RULE

Australian Energy Market Commission

RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (DEMAND MANAGEMENT INCENTIVE SCHEME AND INNOVATION ALLOWANCE FOR TNSPS) RULE 2019

PROPONENT

Energy Networks Australia

5 DECEMBER 2019

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.

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SUMMARY

1 Energy Networks Australia (ENA) submitted a rule change request proposing amendments to the National Electricity Rules (NER or rules) that would require the Australian Energy Regulator (AER) to develop a demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) to apply to transmission network service providers.

2 The DMIS provides for incentive payments to undertake efficient expenditure on non-network options. The DMIA provides funding for research and development (R&D) on demand management projects that have the potential to reduce long term network costs.

3 The Commission's final rule determination is to make a more preferable final rule to apply the DMIA, and not the DMIS, to transmission network service providers.

4 Stakeholder submissions received by the Commission strongly support efficient demand management solutions that reduce the need for investment in transmission and distribution infrastructure. However, most submissions questioned the benefits to consumers of introducing the DMIS in particular, and were not convinced that this scheme is the best mechanism to incentivise efficient non-network solutions.

5 In the Commission's view, introducing a DMIA for transmission is expected to encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long term network costs and, consequently, could lower prices for consumers. Such innovation may play an important role in the transformation of the energy sector. The AER is expected to socialise network approaches and learnings by publishing DMIA reports for each transmission business on its website, as it currently does for distribution networks.

6 R&D can deliver overall benefits to consumers in the long term, but lead to higher costs in the short term. The nature of the regulatory control period imposed on networks, which 'resets' prices every five years or so, impacts the expected payoff of R&D projects. The DMIA addresses this issue under the regulatory framework.

7 The final rule provides the AER with discretion as to whether and how to apply the DMIA, including the level of the innovation allowance – consistent with ENA's proposal. Enabling the AER to apply the DMIA will improve the flexibility and responsiveness of the regime to changing technologies and market developments.

8 The decision to extend the DMIA to transmission regulation, but not the DMIS, is supported by the AER, AGL, Energy Consumers Australia, Public Interest Advocacy Group (PIAC) and South Australian Government in their submissions to the draft determination. The only other submission to the draft determination was by ENA, which maintains that the DMIS would result in increased innovation and use of non-network solutions – leading to lower prices for consumers.

9 The Commission is not satisfied the DMIS promotes the long term interests of consumers. It is not clear from the evidence presented by ENA that the incremental benefits of introducing

a DMIS are likely to outweigh the upfront costs to consumers. For example, if the DMIS is implemented, transmission businesses will receive incentive payments for undertaking non-network options that they already would have been required by the regulatory investment test for transmission (RIT-T) to adopt.

10 The Commission accepts ENA's view that networks may face upfront, transitional costs to develop their ability to utilise non-network options. But, ongoing incentive payments to transmission businesses are not necessary to overcome implementation barriers. These mostly one-off costs can be funded through AER revenue allowances. Other sources of funding may be available too – such as from ARENA or, as a result of this decision, the DMIA.

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1 ENA'S RULE CHANGE REQUEST

1.1 The rule change request

Energy Networks Australia (ENA) submitted a rule change request proposing amendments to the National Electricity Rules (NER or rules) that would require the Australian Energy Regulator (AER) to develop a demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) to apply to transmission network service providers.[1]

The DMIS would provide for incentive payments to undertake efficient expenditure on non-network options. The DMIA would provide funding for research and development (R&D) on demand management projects that have the potential to reduce long term network costs.

1.2 Current arrangements

Under the current rules, the DMIS and DMIA are only available for distribution network service providers. ENA proposes to apply the same approach to transmission, including giving the AER discretion as to whether to apply the schemes, and in determining the level of both incentives and the allowance.[2]

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

- provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management (through the DMIS)[3]
- provide distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs (through the DMIA).[4]

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

1.3 Rationale for the rule change request

ENA submits that the proposed rule change would promote innovation and create positive incentives for transmission businesses to undertake demand management approaches, which would benefit customers through lower transmission network and total system costs.[5]

Electricity network demand management generally helps to remove or reduce network constraints and investment, which potentially provides a less costly alternative to capital investment. Transmission businesses may be able to shift or reduce net demand on their network by, for example, providing financial incentives to encourage behavioural change or

1 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February2019.

2 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February2019, p. 3.

3 See NER clause 6.6.3.

4 See NER clause 6.6.3A.

5 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February2019, p. 3.

contracting for local generation support. Lower total system costs would mean lower electricity prices for consumers, all other things being equal.

ENA submits that the key driver for the proposed introduction of a DMIS for transmission is the current lack of positive financial incentives for the adoption of potentially lower cost non-network operating expenditure solutions. ENA considers there are 'practical implementation barriers' associated with putting in place a non-network solution – such as reputational and compliance risks, particularly when the market for non-network solutions is still developing. ENA considers that this potentially creates unbalanced incentives and a bias towards network capital investment under the current rules.[6]

ENA submits that the current regulatory framework does not provide certainty that any expenditure on research and development (R&D) to further develop efficient long-term non-network solutions will be able to be recovered by the transmission business. ENA states the framework provides a disincentive to incur expenditure on R&D because any expenditure results in an immediate increase in operating expenditure (opex), which is not necessarily offset by a decrease in either opex or capital expenditure (capex) in the same regulatory period.[7]

ENA said an increase in the take-up of non-network alternatives by transmission businesses, and in research to establishing the viability and commercialisation of innovative new non-network solutions, will assist the development of the non-network industry more broadly and increase confidence in non-network solutions. This in turn, ENA says, can be expected to result in a 'broadening and deepening' of the market for non-network services, which currently remains in its relative infancy: 'This will bring benefits to other potential users of non-network services, including AEMO in its capacity as market operator in managing system stability and ensuring reliability.'[8] Further, ENA submitted:[9]

> The AEMC expects that the wholesale demand response mechanism and the ability for demand response aggregators to gain access to the wholesale electricity spot price will be completed by the end of this year. There may be some time allowed for underlying procedures and systems to be developed, before market commencement. Energy Networks Australia considers that this rule change will facilitate TNSPs partnering with these new market participants to develop and build scale solutions to meet identified transmission needs, including developing the hierarchy of use across the value chain as these new providers seek to develop the services market.

