes that are consistent with the long term interests of consumers.
EECCA (p.1)	EECCA recommended that the AER encourage energy savings at times of peak demand, particularly in constrained network locations, by: first, requiring TNSPs and DNSPs to annually publish the details of emerging demand constrained areas, the quantum of demand reduction required to defer investment, and the approximate value of deferred investment; and second, by publishing annual tables of conservation load factors by technology, sector and activity as agreed to by the (NSW) TNSPs and DNSPs.	The Commission notes that the transmission and distribution businesses are already required under Chapter 5 of the NER to publish annual planning reports which focus on the identification of system limitations and potential investment opportunities. Schedule 5.8 of the NER sets out the requirements of the distribution annual planning report. In reporting on system limitations, DNSPs are required to include (among other things): estimates of the location and timing of the system limitation; analysis of any potential for load transfer capacity between supply

Stakeholder	Issue	AEMC response
		points that may decrease the impact of the system limitation or defer the requirement for investment; and brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required. Detailed consideration of matters related to distribution and transmission reporting requirements are beyond the scope of this rule change.
EECCA (p.1)	The rules of any incentive scheme must be written to prevent electricity networks from claiming energy efficiency incentives for activities that are funded through pricing determinations or demand management incentives (and vice versa).	Principle four of the DMIS recognises that the level of incentive developed and applied by the AER should not include costs that are otherwise recoverable from any another source, including under a relevant distribution determination. In addition, principle 7 of the DMIS recognises that the scheme should not reward a distribution business for implementing an efficient demand management solution where it is already required to do so under the rules or by any other regulatory requirement or obligation. This matter is discussed further in section 5.4.2.
The demand management innovation allowance		
Design and scope of the innovation allowance		
Energy Networks Association (p.3)	ENA considered that greater certainty around guiding objectives and design principles would improve certainty for the businesses seeking to make significant investment in demand management projects which have high upfront costs. This is likely to increase future utilisation of the innovation allowance.	The final rule contains several principles to guide the AER in developing and applying the demand management innovation allowance. Further information on the principles and objective of the demand management innovation allowance can be found in sections 6.4.1 and 6.4.2 of this final rule determination.
Energex (p.4)	Energex supported codifying the requirements for the innovation allowance in the rules to provide certainty that the IA will continue	

Stakeholder	Issue	AEMC response
	to be applied consistently.	
AER (p.11)	The AER agreed that the additional proposed specifications would merely be formalising current AER practice and are themselves unlikely to increase uptake of the innovation allowance.	
AER (p.11)	The AER noted that it preferred discretion to be able to flexibly consider this issue in the context of market and framework changes. Consideration of this point will depend on the appropriate role of distributor demand management.	
PIAC (p.5)	PIAC supported the inclusion of the DMIA in the NER as essentially an R&D fund for network businesses. PIAC considered that greater certainty may increase the likelihood of distribution businesses participating in the scheme.	
Opower (p.4)	Opower considered that the DMIA should be maintained, as pilot funding has proven essential to new policy and technology development.	
Institute of Sustainable Futures (p.7)	ISF considered DMIA could no doubt be improved, but that it was so small as to be tokenistic and was not focussed on maximising net benefits of demand management to consumers. It considered that the AEMC would be wise not to be unduly distracted by the DMIA in addressing the substantive issues around the DMIS.	
Major Energy Users Association (p.6)	The MEU considers that greater coordination of the projects funded by the DMIA is required in order to eliminate duplication. Most importantly, the MEU is concerned that DMIA projects are identified by the networks with little input from consumers or recognition of what other networks have done or are planning, and that there is no open sharing of the results of the projects undertaken.	

Stakeholder	Issue	AEMC response
NSW DNSPs (p.7)	The NSW DNSPs were concerned there may be a mismatch between the value placed on demand management by customers and the level allowed by the AER acting on behalf of customers. It considered the rules should require the AER to demonstrate how it had identified and taken into account customer preferences and their willingness to pay for demand management innovation, and to outline in a supporting guideline its methodology for calculating the DMIA. Transparency from these amendments would provide more certainty and confidence to DNSPs in how the IA was determined and may result in the size of the IA being set at a level which is meaningful and better aligned with customer preferences.	
Level of funding		
Energy Networks Association (p.3)	ENA considered the overall size of the innovation allowance was an issue for the AER and not an appropriate matter for rules specification.	The final rule does not prescribe the level of the allowance applicable to distribution businesses, as the Commission does not consider it appropriate to include specific provisions in the NER. Rather the final rule introduces a principle that allows the AER to set the level of the allowance having regard to the innovation allowance objective and principle four about the reasonableness of the innovation allowance. The AER is also required to develop the DMIA according to the distribution consultation procedures. This will provide stakeholders with an opportunity to comment on the proposed approach to calculating the allowance. Further discussion on the level of the innovation allowance can be found in section 6.4.2 of this final rule determination.
NSW DNSPs (p.6)	The NSW DNSPs considered the relative size of the innovation allowance and how it was calculated are factors which have contributed to its lower uptake. They considered there would be significant benefit if there was greater transparency and predictability around how it is calculated (for example, is it based on the AER's understanding of typical demand management costs which are then scaled to the relative size of each businesses average allowance in the previous period or is it determined consistent with the amount provided in the previous period?).	
NSW DNSPs (p.7)	The NSW DNSPs considered it was appropriate for the AER to determine the size of the innovation allowance and that this may vary between DNSPs. However, a more meaningful level could be achieved if the AER was required to consult on its methodology for determining the size of the allowance.	