Consumers would ultimately fund the allowances under the DMIS and DMIA. These payments would increase total allowed revenue, which in turn would mean higher network charges for

6 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February2019, pp. 8–10.

7 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February2019, p. 8.

8 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February2019, pp. 20–21.

9 ENA submission to AEMC Consultation paper, 11 July 2019, p. 4

consumers at least in the short term. ENA considers that these costs would be outweighed by longer-term cost savings for consumers as a result of more efficient expenditure.

1.4 Solution proposed in the rule change request

ENA proposes to amend existing clauses and include new clauses in Chapter 6A of the NER, as well as amending clauses in Chapter 11 (Savings and transitional rules), as follows:[10]

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

1.5 Relevant background

The AER sets revenue and financial incentives for network businesses over a forward-looking period – usually five years. The allowed revenue is the basis for network charges, which are a component of electricity retailer bills. Network charges represent around 30 to 40 per cent of the average residential bill.[11]

The AER must take into account the price, quality, safety, reliability and security of supply of energy.[12] In addition, the AER must consider the revenue and pricing principles under the NEL, which support the NEO.

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

- a reasonable opportunity to recover at least their efficient costs of providing network services and complying with regulatory obligations
- effective incentives to promote economic efficiency.[13]

The NER require the AER to use the building blocks approach to determine how much revenue a network business needs to cover its 'efficient costs' over the coming regulatory period. The AER uses the building blocks approach to forecast and lock-in the total revenue that an efficient and prudent business would require. In doing so, the AER takes into account

10 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 23.

11 AER, State of the Energy Market 2018, p. 36.

12 See NEL Section 7.

13 See NEL Section 7A.

expected demand and cost inputs, all applicable regulatory obligations or requirements on the business, and the reliability, security and safety of the network (among other things).[14]

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

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

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

Transmission businesses must already apply a regulatory investment test for transmission (RIT-T) prior to making significant network investments.[15] The purpose of the RIT-T is to identify the transmission investment option that maximises net economic benefits and, where applicable, meets the relevant jurisdictional or electricity rule based reliability standards. Under the NER, in applying the RIT-T, a transmission business must consider all options that could reasonably be classified as 'credible options', including non-network solutions.[16] The RIT-T proponent, the transmission business, must consult on its 'project specification consultation report' and seek submissions from registered participants, AEMO and interested parties on the identified credible options.[17]

Each year, all transmission businesses are required to publish a Transmission Annual Planning Report, which must consider the potential for augmentations, or non-network alternatives to augmentations, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market (among other requirements).[18] There are similar requirements for distribution network service providers, although notably they have additional 'demand side engagement obligations' to develop a strategy for engaging with non-network providers and considering non-network options. Distributors must also engage with non-network providers and consider non-network options for addressing system limitations in accordance with its demand side engagement strategy.[19]

14 See NER Part C of Chapter 6 and Part C of Chapter 6A.

15 See NER clause 5.15 and 5.16.

16 See NER clause 5.15.2.

17 See NER clause 5.16.4.

18 See NER clause 5.12.1.

1.6 The rule making process

On 23 May 2019, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change request.[20] A consultation paper identifying specific issues for consultation was also published. The Commission received 11 submissions.[21] Issues raised in these submissions were summarised and responded to in the draft rule determination.

In response to the 12 September 2019 draft rule determination, the Commission received a further six submissions.[22] The Commission has considered all issues raised by stakeholders in submissions. These issues are discussed and responded to in the relevant sections of this final rule determination.

19 See NER clause 5.13.1.

20 This notice was published under s. [95 of the National Electricity Law (NEL)/303 of the National Gas Law (NGL)/251 of the National Energy Retail Law (NERL)].

21 Submissions were received from: AER, AGL, Australian Energy Council, EnergyAustralia, Energy Consumers Australia, Energy Efficiency Council, Energy Networks Australia (the proponent), ENGIE, Mondo, PIAC, and Government of South Australia.

22 Submissions were received from: AER, AGL, ENA, Energy Consumers Australia, PIAC and Government of South Australia.

2 FINAL RULE DETERMINATION

2.1 The Commission's final rule determination

The Commission’s final rule determination is to make a more preferable final rule. The more preferable final rule is to apply the DMIA, and not the DMIS, to transmission network service providers. A copy of the more preferable final rule is published with this final rule determination.

The key features of the more preferable final rule are:

- The AER must develop a demand management innovation allowance mechanism for transmission network service providers consistent with the demand management innovation allowance objective.[23]
- The objective of the demand management innovation allowance mechanism is to provide Transmission Network Service Providers with funding for research and development in demand management projects that have the potential to reduce long term network costs.[24]
- In developing and applying the mechanism, the AER must take into account the following:
  - the mechanism must be applied in a manner that contributes to the achievement of the demand management innovation allowance objective[25]
  - demand management projects should have the potential to manage ongoing changes in demand[26] and be innovative and not be otherwise efficient and prudent non-network options that a transmission network service provider should have provided for in its revenue proposal[27]
  - the level of the allowance should be reasonable considering the long term benefit to retail customers, should only provide funding that is not available from any other source, and may vary by transmission network service provider and over time[28]
  - the demand management innovation allowance may fund demand management projects which occur over a longer period than a regulatory control period.[29]
- Any demand management innovation allowance mechanism developed and applied by the AER must require transmission network service providers to publish reports on the nature and results of demand management projects that are the subject of the allowance.[30]

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23 See clause 6A.7.6(a) of the Amending Rule.

24 See clause 6A.7.6(b) of the Amending Rule.

25 See clause 6A.7.6(c)(1) of the Amending Rule.

26 This differs to the corresponding clause for distribution, which says ‘demand management projects should have the potential to *deliver* ongoing *reductions in demand or peak demand*…’ The broader reference to ‘*manage* ongoing *changes* in demand’ better accommodates possible network projects to address issues arising from the growth of solar PV exports and falling minimum demand.

27 See clause 6A.7.6(c)(2) of the Amending Rule.

28 See clause 6A.7.6(c)(3) of the Amending Rule.

29 See clause 6A.7.6(c)(4) of the Amending Rule.

30 See clause 6A.7.6(d) of the Amending Rule.

- The AER must develop and publish the demand management innovation allowance mechanism in accordance with the transmission consultation procedures by 31 March 2021.[31]
- There are also a number of amendments to existing clauses in chapter 6A of the NER to accommodate the demand management innovation allowance mechanism throughout the revenue determination process.[32]

2.2 Rule making test

2.2.1 Achieving the NEO

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(NEO).[33] This is the decision-making framework that the Commission must apply.

The NEO is:[34]

> 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.

2.2.2 Making a more preferable rule

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

In this instance, the Commission has made a more preferable rule. The reasons are summarised below in section 2.4.

2.2.3 Revenue and pricing principles

In addition to having regard to the NEO, the Commission must take into account the revenue and pricing principles when making a rule for or with respect to transmission system revenue and pricing.[35]

In making this final determination, the Commission has considered the following aspects of transmission system revenue and pricing to be most relevant:

31 See clause 6A.7.6(e) and the transitional rule of the Amending Rule.

32 See amendments to clauses 6A.4.2, 6A.5.4, 6A.6.6, 6A.6.7, 6A.8.2, 6A.10.1A, 6A.14.1, 6A.17.1 and S6A.1.3 of the Amending Rule.

33 Section 88 of the NEL.

34 Section 7 of the NEL.

35 Refer to section 88B of the NEL and Items 15 to 24 of Schedule 1 to the NEL.

- The regulation of revenues earned or that may be earned by owners, controllers or operators of transmission systems from the provision by them of services that are the subject of a transmission determination.[36]
- 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 transmission determination.[37]

As the more preferable final rule relates to such matters, the Commission must take into account the revenue and pricing principles. The revenue and pricing principles are set out in section 7A of the NEL.[38] The Commission considers the following revenue and pricing principles are the most relevant to the final rule:

- A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes:
  - efficient investment in a distribution system or transmission system with which the operator provides direct control network services
  - the efficient provision of electricity network services
  - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
- Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
- Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

In making this final determination, including the more preferable final rule, the Commission has taken the revenue and pricing principles into account.

The final rule enables the DMIA for transmission, which is expected to create effective incentives over multiple regulatory control periods for network businesses to undertake R&D on demand management projects – promoting economic efficiency. Electricity network demand management generally helps to remove or reduce network constraints and investment. Innovations that increase the viability of non-network solutions potentially provide a less costly alternative to capital investment and could lead to improved utilisation of the transmission system by, for example, shifting or reducing net demand on the network.

2.2.4 Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the

36 Item 15 of Schedule 1 to the NEL.

37 Item 17 of Schedule 1 to the NEL.

38 Section 7A of the NEL.

NEL.[39] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.[40]

As the Commission has determined to make a more preferable final rule which relates to parts of the NER that apply in the Northern Territory,[41] the Commission is required to consider whether to make a uniform rule or differential rule under Northern Territory legislation.

Under the NT Act, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[42]

A differential rule is a rule that:

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

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

A uniform rule is a rule that does not vary in its terms between the national electricity system and the local electricity systems, and has effect with respect to all of those systems.[43]

The Commission has determined to make a uniform rule as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.

Further details of the legal requirements for making this more preferable final rule are set out in Appendix A.

2.3 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 transmission 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 transmission businesses to identify and pursue

39 The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

40 The version of the NER that applies in the Northern Territory is available on the AEMC website.

41 While the final rule principally amends Chapter 6A, which does not apply in the Northern Territory, it also makes minor amendments in Chapter 6 and Chapter 10 of the NER, which do apply in the Northern Territory.

42 Section 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

43 Section 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

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 transmission businesses invest in and maintain their infrastructure. The regulatory framework should therefore aim to enable:
  - use of existing assets to be optimised
  - the network to be managed to meet changing demand
  - assets to be replaced at the end of their useful life if it is necessary and efficient to do so.
- **Transmission businesses are able to recover efficient costs**: The regulatory framework should only allow for an efficient level of costs to be recovered by transmission businesses, rather than allowing an automatic pass-through of all expenditure. This would promote efficient investment in transmission 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 transmission businesses should be incentivised to make improvements in efficiency.

The Commission's assessment has considered the extent to which the amendments proposed by ENA in its rule change request enable the AER to design and apply a DMIS and DMIA that supports these above conditions and, therefore, which promotes the NEO.

The amendments have been assessed against the relevant counter-factual arrangement. In this case, the counter-factual is the existing provisions in Chapter 6A of the NER.

In considering the rule change request, the Commission has separately analysed the DMIS and DMIA.

2.4 Summary of reasons

The more preferable final rule made by the Commission is published with this final rule determination.

Having regard to the issues raised in the rule change request and during consultation, the Commission is satisfied that the more preferable final rule to implement DMIA will, or is likely to, better contribute to the achievement of the NEO.

A range of views were expressed in submissions, but most stakeholders were not convinced of the benefits to consumers of introducing the DMIS in particular. The Commission accepts ENA's view that networks may face upfront, transitional costs to develop their ability to utilise non-network options. But we disagree on the best mechanisms to incentivise efficient non-network solutions.

In the Commission's view, introducing a DMIA for transmission creates a source of potential funding for networks to overcome the 'practical implementation barriers' of non-network alternatives and recover their efficient costs – in addition to the AER's approved revenue allowance and ARENA funded projects. Ongoing incentive payments to transmission businesses are not necessary to overcome implementation barriers.

A DMIA for transmission is expected to encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long term network costs and, consequently, could lower prices for consumers. Such innovation may play an important role in the transformation of the energy sector. The AER is expected to socialise network approaches and learnings by publishing DMIA reports for each transmission business on its website, as it currently does for distribution networks.