Stakeholder	Issue	AEMC response
CitiPower and Powercor (p.7)	CitiPower and Powercor proposed that the ex-ante capped allowance continue to be provided as additional fixed revenue for each year of the regulatory control period. However, it considered an amendment to the scheme was required whereby DNSPs could seek further funding above the capped amount, subject to AER pre-approval of such initiatives.	
Energex (p.4)	Energex agreed with the ENA that the size and application of the innovation allowance should be determined by the AER.	
Ergon (p.5)	Ergon Energy agreed that the size of the innovation allowance and strict time limits limited the scope of innovation projects that could be undertaken. As customers pay for the scheme, it considered any changes in costs needed to take into account the customer perspective.	
Total Environment Centre (p.8)	TEC considered that the current small size of the DMIA would be fine if there was an effective DMIS operating alongside it. It noted that the DMIA could be improved by removing the de facto $1 million cap, but considered it was not necessary to reflect these changes in the rules.	
CitiPower and Powercor (pp.5,6)	CitiPower and Powercor considered a capped innovation allowance had limited the ability of DNSPs to implement demand management alternatives. It considered that a capped allowance constrained the ability of DNSPs to invest in innovation. Given the rapid rate of technological change, it considered a well-functioning scheme should facilitate a DNSP's ability to respond and realise greater benefits. It also considered the rules should enable further funding (beyond the cap) following pre-approval by the AER.	
Reporting on findings from project undertaken with innovation allowance		

Stakeholder	Issue	AEMC response
Energy Networks Association (p.3)	The ENA recognised there may be some overlap with DAPR and DSES. However, given the innovation allowance is funded by network consumers with the explicit goal of producing a 'public good' (information and data on innovative projects), it considered it was appropriate for tailored reporting arrangements to be in place.	The final rule includes an obligation on the AER to impose reporting requirements on distribution businesses as part of the innovation allowance. The Commission considers this appropriate because a key aim of the innovation allowance is to share and disseminate any learning and experience with industry participants from projects and programs undertaken with the funding. The final rule requires the AER to develop the scheme and allowance according to the distribution consultation procedures. As such, stakeholders will have an opportunity to comment on the form the reporting takes. Further discussion on the reporting requirements contained in the final rule can be found in section 6.4.3 of this final rule determination.
Energy Networks Association (p.4)	The ENA considered thought needed to be given to additional reporting obligations being proportionate to the scale of the project and resources employed. This would aim to ensure the rules did not result in unnecessary regulatory burden.	
NSW DNSPs (pp.7-8)	The NSW DNSPs supported the ENA's view that the current annual reporting requirements under the DMIA were sufficient. However, if further changes were deemed necessary, it considered these should be geared toward sharing industry DMIA knowledge (eg. through stakeholder workshop or working group) in order to provide maximum benefit and minimise duplication.	
CitiPower and Powercor (p.7)	CitiPower and Powercor considered the current reporting requirements were sufficient to share the learnings from DMIS projects within the industry, in light of the DAPR and the AER's existing DMIA reporting requirements. It noted that DNSPs were likely to undertake their own research and trials of non-network alternatives even where published information regarding similar projects was available. This reflects a prudent approach to infrastructure development having regard to different characteristics of the networks.	
Ergon (pp.5-6)	Ergon Energy noted that DMIA funded projects were substantially different from those included in the DAPR and therefore reporting requirements should remain separate. It agreed that reports on DMIA projects and outcomes should be made available.	

Stakeholder	Issue	AEMC response
Ergon (p.5)	Ergon Energy suggested that if reporting requirements were combined, consideration would need to be given to s127C of the Electricity Regulation 2006 (QLD) regarding preparation of a demand management plan as there would likely be duplication in reporting without modification.	
Origin (p.3)	Origin noted its strong support for a requirement for DNSPs to share data, results and learnings gained from the IA, especially in relation to pilots testing the effectiveness of network tariff structures. It considered that sharing data and results in this regard is critical to the success of complementary PoC reforms, particularly network pricing.	
Total Environment Centre (p.8)	TEC considered that clear, consistent, public and transparent reporting of expenditure and outcomes should be applied to the DMIS and network demand management in general (in addition to the DMIA) as a matter of good practice and accountability. It considered there was a need for a higher standard of accountability and transparency by networks and for better oversight of DMIA spending by the AER.	
AER (p.7)	The AER considered there was questionable merit in requiring distributors to publish further information on demand management activity. It noted that it had commenced consultation to improve the information that distributors provide via their annual planning reports — information that might be used by other demand-side service providers.	
PIAC (p.6)	PIAC supported clear, consistent, regular, public and transparent reporting of expenditure and outcomes. PIAC suggested it should be applied to both the DMIA and the DMIS as a matter of good practice and accountability. That is, there is an overdue need for a much higher standard of accountability and transparency from	

Stakeholder	Issue	AEMC response
	networks, and for better oversight of DMIA spending by the AER.	
Time limiting the application of the innovation allowance		
Ergon Energy (p.6)	Ergon Energy noted its support for a time-based measure, providing the time scales and rules surrounding funding are clearly defined so projects could be scoped without fear of funding shortfalls should the scheme change.	The final rule clarifies that the AER may take into account the length of a project in determining the period over which the allowance may apply, which may span more than one regulatory control period. This point is further discussed in section 6.4.2 of this final rule determination.
Ergon Energy (p.5)	Ergon Energy noted that it had utilised the IA significantly over the current period and that several projects had now become BAU activities. It suggested the following changes would increase participation: first, certainty of funding for projects over the regulatory control periods (ie for the entire project life); and second, avoiding overly prescriptive codes which may reduce the range or reach of potential projects.	
Energy Networks Association (p.4)	The ENA sought further discussion and clarity from the AEMC on the concept of time-limiting the IA (that is, is it time of operation of the scheme or recognition that the nature of the projects considered eligible of the IA could shift through time).	Both the time of operation of the scheme itself and the timing of projects are relevant issues that this final rule addresses. As discussed above, the final rule clarifies that projects may span more than one regulatory control period. In addition, the final rule does not prescribe a limit for the application of the innovation allowance. The Commission does not consider it appropriate to mandate an end to the innovation allowance in the NER. Rather, the final rule provides the AER with the discretion to apply the innovation allowance and so determine if, and when it is no longer required.
NSW DNSPs (p.8)	The NSW DNSPs considered it would be appropriate for the rules to specify a period of assessment and review of the scheme. At a minimum, it suggested the scheme should be allowed to operate for a period of 5-7 years before being reviewed as this would provide certainty around the intended application.	
CitiPower and Powercor (p.8)	CitiPower and Powercor were not clear why the IA should be time-limited given that new technologies are expected to continually arise.	
Energex (p.4)	Energex considered the IA should be a time limited measure. In determining timeframes, it considered the AER should be required	