R&D can deliver overall benefits to consumers in the long term, but lead to higher costs in the short term. Regulated monopolies, like transmission businesses, inherently have less of an incentive to conduct R&D than competitive businesses. The nature of the regulatory control period imposed on networks, which 'resets' prices every five years or so, impacts the expected payoff of R&D projects. The DMIA addresses this issue under the regulatory framework.

The final rule provides the AER with discretion as to whether and how to apply the DMIA, including the level of the innovation allowance – consistent with ENA's proposal. This will support the AER in developing and applying an innovation allowance that is consistent with its objective, while being flexible and adaptable to future developments in the market and regulatory arrangements.

On the other hand, the Commission is not satisfied the DMIS promotes the NEO for the following reasons:

- It is not clear from the evidence presented by ENA that the incremental benefits of introducing a DMIS are likely to outweigh the upfront costs to consumers.
- If the DMIS is implemented, transmission businesses will receive incentive payments for undertaking non-network options that they already would have been required by the RIT-T to adopt.
- Ongoing incentive payments are not necessary to manage initial costs to transmission businesses to 'unlock' non-network solutions.
    - The RIT-T process and AER can take into account longer term dynamic efficiency gains that benefit consumers overall in considering any proposed expenditure to overcome practical implementation barriers. There is no 'incentive gap problem' under the current regulatory framework, as acknowledged by ENA.
    - Other sources of funding may be available too – such as from ARENA or, as a result of this decision, the DMIA.
- The Commission considers other possible benefits of the DMIS suggested by ENA do not outweigh the costs to customers:
    - The DMIS is not the most effective and direct way to promote a 'broader and deeper' market for non-network alternatives. Regardless, such industry subsidies may create inefficient market distortions and, therefore, are not necessarily warranted.

    - The proposed rule does not fundamentally address the potential risk of unbalanced incentives under the regulatory framework, which could bias investment decisions.
    - 'Cultural barriers' may exist in transmission businesses which mean they are resistant to or slow to adopt less familiar demand management approaches. The Commission is concerned that providing payments for networks through the DMIS (with no downside risk) to deliver efficient network services to the benefit of their customers, in addition to the existing ex-ante financial incentives, would promote a 'cost of service mentality' – negatively impacting dynamic efficiency and potentially hindering the market transition.
- On balance, the Commission's final rule determination is to make a more preferable final rule to apply the DMIA to transmission regulation, and not the proposed DMIS. This is supported by all stakeholder submissions to the draft determination, except for ENA.

3 ISSUES RAISED AND COMMISSION'S CONCLUSIONS

This chapter details the issues raised by ENA in its rule change request, issues raised in stakeholder submissions, and the Commission's analysis and conclusions. Specifically:

- Section 3.1 sets out the Commission's view that there is a significant risk that the application of the DMIS in particular would lead to higher costs to consumers and therefore does not promote the NEO.
- Section 3.2 sets out how the DMIA may promote innovation and efficient uptake of non-network solutions, in the long term interests of consumers.

3.1 The DMIS could increase costs to consumers without clear benefits

3.1.1 What is a 'practical implementation barrier'?

ENA's submission to the consultation paper states that rather than addressing an 'incentive gap problem' in the regulatory framework, its rule change addresses the absence of positive financial incentives for transmission businesses to adopt efficient non-network solutions to overcome 'practical hurdles' or 'practical implementation barriers'.[44]

Based on the rule change proposal and submissions to the consultation paper, the Commission interprets practical hurdles/implementation barriers to include establishing contract terms and conditions with non-network service providers, implementing internal business and communication protocols, and reputational and compliance risks associated with relying on a third party to deliver services. Reputational factors may include providing prescribed transmission services in a reliable and safe way, and being identified as providing efficient delivery of these services. ENA's explanation of practical hurdles/implementation barriers supports this interpretation:[45]

> This rule change proposal will facilitate building up possible non-network solutions, contractual terms and vendors for consideration in a timelier manner in regulatory investment processes. This is preferred to starting from a minimal base today and expecting a contract at scale to be commercially, technically and operationally viable when needed.
>
> NSPs' investment decisions to deploy non-network solutions are affected by considerations such as contracting and compliance risk relating to licence and other legislative obligations (including reliability obligations), along with the reputational risk that might arise from any non-compliance. As such it is important that TNSPs can build confidence with vendors that demand response has enough diversity, will be available when required and will be oversubscribed so that the required demand response can be achieved.

44 ENA submission to AEMC Consultation paper, 11 July 2019, p. 2.

45 ENA submission to AEMC Consultation paper, 11 July 2019, p. 3.

> The mechanisms to enable demand response and notify customers or DNSPs all need to be worked through as do the commercial terms and conditions. It would not be prudent or efficient to contract at scale and expect the required response without first building up confidence with vendors, communications and engagement processes for response, technology viability, durability and scale. Building enough maturity in the market for non-network solutions is a focus of the proposed rule change.

In the Commission’s view, these practical hurdles appear to be largely one-off costs or temporal. That is, once contracts and processes are established and trialled, the future costs of commissioning non-network option service providers would be lower and compliance risks largely mitigated.

This raises the question of whether ongoing incentive payments are necessary. Alternatively, the AER could provide direct funding for these initial ‘investment’ costs under the current regulatory framework, or other sources of funding may be available – such as from ARENA or, as a result of this decision, the DMIA.

Other ways to fund ‘initial hurdles’

AER revenue determinations can account for networks’ recovery of transactions costs, and the AER would consider the case for spending proposals to achieve dynamic efficiency gains that benefit consumers. In other words, the AER can fund (and has funded) network initiatives based on potential longer term savings to consumers. The Commission generally agrees with EnergyAustralia that the AER’s assessment of expenditures should recognise economic benefits that span multiple regulatory periods – including the role of option value in economic evaluations – and that this value may be significant in the current environment.[46]

ENA submits that funding through the AER's revenue allowances has not proven to be effective, given the lack of previous AER determinations where such funding has been approved.[47] As such, ENA says a dedicated incentive mechanism for demand management is needed for transmission networks.

No examples or evidence were cited by ENA whereby the AER had not approved proposals to fund efficient implementation costs for non-network solutions. The Commission is aware that the AER previously considered a TransGrid proposed opex ‘step change’ of $10.2 million for an increase in its so-called ‘demand management innovation allowance’ – which was in addition to the demand management expenditure already included in TransGrid’s ‘base year opex’.[48] TransGrid's proposal included costs for collaboration across the supply chain to overcome regulatory barriers to demand management, with the aim of facilitating a flexible demand management marketplace and to develop and grow the demand management market (among other initiatives and objectives).

The AER ultimately did not accept the proposed 'demand management innovation allowance' because it was not satisfied TransGrid had demonstrated that the system-wide benefits of the

46 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 3.

47 ENA submission to AEMC draft determination, 24 October 2019, pp. 3–4.

48 AER, TransGrid transmission determination 2014–18, Attachment 7 – Operating expenditure, p. 60.

proposed demand management program outweighed the costs, especially since TransGrid had significant spare capacity to meet peak demand. Further, there was no support from consumers for TransGrid's proposal – including by the Consumer Challenge Panel, which strongly opposed it.[49]

If the AER had discretion to apply the DMIS for this TransGrid decision, it seems unlikely that the AER would have come to a different conclusion. The test as to whether the DMIS should apply would likely be based on similar economic principles underlying the AER's expenditure assessment. For the DMIS applied to distribution, eligible projects must be the 'preferred option' to meet an identified need on the distribution network (that is, it must maximise the present value of the net economic benefit), have a positive NPV when assessed against the status quo (unless for reliability corrective action), and have been assessed as the preferred option through either the RIT-D or the 'minimum project evaluation requirements' (under clause 2.2.1 of the scheme, which sets out a less formal 'competitive testing' process).[50]

ARENA currently provides financial assistance to projects that accelerate the transition of renewable energy technologies along the innovation chain, from research and development to demonstration and large-scale pre-commercial deployment activities. In particular, ARENA aims to fund a range of flexible capacity technologies and mechanisms – from energy storage to demand response. Recent and relevant ARENA funded projects include:

- Ausgrid's 'Power2U' project, which involves the establishment a $4.1 million fund to help selected customers to permanently reduce their electricity use.[51]
- AEMO and ARENA demand response trial to provide 200 megawatts of emergency reserves for extreme peaks – ARENA committed $28.6 million in total to fund set-up and operational costs for the projects, with $7.2 million to be matched by the NSW Government for NSW-based projects.[52]
- United Energy demand response project, which will use voltage control devices installed at substations across its distribution network to deliver demand response.[53]

The DMIA scheme applied by the AER for distribution encourages the networks to direct their R&D funding towards projects that will promote demand management. Projects are required to be innovative and have the potential to reduce long-term network costs, whereby a project either:

- is based on new or original concepts – for example, a new or original ways of building or developing capability and capacity to undertake, facilitate or utilise demand management
- involves technology or a technique not previously implemented in the relevant market, or

49 AER, TransGrid transmission determination 2014–18, Attachment 7 – Operating expenditure, pp. 60–62.

50 AER, Demand management incentive scheme – Explanatory statement, Electricity distribution network service providers, December 2017.

51 See: https://arena.gov.au/projects/ausgrid-power2u/

52 See: https://arena.gov.au/news/aemo-arena-demand-response/

53 See: https://arena.gov.au/projects/united-energy-distribution-demand-response/

- is focussed on customers in a market segment that has not been exposed to the technology.[54]

Projects that seek to increase the networks' flexibility to adopt non-network options could meet these above criteria, if applied to transmission. ENA submits a DMIA may prove sufficiently flexible for innovation and pure research, but may not be sufficient to prove and build up scale solutions with potential demand response providers, including gaining customer buy-in to such solutions.[55]

3.1.2 Risk of net costs to consumers

A common theme in submissions is strong support for efficient demand management solutions that reduce the need for investment in transmission and distribution infrastructure. However, it is not clear from the evidence presented by ENA that the incremental benefits of introducing a DMIS are likely to outweigh the upfront costs to consumers – as questioned by some stakeholders. For example:

- The South Australian Government recognises the potential for efficient non-network solutions to provide benefits for consumers. However, it considers the ENA rule change request has not adequately established the case that applying the DMIS for transmission networks is a preferred mechanism to incentivise efficient non-network solutions.[56]
- Energy Consumers Australia submits that no case has been made by ENA for the payment of DMIS: 'We remain convinced that the incentive offered by DMIS is inconsistent with the requirement to consider non-network solutions in the RIT-T process.'[57]
- AGL states: 'Under the existing regulatory framework, transmission networks must consider non-network options (including demand management projects) when considering the lowest cost option to meet changing demand. AGL agrees with the AEMC that this indicates that a DMIS is unnecessary and may add additional costs for customers over the long-term.'[58]
- The AER stated that the DMIS for distribution remains largely untested, so it is not in a position to conclude how effective the current DMIS or DMIA are in achieving their objectives.[59]

In its initial submission, PIAC supported ENA's proposal to strengthen the incentive for transmission businesses to pursue non-network options through the DMIS.[60] However, in response to the draft determination, PIAC now submits:[61]

54 AER, Demand management innovation allowance mechanism: Electricity distribution network service providers, Explanatory statement, December 2017, p. 6.

55 ENA submission to AEMC draft determination, 24 October 2019, p. 4.

56 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1; and submission to AEMC draft determination, 14 October 2019, p. 1.

57 ECA submission to AEMC draft determination, 28 October 2019, p. 1.

58 AGL submission to AEMC draft determination, 24 October 2019, p. 1.

59 AER submission to AEMC Consultation paper, 11 July 2019, p. 2.

60 PIAC submission to AEMC Consultation paper, 10 July 2019, p. 1.

61 PIAC submission to AEMC draft determination, 22 October 2019, p. 2.

> ... we do not consider it currently prudent to extend the current DMIS framework (as it applies to DNSPs) to TNSPs. Instead, if there are systemic biases against demand management and other non-network options in transmission planning or more effective ways to deliver prudent non-network alternatives, this should be investigated separately such as through the AEMC's Electricity Network Economic Regulatory Framework (ENERF) review. From this an appropriate mechanism could be developed specific to TNSPs.