Stakeholder	Issue	AEMC response
	to take into consideration the maturity of the market and provide sufficient notice of when the allowance will be phased out to ensure visibility for future planning.	
Total Environment Centre (p.8)	The TEC noted that it saw no time limit on innovation and R&D by networks. If the DMIA is resulting in innovation, it should be strengthened, not eliminated over time.	
AER (p.11)	The AER noted that there had been minimal uptake of the innovation allowance and that it was unclear if this had been a product of the regulatory framework historically not presenting a balanced value proposition to implement non-network projects beyond the trial stage. It noted a preference for discretion to consider the continued relevance of the innovation allowance. Any allowance for distributor innovation in non-network activity needs to be cognisant of whether these activities are to be the sole responsibility of the regulated distributor.	
PIAC (p.6)	PIAC did not support the DMIA being time limited because it is effectively an R&D fund. If it were to cease, this would imply that network businesses were able to fully fund innovation from profits or elsewhere which would be ideal, but unlikely, given experience to date.	
General issues		
Requirement for further public consultation on design		
Energy Networks Association (p.1)	ENA encouraged consideration of targeted workshops as part of rule change process to consider detailed design and implementation choice, and align stakeholders expectations around any changes to the arrangements.	The final rule sets out obligations and principles, but the detailed design of the scheme is for the AER to develop in accordance with the distribution consultation procedures. This will provide stakeholders with an opportunity to provide input into the design.

Stakeholder	Issue	AEMC response
Transgrid (p.3)	Transgrid encouraged the AEMC to consider undertaking stakeholder workshops to further engage on the issues raised in the rule change request, consultation paper and submissions.	
Demand management at the transmission level		
Grid Australia (pp.1-2)	Grid Australia proposed that the AEMC consider the potential for demand management by TNSPs to ensure alignment between the incentives and regulatory treatment of demand management activities by network businesses across the NEM. It recognised that the nature of demand management may differ between the transmission and distribution networks, believed it important that the rules support measures that encourage efficient demand management across both.	The Commission has considered the views put forward by these stakeholders in their submissions. It recognises that transmission businesses can, and do, contribute to effective demand management, albeit in a more limited capacity compared to the demand side and distribution businesses. In the context of this rule change process, the Commission believes that consideration of the application of a demand management incentive scheme and innovation allowance to transmission businesses is out of scope. Further discussion on this point can be found in section 3.5 of this final rule determination.
Grid Australia (p.2)	Grid Australia proposed that the AEMC consider the need for an IA to be made available to TNSPs to undertake demand management innovation activities similar to the purpose and agreed outcomes in distribution.	
Grid Australia (p.2)	Grid Australia sought greater clarity on how the AEMC sees TNSPs participating in the demand management market, noting previous AEMC reviews have focussed on DSP at the distribution network level.	
Energy Networks Association (p.1)	The ENA encouraged consideration of broadening the scope of the rule changes to consider the transmission framework for demand management.	
Transgrid (p.2)	Transgrid considered the rule change consultation should be expanded to include consideration of the current regulatory framework for demand management by TNSPs. A holistic approach was likely to achieve better alignment between	

Stakeholder	Issue	AEMC response
	incentives and regulatory treatment of demand management by network businesses across the electricity system.	
Transgrid (pp.1-2)	Transgrid considered the regulatory framework should provide greater certainty and incentives for transmission networks to undertake efficient demand management activities. By limiting the scope of the current rule change process to DNSPs, it considered the AEMC was not harnessing the opportunity to consider total system benefits of demand management opportunities across the NEM. It noted that under current arrangements, TNSPs undertake demand management through network support cost pass through arrangements approved ex-post by the AER based on a forecast allowance. It also considered as an ex-post approval process, there was a risk that a cost pass through was not approved. This created regulatory uncertainty for these projects and potential optimisation between capex and opex may not be realised.	
City of Sydney (pp.2-3)	The City of Sydney suggested that the scope of the DMIS ought to be extended to include interaction between transmission and distribution businesses. This was to ensure that interlinked components of the electricity supply system are not overlooked.	
EnerNOC (pp.2-3)	The Transmission Frameworks Review has been completed, and has not addressed the issue of incentives for demand management for transmission businesses. Therefore, consider that the rule change should be extended to cover transmission businesses.	
Other general comments		
Sustainable living Armidale (p.1)	Sustainable living Armidale supported the proposed rule change because it understood that it would provide DNSPs with meaningful incentives to help their customers reduce peak	The Commission considers that the purpose of the rule change is to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient

Stakeholder	Issue	AEMC response
	demand, rather than build new infrastructure.	investment decisions.
United Energy (p.1)	To complement the proposed changes, UE noted support for the introduction of further financial incentives that extend further than opex cost pass-through. It encourage the Commission to look at the costs associated with the establishment of demand management schemes and consider approaches that provide greater incentives in the early years to cover establishment and customer education costs.	The Commission has considered this proposal but does not consider it is necessary to amend these expenditure objectives and factors, as proposed by the TEC. The Commission considers that the current regulatory framework, in addition to the revisions to the operation of the demand management incentive scheme and the innovation allowance would be sufficient address these proposed changes. This is further discussed in section 3.6 of this final rule determination.
NSW DNSPs (p.1)	The NSW DNSPs considered the changes proposed would likely contribute to the NEO as they were aimed at improving the effectiveness of the scheme. They considered the changes were appropriately targeted at addressing the flaws identified in the current operation of the scheme and if adopted, would likely promote economically efficient level of demand management in the NEM.	The Commission considers that the purpose of the rule change is to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
NSW DNSPs (p.1)	The NSW DNSPs supported the nature of the changes proposed and shared the view of the proponents that the current scheme had not been effective encouraging efficient levels of demand management in the NEM. It also considered the nature of the proposed amendments were non-controversial. It generally supported the proposed amendments, but had some concerns regarding the substance of the proposed changes.	
GDF Suez (pp.3, 6)	GDF Suez considered that the DMIS did not support efficient outcomes (and as such may be inconsistent with the NEO) as it undermines a market based approach, customer choice and provides questionable consumer benefits. Believe the scheme should be abandoned or drastically modified to enable it to be retailer led. Customer choice should be front and centre of an	The Commission considers that the demand management incentive scheme does have a role at the network level in facilitating efficient demand management options. This should be viewed in conjunction with broader regulatory reforms to introduce cost reflective network pricing and competition in metering arrangements to facilitate demand management at the retail customer level.

Stakeholder	Issue	AEMC response
	effective arrangement.	The question of who is best placed to provide possible non-network solutions is a separate question from the decision to pursue a non-network versus a network solution. The frameworks in the rules should encourage distribution businesses to identify and pursue the most efficient (or least cost) solution, irrespective of whether that solution is a network or non-network option or, in the case of the latter, whether it is provided by the distribution business in house, or by a third party through a competitive tender.
EECCA (p.1)	The EECCA considered that energy efficiency schemes delivered significant net benefits which could be increased if targets, duration and fuel coverage were expanded. It considered benefits could also be increased if savings were further targeted to reduce market and network peaks and avoided network infrastructure.	This final rule aims to balance incentives for distribution businesses to undertake demand management projects as alternatives to implementing network options. The objective of the changes is to encourage efficient decision making by distribution businesses such that consumers' demand for electricity services is met at lowest total system costs.
EECCA (p.1)	EECCA supported modelling and reporting that includes the location, volume and delivery timeframes of peak demand reductions.	The final rule includes reporting requirements for the innovation allowance.
Energy and Water Ombudsman Victoria (p.2)	EWOV noted the consultation paper highlighted historical investment in electricity networks is largely attributable to electricity price rises in most NEM jurisdictions. Over this period, EWOV has seen a correlation between price rises and associated issues facing Victorian electricity consumers.	The Commission notes the comments raised by the Energy and Water Ombudsman, Victoria.
Energy and Water Ombudsman Victoria (p.2)	EWOV considered it important that careful consideration is given to the potential impact of the additional complexity of new products on customers' understanding of, and active participation in, the market. To mitigate this problem, EWOV believed it critical that the adequacy of current customer protections is reviewed to ensure customers are clearly informed about terms and conditions; aware of the impact and potential consequences; and entering into	The National Electricity Retail Rules already contain some relevant consumer protections, including for customers with life support equipment. Further consideration of consumer protection provisions is outside the scope of this rule change. Further, Energy Market Reform Working Group's ongoing work

Stakeholder	Issue	AEMC response
	agreements with explicit and informed consent.	program to ensure consumer protections are appropriate where customers have a smart meter installed.
Energy and Water Ombudsman Victoria (p.2)	EWOV considered that regulators need to consider the impact of demand side innovation on vulnerable customers, such as those who have life support registered at the property and/or critical appliances (for health and safety). EWOV also considered it necessary to give further consideration to customers who have limited capacity to participate in the market.	
Energy and Water Ombudsman Victoria (p.3)	EWOV believed that it was crucial that a clear, consistent and comprehensive customer communications strategy is delivered by industry and government to a broad range of customer groups.	In the Power of Choice review, the Commission recommended that a comprehensive communication/education strategy be developed to support implementation of the reforms recommended in the review, and to more broadly improve consumer understanding of energy use and relationship to costs. The strategy was to be managed by a SCER working group with participation of stakeholders from consumer organisations and the electricity sector.
Kloud Multimedia (p.1)	Individuals and companies who have invested in renewable energy should be rewarded for this investment, and energy companies who encourage this should also be rewarded. The DMIS will do just this; making our energy market fairer for consumers.	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
Kloud Multimedia (p.1)	With limitless renewable energy from the sun, it is important that power companies help more of Australia go solar. With feed-in tariffs so low there is very little incentive to turn to solar. All energy consumers will benefit from this new rule and I support it wholeheartedly.	
ECC NSW (p.1)	Innovative and cost effective demand management initiatives have considerable potential to reduce costs to all consumers. ECC NSW also believes that there are long term risks to consumers if the current regulatory approach is not adjusted to have the ability	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.

Stakeholder	Issue	AEMC response
	to respond to new energy markets and services.	
ECC NSW (pp.2-3)	An effective DMIS has the potential to encourage and assist networks to adapt to new markets and services, particularly those associated with decentralised energy and storage options, electric vehicles and increasingly sophisticated energy management systems.	
Nigel Davis (p.1)	The combination of low-cost PV panels and, in the next five years, cost efficient batteries will bring about a sea change to the electricity generation and distribution industries. Mr Davis depicted his forecast of the electricity industry in 2035. As a result Mr Davis considered that government policy needs to ensure that the generation and distribution utilities look ahead and set their capital investment and pricing policies in the best interests of the consumer.	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
Sustainable living Armidale (p.1)	Sustainable living Armidale noted that demand management is better for the environment and cheaper for consumers than the ever increasing practice of expanding electricity networks. Sustainable living Armidale also considered that positive incentives rather than punitive ones are usually more effective.	The Commission has made a rule.
PIAC (p.2)	PIAC stated that to combat the cultural barriers that exist to demand management, an effective DMIS and other mechanisms (beyond monitoring through AMPRs) are required. There remains a capital expenditure bias in the NEM and this will remain until such time as there is reform of the NEM or significant change in NSP's business models to counter this bias.	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
Australian Air Quality Group (p.1)	AAQG considered it important to protect electricity companies by providing the best possible incentives to encourage demand management, whenever this would be cheaper than building new	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.