A significant risk with the DMIS is that consumers would potentially fund ongoing incentive payments to manage 'barriers' that have already been overcome.

In the Commission's view, if the DMIS is extended to transmission as proposed, transmission businesses will receive incentive payments for undertaking non-network options that they already would have been required by the RIT-T to adopt. If the net benefits of a non-network solution (including any quantifiable costs of 'practical hurdles') are greater than a capital investment option, the transmission business is expected to adopt the non-network solution as the 'preferred option'[62] – as required by the RIT-T and/or incentivised by the ex ante regulatory framework under a revenue cap (including the EBSS/CESS/STPIS). Under this scenario, consumers will not benefit from the DMIS. The incentive payments would transfer benefits from consumers to the transmission business, and potentially lead to higher consumer prices overall.

This is a significant risk given examples highlighted in submissions of transmission businesses already successfully utilising demand-management approaches:

- The South Australian Government submitted there is evidence that existing incentives and mechanisms are supporting transmission businesses to investigate and implement non-network solutions such as generation, energy storage and demand response – citing Dalrymple Battery Project and Port Lincoln generation network support arrangements.[63]
- AEC highlighted TransGrid procured 350 MW of demand management in 2007-08 in the Sydney-Newcastle-Wollongong area, enabling it to defer construction of the Western 500 kV Project for one year. Further, AEC submits TransGrid partnered with EnerNOC to deliver a demand management project involving more than 80 sites across metropolitan Sydney, which saw a reduction of peak demand for the summer of 2012-13 by a total of 48 MW.[64]
- AGL highlighted TransGrid recently successfully applied a non-network solution under the Powering Sydney's Future program, which it says infers introducing further incentive mechanisms for demand management may be unnecessary and could add additional costs for consumers.[65]

62 Under the RIT-T, the 'preferred option' is the 'credible option' that maximises the net economic benefit across the market, compared to all other credible options. The net economic benefit of a credible option is simply the market benefit less the costs of the credible option.

63 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1.

64 AEC submission to AEMC Consultation paper, 10 July 2019, pp. 2–3.

65 AGL submission to AEMC Consultation paper, 11 July 2019, p. 2.

- ENA submitted that under TransGrid's Powering Sydney's Future project, a $250m project was able to be economically deferred using non-network solutions.[66]

Moreover, Mondo submitted:[67]

> TNSPs are currently exploring numerous options for how best to respond to the energy transformation challenges. For example, TNSPs are already exploring options for utilising grid connected storage as a means of avoiding load shedding in the event of overloads, thereby delaying network augmentation. TNSPs are also keen to examine how battery storage can be utilised to provide load management services, as well as their potential to contribute system strength and frequency control capability. Another example of TNSP interest is in seeking to use various load management techniques to optimise the utilisation of existing interconnector capability.

TransGrid said it is actively developing the demand management market in response to the customer perception that transmission networks do not actively pursue non-network alternatives and that the process during a RIT-T can be seen as a 'tick box' exercise. TransGrid acknowledges this concern and states it is working hard to satisfy customers that a non-network solution will be pursued wherever feasible and efficient.[68]

ENA says that consumers would be better off by incentivising network businesses through a DMIS to 'look for and deliver' non-network alternatives.[69]

ENA's argument, it seems, is that the net benefits of a non-network solution may be less than a capital investment option in the short term. But longer term, consumers could benefit from dynamic efficiencies such that the overall costs of non-network options are significantly lower in the future – as the market develops, and transmission businesses overcome the 'practical implementation barriers'. ENA states:[70]

> While TNSPs currently have the obligation under the RIT-T to pursue non-network solutions under the current arrangements, they have little incentive to do so. The barrier to pursue non-network solutions and build capability with demand response providers is therefore currently higher than it should be ...
>
> ... The introduction of a DMIS will facilitate a greater use of efficient demand management which will result in benefits to consumers. While incentive payments would ultimately be funded by consumers, Energy Networks Australia expects these costs to be modest relative to the long-term cost savings brought about by increased use and availability of efficient non-network solutions.

66 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 9.

67 Mondo submission to AEMC Consultation paper, 11 July 2019, p. 2.

68 TransGrid, Revenue Proposal 2018-19–2022-23, January 2017, p. 46.

69 ENA submission to draft determination, 24 October 2019, p. 4.

70 ENA submission to draft determination, 24 October 2019, p. 4.

However, ENA does not explain why the RIT-T process and the AER cannot take into account longer term dynamic efficiency gains that benefit consumers overall.[71] The Commission expects such factors would be taken into account in deciding on the 'preferred option' or in determining an expenditure allowance – consistent with the national electricity objective to promote the long term interests of consumers.

Even if not, for the distribution DMIS applied by the AER which ENA proposes to extend to transmission, eligible projects must be the 'preferred option' to meet an identified need on the distribution network. That is, the DMIS would only be applied to projects that are already required by the RIT-T (or the 'minimum project evaluation requirements' as defined under the DMIS for lower cost projects). As such, it is difficult to come up with a scenario in which consumers could benefit from transmission businesses utilising more efficient non-network solutions that wouldn't have otherwise been adopted, if not for positive incentives created by the DMIS.

As ENA explains in its response to the draft determination:[72]

> The AEMC's concern that networks may be incentivised to adopt non-network solutions that are more expensive than network solutions as a result of DMIS incentive payments, does not reflect how the scheme would operate in practice. This is because under the DMIS, networks would only be eligible for incentive payments for non-network solutions that are the preferred (i.e. the most efficient) solution. Therefore, networks would not be incentivised to adopt higher-cost non-network solutions – these solutions would not be eligible for DMIS incentive payments.