Stakeholder	Issue	AEMC response
	network infrastructure.	
Australian Air Quality Group (p.1)	AAQG noted that prior to the network regulation rule changes, the WACC allowed network businesses to base their charges on an assumed interest rate that was higher than the interest rate they actually paid, which resulted in these businesses investing more in network infrastructure to increase profits. To rectify this problem, AAQG recommended that future network charges should be based on what the network companies actually pay in interest (being that of a prudent network company).	The rate of return framework is not within scope for this rule change request.
Choice (p.4)	Choice considered that the DMIS rule change would give network businesses a chance to work with consumers to respond in moving to a more decentralised energy market and develop new business models and practices to deliver a more affordable energy future.	The Commission has made a final rule which requires the AER to develop a demand management incentive scheme.
Choice (p.6)	Choice was concerned that if the proposed rule was not adopted, it would send a strong signal to the AER not to provide meaningful incentives for demand management. This would encourage network businesses to continue building infrastructure and maximising profit, rather than undertaking cost-effective demand management to help consumers reduce demand and save energy.	
City of Sydney (p.2)	The City of Sydney noted that it had repeatedly argued for stronger action on demand management to mitigate unnecessary growth in electricity network infrastructure and recommended that further policy changes were needed to take full advantage of the opportunities that decentralised energy provides.	The Commission supports demand management where it represents an efficient alternative to network investment. As such, this final rule is intended to balance incentives for distribution businesses to undertake demand management projects as an efficient alternative to implementing network options. The Commission also notes that the DMIS is part of a suite of regulatory reforms aimed at supporting efficient investment that leads to lower network costs for consumers.
City of Sydney (p.4)	The City of Sydney recommended the setting of targets for demand management. It suggested a broadening of the role of the AER (or a combination of AER and AEMO) to foster innovation, by identifying areas of high innovation potential and seeking	

Stakeholder	Issue	AEMC response
	proposals from network businesses, not simply sitting in judgement on proposals emanating from network businesses.	
City of Sydney (p.5)	The City of Sydney noted that the narrowly-defined test of whether demand management measures are efficient ignores broader consideration of social, environmental and economic factors. The test which focuses on lowest total system cost may not necessarily be the best in terms of the long-term interests of consumers.	
City of Sydney (p.8)	The City of Sydney acknowledged that whether in its current form or as a "reformed DMIS", this scheme was unlikely on its own to be sufficient to optimise the level of demand management in the electricity supply system. The City of Sydney considered that the DMIS should be retained, strengthened and supported with other measures, especially those related to facilitating more embedded generation.	
John Gare (p.1)	John Gare expressed strong support for the consolidated rule change request. By way of factual input, Mr Gare provided a break-down of his electricity bills over the past seven years showing the average annual increase in the fixed supply charge (10.94 per cent increase).	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
Greg Johnson (p.1)	Vitally important that the AEMC accept the demand management incentive scheme rule change as it will make our energy market fairer for consumers.	The Commission has made a rule.
Michael Marx (p.1)	I urge the AEMC to accept the Demand Management Incentive Scheme Rule Change because it will make our energy market fairer for consumers.	
Eastern Alliance for Greenhouse	Unlocking investment in demand management will be critical in ensuring a smooth transition to more sustainable, intelligent energy networks. To make this transition, energy providers will	

Stakeholder	Issue	AEMC response
Action (p.1)	need to build new capabilities that enable them to capture and scale up new opportunities and tap into unconventional markets.	
Clean Energy Council (p.2)	DNSPs will need to play a crucial role in capturing the benefits of new technologies. A regulatory framework which does not empower networks to consider, develop and adapt to new technologies will be unlikely to do so. Given the continued rate of PV deployment and anticipated timeframe for commercially viable energy storage it is crucial that DNSPs are able to start the learning process now. An effective incentive scheme is required to facilitate this.	
Queensland Consumers Association (p.3)	Distributors, retailers, equipment manufacturers, regulators and governments should work much harder and more cooperatively than in the past to ensure that cost effective direct load control, plays a much greater role in the future management of peak demand.	The final rule requires the AER to develop a demand management incentive scheme that balances incentives for distribution businesses to pursue or procure demand management options where it is efficient to do so.
Queensland Consumers Association (p.3)	The Federal government should give high priority to implementing the recommendations in the Consultation Regulation Impact Statement on Mandating Smart Appliance interfaces issued by the Equipment, Energy Efficiency Committee of Energy Efficiency in 2013. This would greatly facilitate the adoption of a national approach towards direct load control of household appliances, including air conditioners.	The Commission considers that this issue is out of scope for this rule change request.
Queensland Consumers Association (p.3)	The Association considers it is important to recognise the role of demand management as an alternative, or complement, to not only augmentation capital expenditure, but also replacement capital expenditure, which is likely to be an increasing proportion of capital expenditure in the foreseeable future.	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.
Solar Citizens	Solar Citizens provided the opportunity for individuals to provide a submission through its website. Each of these submissions was	The Commission reviewed each of the submissions provided through the Solar Citizens campaign and notes the concerns of

Stakeholder	Issue	AEMC response
	unique and covered a variety of issues, including among other things: • high fixed service costs within residential electricity bills; and • the low level of feed-in tariffs for exported electricity from solar.	Solar Citizens regarding high fixed costs and feed-in tariffs, but these issues are out of scope for this rule change request. The Commission considers that some of these issues are addressed in the distribution network pricing arrangements rule published in April 2014.
Choice campaign	Choice provided the opportunity for individuals to provide a submission through its website. Most of the submissions received followed a common template that contained the following considerations: • Australian electricity prices have doubled between 2007 and 2014; • the rules can be changed to help ensure billions are not wasted on unnecessary 'poles and wires' in the future; • a request to follow the Power of Choice recommendations and support a cleaner, more decentralised energy system; • this would provide incentives for distribution businesses to undertake projects that reduce demand and benefit consumers.	The Commission has made a rule to balance the incentives to undertake network versus non-network options such that distribution businesses will make efficient investment decisions.

A.2 Second round of consultation

Where relevant, stakeholder comments in submissions to the draft rule determination have been addressed throughout the final rule determination. The below table summaries issues raised by stakeholders that were not explicitly addressed in the final rule determination and the Commission's response to these comments.