Better ways to promote the developing market for non-network services

In support of ENA's view that the DMIS and DMIA will assist the development of the non-network industry more broadly, EnergyAustralia submitted that networks may not adequately consider benefits across the whole value chain for electricity when making investment decisions – and therefore undervalue non-network solutions. EnergyAustralia suggested the Commission should investigate the extent to which transmission networks overlook market-wide benefits in practice.[73]

PIAC submitted:[74]

> … we consider there is a role to build a large, diverse and readily accessed pool of DR throughout each NEM region (including directly contracting with customers or via an aggregator or retailer). By such "market building" procurement, the collective pool could be called on to meet other potential value streams of DR far more efficiently and reliably than the current arrangements that lack coordination between the possible

71 Under the RIT-T, 'externalities' are not included in either the costs or market benefits of a credible option and are therefore not included in the determination of net economic benefit. But externalities are defined as economic impacts that accrue to parties *other than* those who produce, consume and transport electricity in the market (see NER clause 5.16.1(c)(9)).

72 ENA submission to draft determination, 24 October 2019, p. 4.

73 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 1.

74 PIAC submission to AEMC draft determination, 10 July 2019, p. 2.

> value streams. This could build a greater pool of cost-effective resources for the future, expanding the range of options for future market design and system operation strategies.

In the Commission's view, providing incentive payments through the DMIS to networks to pursue demand-side solutions would only indirectly promote a 'broader and deeper' market for non-network alternatives. ENA did not attempt to quantify these 'trickle-down' benefits to consumers in its rule change request.

This objective would be more effectively achieved through an innovation allowance, such as the DMIA or ARENA funded projects, or possibly direct government subsidies (for example, by providing discounted financing costs for new start-ups). Any such government policy would be based on a deep market analysis to justify intervention. Alternatively, new requirements could be imposed on transmission businesses to develop a strategy for engaging with non-network providers and considering non-network options (see demand side engagement obligations applied to distributors under NER clause 5.13.1).

In any case, imposing advantages for certain market competitors through subsidies, especially in the absence of clearly identified positive externalities, may inefficiently distort investment signals and dull competitive pressures. Regulation should not be about 'picking winners' – it is better to allow the market to 'decide' than for the regulator or the policy-maker to favour a particular technology or solution and have customers carry the risk.[75]

PIAC submits: 'We encourage the AEMC to explore options to help build a larger and more resilient market for DR such as through the AEMC's Electricity Network Economic Regulatory Framework (ENERF) review.'[76]

Are consumers willing to fund this investment?

ENA has positioned consumers or end customers to be the main beneficiary of the DMIS. However, ENA did not provide evidence that consumers are willing to accept higher upfront charges to fund the proposed incentive payments to networks – with the prospect of at least lower future network charges as non-network options become more readily available and implementable. In its response to the draft determination, ENA notes the mixed response from consumer groups on the rule change request at that time.[77]

The AER submitted there needs to be evidence of consumer support for extending the DMIS (and DMIA) to transmission, noting consumer support was a key factor in the introduction and design of the distribution schemes.[78]

The AER stated:[79]

75 See: https://www.aer.gov.au/news/networks-must-deliver-better-outcomes-for-consumers/perspectives-on-regulation-in-a-changing-environment-what-does-%E2%80%98success%E2%80%99-look-like-in-energy-regulation

76 PIAC submission to AEMC draft determination, 22 October 2019, p. 2.

77 ENA submission to AEMC draft determination, 24 October 2019, p. 4.

78 AER submission to AEMC Consultation paper, 11 July 2019, pp. 2–3.

79 AER submission to AEMC Consultation paper, 11 July 2019, p. 2.

> A DMIS and DMIA rely on consumers funding incentive and allowance payments in the short term in the expectation of longer term benefits through improved take-up of efficient demand management options. For that reason, we consider consumer support for this rule change request is critical.

The Commission received two submissions from consumer representatives to the draft determination. Both Energy Consumers Australia and PIAC do not support ENA's proposal to extend the DMIS to transmission. Energy Consumers Australia added:[80]

> ... the Proposal included no details of any consultation undertaken by the proponents before lodging the request. In saying that we could not support the proposed rule [in Energy Consumers Australia initial submission] we noted we remained open to further consultation with Energy Networks Australia if they want to demonstrate alternatives that they considered and why they were rejected. There has been no approach to us by Energy Networks Australia in this regard.

3.1.3 Does the rule change help to balance incentives under the regulatory framework?

The Commission has considered the extent to which the rule change request relates to the Commission's exploration of alternative models for network incentives and revenue-setting (eg, 'totex' approaches) to manage the risk of unbalanced incentives under the regulatory framework – as part of the *2019 Economic regulatory framework review*. This broader consideration was supported by stakeholders in several submissions.[81]

ENA stated that its rule change proposal addresses an imbalance of incentives that currently exists when pursuing demand management projects. It considers the lack of positive incentives for non-network options potentially creates a bias towards network capital investment under the current rules, and this has the potential to result in transmission businesses not having a sufficient incentive to undertake efficient non-network investment.[82]

The Commission considers the rule change does not fundamentally address the risk of unbalanced incentives leading to capex bias.

DMIS would not address the underlying cause of unbalanced incentives

'Practical implementation barriers' to take-up non-network options, as described by ENA, were not a significant factor in the Commission's finding in the *2018 Economic regulatory framework review* that the regulatory framework creates unbalanced incentives between capex and opex solutions. The Commission concluded that the misalignment of incentives is due largely to the current method of separate assessment and remuneration of opex and capex.[83]

80 ECA, Submission to AEMC draft determination, 28 October 2019, p. 2.

81 Including submissions from AGL (pp. 1–2), EnergyAustralia (p. 1), ENGIE (p. 2) and Mondo (pp. 2–3). EnergyAustralia suggests exploration of further incentive issues and overseas models (p. 3), which the Commission will consider as part of the Economic regulatory framework review.

82 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 26.

83 AEMC, 2018 Economic regulatory framework review, July 2018, p. 36.

The Commission found the risk of unbalanced incentives may distort investment decisions where a network service provider may choose a solution that would provide the greatest financial returns instead of the most efficient solution.[84]

Even if a totex framework applied under the regulatory framework, the 'practical hurdles' of non-network alternatives would still create additional 'investment' costs that would be weighed by the business against the total costs of an alternative capex solution. That is not a distortion. It is comparing the costs/risks of possible solutions to identify the least cost option overall.