<table>
<tr><th>Stakeholder</th><th>Issue</th><th>AEMC response</th></tr>
<tr><td colspan="3">The role of distribution businesses in demand management</td></tr>
<tr><td>AGL (p.2)</td><td>AGL considered that the draft rule determination did not recognise that other parties might be in a position to provide demand management services at the grid level at a more competitive cost than distribution businesses. Demand management should be delivered through a competitive market and incentives to deploy demand management activities should be avoided or implemented in such a way that it does not stifle innovation or the development of the lowest cost solution. Lack of a competitive process in the rules means that demand management options explored will be limited to those options that are available to or chosen by the distribution business and will be priced only on the basis of the distribution business providing the service.</td><td rowspan="2">As outlined in section 3.2, distribution businesses will always need to be the decision makers with regard to whether a network or non-network option provides the most efficient solution to address a constraint on their networks. The question of who is best placed to provide possible non-network solutions is a separate question.

The final rule is not intended to give distribution businesses a competitive advantage over third parties in the demand management service market. The incentives in the broader regulatory framework will encourage distribution businesses to pursue the most cost efficient solution, regardless of whether it is provided by the distribution business itself or a third party.

Under the rules, distribution businesses are required to comply with the AER's Distribution Ring Fencing Guidelines. If the AER determines that certain non-network activities should be ring fenced in order to maintain contestability in the demand management services, it has the discretion to do so.</td></tr>
<tr><td>EnergyAustralia (p.3)</td><td>Consideration should be given to whether a distribution business should be prevented from providing demand management solutions to itself, especially where it can influence the competitive process, and as a minimum it should be ring-fenced to ensure competitive neutrality is maintained.</td></tr>
<tr><td colspan="3">Level of the innovation allowance</td></tr>
<tr><td>EnergyAustralia (p.3)</td><td>Any allowance needs to be cognisant of whether the activities are the sole responsibility of the distribution business as consumers should not be funding demand management projects where they</td><td>The final rule introduces a principle that allows the AER to set the level of the allowance having regard to the innovation allowance objective and principle four about the reasonableness of the innovation</td></tr>
</table>

Stakeholder	Issue	AEMC response
	duplicate work being done in the competitive energy markets or where there are questions in relation to whether the distribution business should be providing the service. The AER is best placed to determine the appropriateness of any allowance proposed by a distribution business.	allowance. The AER is also required to develop the DMIA according to the distribution consultation procedures. This will provide stakeholders with an opportunity to comment on the proposed approach to calculating the allowance and the scope of projects that may be funded under the allowance. Further discussion on the level of the innovation allowance can be found in section 6.4.2 of this final rule determination.
Other issues		
GDF Suez (p.4)	Use of, and reliance on networks is likely to change into the future. Distribution businesses should not be able to undertake projects that undermine consumer response and potential benefits into the future.	The final rule provides the AER with the flexibility to determine how to integrate the scheme and allowance into the broader framework that incentivises efficient demand management by distribution businesses, in accordance with future developments in the market. This includes flexibility to determine whether incentives need to be applied to distribution businesses at all in order to balance consideration between network and non-network options. This flexibility will enable the AER to adapt the scheme and allowance over time in accordance with future developments in technology, use of networks and consumer trends. This issue is discussed in more detail in section 4.6.3.
Snowy Hydro (p.2)	The future use of networks is uncertain and new functions and services are likely. Therefore the benefits of a DMIS to consumers are uncertain.	

Stakeholder	Issue	AEMC response
United Energy (p.1)	One of the key barriers to more wide spread adoption of demand management is the infancy in the use of demand management across the industry and the relatively few economically and technically viable opportunities to implement demand management at the present time. The AER should consider incentive mechanisms that will help to both bridge the gap between trial and commercial viability for demand management options and provide enduring incentives for the ongoing investment in non-network solutions across regulatory control periods.	In developing the incentive scheme and innovation allowance, the AER has discretion to determine the types of demand management projects that may be subject to these mechanisms in accordance with their objectives and principles. Under the final rule, the AER also has the flexibility to determine the period of time that any incentive scheme or innovation allowance will apply, and explicitly recognises that this may be longer than one regulatory control period. The timeframe over which an incentive can apply is discussed in section 5.4.2. The timeframe applicable to the innovation allowance is discussed in section 6.4.2.

B Legal requirements under the NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this final rule determination.

B.1 Final rule determination

In accordance with section 102 of the NEL the Commission has made this final rule determination in relation to the rules proposed by the COAG Energy Council and the Total Environment Centre.

In accordance with sections 91A and 103 of the NEL, the Commission has determined to make a more preferable rule.[176]

The Commission's reasons for making this final rule determination are set out in section 2.3.

The National Electricity Amendment (Demand management incentive scheme) Rule 2015 (final rule) is published with this final rule determination. Its key features are described in Chapter 4, 5 and 6 of this final rule determination.

The DMIS and DMIA will be in place by 1 December 2016.

B.2 Commission's power to make the rule

The Commission is satisfied that the final rule falls within the subject matter about which the Commission may make rules. The final rule falls within s. 34 of the NEL, as it relates to the operation of the National Electricity Market (NEM) (s. 34(1)(a)(i)), and the activities of persons (including registered participants) participating in the NEM or involved in the operation of the national electricity system (s. 34(1)(a)(iii)).

The subject matter of the final rule also falls under those matters set out in Schedule 1 of the NEL under s. 34(2). In particular, items 25, 26A, 26D and 26G, which relate to:

- **Item 25** – the regulation of revenues earned or that may be earned by owners, controllers or operators of distribution systems from the provision by them of services that are the subject of a distribution determination.;

- **Item 26A** – principles to be applied, and procedures to be followed by the AER in exercising or performing an AER economic regulatory function or power relating to the making of a distribution determination.

176 Under section 91A of the NEL the AEMC may make a rule that is different (including materially different) from a market initiated proposed rule (a more preferable rule) if the AEMC is satisfied that, having regard to the issue or issues that were raised by the market initiated proposed rule (to which the more preferable rule relates), the more preferable rule will or is likely to better contribute to the achievement of the National Electricity Objective.

- **Item 26D** – the economic framework, mechanisms or methodologies to be applied or determined by the AER for the purposes of items 25 and 26 including (without limitation) the economic framework, mechanisms or methodologies to be applied or determined by the AER for the derivation of the revenue (whether maximum allowable revenue or otherwise) or prices to be applied by the AER in making a distribution determination.

- **Item 26G** – incentives for regulated distribution system operators to make efficient operating and investment decisions including, where applicable, service performance incentive schemes.

B.3 Commission's considerations

In assessing the consolidated rule change request the Commission considered:

- the Commission's powers under the NEL to make the rule;
- the rule change requests;
- the fact that there is no relevant Ministerial Council on Energy (MCE) Statement of Policy Principles;[177]
- the AEMC's Power of Choice review final report to the COAG Energy Council;
- submissions received during first and second round consultation;
- the Commission's analysis as to the ways in which the proposed rules will or are likely to, contribute to the NEO;
- interactions with other relevant rule changes and review recommendations; and
- the revenue and pricing principles under s. 7A of the NEL.

B.4 Revenue and pricing principles

In applying the rule making test, the Commission has taken into account the revenue and pricing principles as required under s. 88B of the NEL as the consolidated rule change request relates to matters specified in items 25, 26A, 26D and 26G of Schedule 1 to the NEL relating to distribution system revenue and pricing. In light of the above considerations, the Commission has concluded that the final rule is consistent with the revenue and pricing principles for the reasons set out below.

177 Under section 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for Energy. On 1 July 2011 the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated Council is now called the COAG Energy Council.

Section 7A(2) of the NEL, states that network service providers should be provided with a reasonable opportunity to recover at least the efficient costs they incur in providing direct control network services. Under the final rule the opportunity for distribution network service providers to recover at least the efficient costs they incur in providing direct control services will not be affected.

The revenue and pricing principle in s. 7A(3) of the NEL requires network service providers to be provided with effective incentives in order to promote economic efficiency with respect to the direct control network services they provide.[178] The economic efficiency that should be promoted includes:

- efficient investment in a distribution system with which the operator provides direct control network services;
- the efficient provision of electricity network services; and
- the efficient use of the distribution system with which the operator provides direct control network services.

Under the final rule distribution businesses have the potential to be provided with effective incentives under the demand management incentive scheme to undertake efficient investment in relevant non-network options, relating to demand management, that facilitate the efficient provision of electricity network services to retail customers.

B.5 Civil penalty provisions

The final rule does not amend any clauses that are currently classified as civil penalty provisions under the NEL or the National Electricity (South Australia) Regulations. The Commission will not recommend to the COAG Energy Council that any of the amendments made by the final rule be classified as civil penalty provisions.

B.6 Declared network functions

Under s. 91(8) of the NEL, the Commission may only make a rule that has effect with respect to an adoptive jurisdiction if it is satisfied that the rule is compatible with the proper performance of the Australian Energy Market Operator's (AEMO) declared functions.[179]

The Commission considers that the final rule is compatible with AEMO's declared network functions because it is unrelated to them and therefore it does not affect the performance of these functions.

178 NEL s. 7A(3).

179 These are specified in s. 50C of the NEL.

C Principles and factors in the proposed rule specifications

The table below sets out the principles and factors which the COAG Energy Council and the TEC proposed for inclusion in the NER. The Commission has considered each of the proposed principles and factors, a number of which have been reflected in the final rule. The Commission's assessment of each of the proposed principles and factors, including the reasons for including the principle or factor in the final rule or otherwise, is also set out in the table.

Table C.1 Demand management incentive scheme

Proponent	Proposed principle or factor	AEMC response
Principles		
COAG Energy Council[180]	The scheme must have the following principles:	
	• recognise the need to incentivise networks towards implementing efficient DSP over the long term and not just the forthcoming regulatory control period	This concept is reflected in principle six of the final rule which relates to the length of the incentive.
	• align, to the extent possible, payment of any reward available under the scheme with the timing of benefits in order to smooth the bill impact on consumers	Any costs resulting from the application of the incentive scheme will be added to distribution businesses revenues which will be recovered from consumers through network prices. When developing their network tariffs, distribution businesses must comply with a number of principles, including the impact on consumers of changes in network prices. While the Commission agrees that it is important to smooth the bill impact on customers resulting from application of the scheme, the application of the distribution pricing principles in Chapter 6 of the NER will address this factor.
	• be simple to apply, such that the incentive design should be easy to understand, implement and administer	The final rule provides the AER with the discretion to develop the scheme of its own design, taking into account the principles and objective.
	• contribute to achieving a material change that is to be reported in the amount of efficient DSP in the market	The purpose of the scheme is to balance incentives on distribution businesses to undertake efficient expenditure on demand management. That is, the AER would be expected to apply the scheme where it considers the current incentive framework is not providing a level playing field between

180 COAG Energy Council rule change request, pp.12-13.

Proponent	Proposed principle or factor	AEMC response
		network and relevant non-network options. It is not intended to skew the incentives on distribution businesses to pursue relevant demand management options at the expense of more efficient network options.
	• non-distribution network benefits under this scheme should only be available where the distribution business has been unable to negotiate a share of these benefits from the beneficiary	This concept is reflected in principle four of the final rule. That is, the level of the incentive should not include costs that are otherwise recoverable from any another source.
	• the share of non-distribution network benefits available for reward for pursuit of demand management projects should be no more than 30 per cent of non-distribution network market benefits created by the project (the actual percentage may vary by business and by time where the AER considers different levels of incentive are required for the distribution business to pursue efficient demand side participation)	The Commissions considers it is appropriate for the AER to determine the sharing ratio, taking into account that the level of the incentive should be reasonable, considering the long term benefit to retail customers. This is reflected in principle four of the final rule.
	• as a further safeguard from potentially excessive rewards to distribution businesses, the non-distribution network related market benefits should only be available to the distribution business when they are substantiated and realised	This concept is reflected in principle two of the final rule. That is, the scheme should reward distribution businesses for implementing relevant non-network options that deliver net cost savings to retail customers. Delivery of net costs savings to customers requires that they be substantiated and realised.
TEC[181]	The demand management incentive scheme must be applied in a manner consistent with the following principles:	
	• demand management projects should address (current and/ or anticipated) network issues in order to qualify for inclusion in the DMIS, noting that potential network issues include network supply capacity, reliability, asset replacement and changing demand or local generation patterns;	This concept is reflected in the DMIS objective through the use of the term "non-network option". A non-network option is defined as a means by which an identified need can be fully or partly addressed other than by a network option. An identified need is the objective that a network business seeks to achieve by investing in the network. The use of 'non-network option' therefore reflects that only projects which are intended to address an identified issue on the network are applicable for inclusion in the scheme.

181 TEC rule change request, p.13.

Proponent	Proposed principle or factor	AEMC response
	• expenditure on demand management projects approved under this scheme must be treated equitably with other network expenditure approved under the determination process;	This concept is reflected in principle three of the final rule which recognises that the scheme should balance the incentives between expenditure on network and non-network options in relation to demand management
	• notwithstanding the above, consideration of funding for qualifying demand management projects shall recognise the need to incentivise network demand management over the long term, and not just for the forthcoming regulatory period;	As noted above, this concept is reflected in principle six of the final rule which relates to the length of the incentive.
	• payments to customers or other providers of demand management services under the scheme should reflect consideration of timing to smooth the bill impact on consumers;	As noted above, the application of the distribution pricing principles in Chapter 6 of the NER will address this factor.
	• the scheme design should be as simple as practicable to apply, such that it is easy to understand, implement and administer for all market participants; and	The final rule provides the AER with the discretion to develop the scheme of its own design, taking into account the principles and objective.
	• the scheme should contribute to achieving a material change that maximises in the amount of efficient demand management in the market	As noted above, the purpose of the scheme is to balance incentives on distribution businesses to undertake efficient expenditure on demand management. It is not intended to skew the incentives on distribution businesses to pursue relevant demand management options at the expense of more efficient network options.
Factors		
COAG Energy Council[182]	In developing the DSP incentive scheme, the AER must have regard to the following factors:	
	• market rates for comparable DSP services.	The Commission does not consider it is necessary for the scheme principles to reflect this level of detail.
	• the need to include in the cost-benefit assessment the value to customers participating in the DSP project of the services derived from electricity they would have used except for that participation.	The final rule provides the AER with discretion to design the scheme taking into account the principles. This includes the determination of the value of the incentives.

182 COAG Energy Council rule change request, pp.13-14.

Proponent	Proposed principle or factor	AEMC response
	• the range of market benefits permitted under the regulatory investment test for distribution.	The final rule provides the AER with the flexibility to determine the value of the incentive. Principle three of the final rule clarifies that in determining the value, it may (among other things) take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the market. The Commission would expect the AER to have regard to the process for identifying and valuing market benefits under the RIT-D where it decided to link the value of the incentive to the market benefits delivered across the supply chain by a demand management project.
	• the ability of DSP services to recover market benefits through fees, charges or other revenue.	This concept is reflected in principle four of the final rule. That is, the level of the incentive should not include costs that are otherwise recoverable from any another source, including under the relevant distribution determination
	• the effect of the particular control mechanism applied to the Distribution Network Service Provider on incentives to adopt or implement efficient non-network alternatives.	This concept is captured in principle seven of the final rule which requires that the AER take into account the possible interaction between the scheme and any particular control mechanisms and their effects on distribution businesses in relation to undertaking efficient expenditure on, or implementation of, non-network options.
	• the extent to which the relevant Distribution Network Service Provider is able to offer efficient pricing structures, having regard to the metering technology available on its system.	This concept is captured in principle seven of the final rule which requires that the AER take into account the possible interaction between the scheme and the requirement to meet any regulatory obligation or requirement. This would include the requirement for distribution businesses to provide cost reflective network tariffs.
	• any possible interaction with other incentive schemes.	This concept is captured in principle seven of the final rule which requires that the AER take into account the possible interaction between the scheme any other incentives available to the distribution businesses in relation to undertaking efficient expenditure on, or implementation of, non-network options.

Proponent	Proposed principle or factor	AEMC response
	• the net benefit to customers of facing changes in pricing resulting from the implementation of the scheme.	This concept is captured in principle four of the final rule which requires that the level of the incentive should be reasonable, considering the long term benefit to retail customers.
	• any possible interaction with other consumer demand response mechanisms being offered to customers.	This concept is captured in principle seven of the final rule.
TEC[183]	In developing the DMIS, the AER must have regard to:	
	• where available, past experience (in Australia and internationally) including costs, benefits and outcomes for comparative demand management services	The Commission does not consider it is necessary for the scheme principles to reflect this level of detail.
	• the need to consider in the cost-benefit assessment the value to customers participating in the demand management project of any significant additional cost or benefit of their participation (including the electricity they would have used or wasted except for that participation)	The final rule provides the AER with discretion to design the scheme taking into account the principles. This includes the determination of the value of the incentives.
	• the range of market benefits permitted under the regulatory investment test for distribution	As noted above, the Commission would expect the AER to have regard to the process for identifying and valuing market benefits under the RIT-D where it decided to link the value of the incentive to the market benefits delivered across the supply chain by a demand management project.
	• the effect of a particular control mechanism to which the DNSP is subject on incentives to adopt or implement efficient non-network alternatives	As noted above, this concept is captured in principle seven of the final rule which requires that the AER take into account the possible interaction between the scheme and any particular control mechanisms and their effects on distribution businesses in relation to undertaking efficient expenditure on, or implementation of, non-network options.
	• the extent a distributor is able to offer efficient pricing structures	As noted above, the concept is captured in principle seven of the final rule which relates to the interaction between the scheme and the requirement to meet any regulatory

183 TEC rule change request, p.13.

Proponent	Proposed principle or factor	AEMC response
		obligation or requirement.
	• any possible interaction with other incentive schemes	As noted above, this concept is captured in principle seven of the final rule which relates to the interaction between the scheme with other incentive schemes.
	• the willingness of customers to pay for any increases in costs or prices resulting from the implementation of the scheme	This concept is captured in principle four of the final rule which requires that the level of the incentive should be reasonable, considering the long term benefit to retail customers.
	• the distribution of any benefits of reduced costs or bills resulting from the implementation of the scheme	As noted above, the concept is captured in principle six which relates to the length of the incentive.