A primary example of an inefficient distortion is when a network business prefers a capex solution because its expected cost of capital is lower than the regulated cost of capital, which means the capex solution would provide the greatest financial return – all other costs being equal between a network and non-network solution.

Stakeholder submissions came to a similar conclusion. For example, AEC submitted:[85]

> Whilst the AEC encourages the use of DM alternatives, which can unequivocally deliver lower prices for consumers, the question of capex over opex bias in the investment decisions of transmission networks is not actually answered by DMIS arrangements. For these reasons we do not support the use of cost uplift for such projects.

AGL stated:[86]

> … this rule change was proposed to address the issue that there is a bias towards investment in CAPEX projects instead of non-network options. While we support networks being encouraged to engage efficient non-network options, including demand management, we consider the AEMC should consider the issue more broadly. It would be more cost-effective to address the underlying problem related to incentives rather than introducing a specific incentive mechanism for demand management.

EnergyAustralia submitted:[87]

> The ENA highlights potential barriers to pursuing non-network solutions however in some cases these reflect imbalances between incentives for capital and operating expenditures. These imbalances would not be effectively addressed through demand management incentives.

ENGIE considered that the introduction of a DMIS/DMIA incentive scheme for transmission is not warranted purely on the basis of attempting to align capex and opex incentives.[88]

84 AEMC, 2018 Economic regulatory framework review, July 2018, p. 34.

85 AEC submission to AEMC Consultation paper, 10 July 2019, pp. 1–2.

86 AGL submission to AEMC Consultation paper, 11 July 2019, pp. 1–2.

87 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 3.

88 ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 3.

3.1.4 Cultural factors

In its rule change request, ENA both notes other stakeholder views that the DMIS would help to address the 'cultural barriers' within network businesses to assessing demand management, and references the Commission's *2018 Economic regulatory framework review* finding that cultural issues appear to contribute to a capex bias in certain circumstances.[89]

The suggestion is that incentive payments (combined with profit maximising objectives) may promote positive change to network businesses' internal culture to be more flexible and innovative, which could have significant longer term benefits to consumers.

The DMIS may complement other recent initiatives to improve the culture of the sector, such as:

- Industry led awards recognise leadership in consumer engagement and innovation by network businesses. This has helped to build knowledge of successful engagement approaches, and created strong reputational incentives and rivalry among the businesses – driving innovation and experimentation.
- The Energy Charter, which seeks to progress the culture and solutions required to deliver a more affordable, sustainable and reliable energy system: "It is focused on embedding a customer-centric culture and conduct in energy businesses to create tangible improvements in affordability and service delivery."[90] Signatories are publicly accountable for delivering against its five underlying principles to provide improved outcomes for customers.

EnergyAustralia submitted the Commission should explore the claim from ENA that networks have a 'cultural' bias against non-network solutions:[91]

> Knowing the root cause of this bias is important in designing an effective solution, and could be one or a combination of:
>
> - unusual counter-party risk or the market for non-network services being immature
> - a general reluctance of some TNSPs to partner with non-network service providers
> - poor valuation of non-network alternatives based on a cost of capital approach, rather than present value of avoided network costs over the life of the assets being deferred
> - shortcomings in consultation processes that prevent proponents from being appropriately engaged (e.g. regulatory investment tests, transmission determinations etc).

89 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 9; 30.

90 The Energy Charter, January 2019, p. 1.

91 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 3.

Extrinsic motivations can negatively impact intrinsically motivated behaviours

ENA stated transmission businesses receive no reward for implementing efficient non-network options.[92] At the same time, ENA said non-network solutions have an increasingly important role to play, and increased uptake of efficient non-network solutions is expected to benefit customers through lower transmission and total system costs.[93]

The Commission is concerned that providing payments for networks through the DMIS (with no downside risk) to deliver efficient network services to the benefit of their customers, in addition to the existing ex-ante financial incentives, would promote a 'cost of service mentality' – negatively impacting dynamic efficiency and potentially hindering the market transition.

AEC submitted that providing additional financial incentives for transmission businesses to undertake demand-side investments means that future action will occur only when they are inefficiently generous, and this is not the best approach to address the cultural and commercial biases to invest in capex.[94]

ENGIE submitted the implication of ENA's proposal is that transmission businesses will hesitate to undertake non-network options, even when they are cheaper, because of their unfamiliarity with such options and therefore how they will work out. However, ENGIE said that under the current regulatory framework networks already have clear financial incentives to choose the cheaper option because they retain a share of the savings: 'It's not clear then, that an additional incentive is the best solution to such an issue.'[95]

Energy Consumers Australia submitted:[96]

> In the current environment the biggest reputational risk to all NSPs is the perception that they have no separate interest in fulfilling the NEO and in particular in helping to reduce costs to consumers, but instead can only be expected to act in the interest of consumers in response to a specific identified financial incentive. The Proposal seems to reflect that position.

What would be expected in a competitive environment?

The regulatory framework seeks to emulate workably competitive market outcomes and promote a competitive mindset/culture in networks to an extent. For example, the expectation is that network businesses should seek out new ways to improve operations and service quality to the benefit of consumers, rather than preferring a 'quiet life'. Although somewhat abstract, competitive-market outcomes provide a useful efficiency benchmark.

92 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 26.

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

94 AEC submission to AEMC Consultation paper, 10 July 2019, p. 3.

95 ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 2.

96 ECA submission to AEMC Consultation paper, 15 July 2019, p. 2.

It is arguable that the practical hurdles/implementation barriers described by ENA are 'business-as-usual' costs that do not require separate, additional funding. Under the incentive-based regulatory framework, networks are expected to manage the inevitable 'ups and downs' in expenditure components from year-to-year (to the extent they do not offset each other) by continually re-prioritising their work programs – as would be expected in a competitive market. Non-network solutions offer the transmission businesses valuable options to manage change and respond to new challenges.

ENGIE submitted:[97]

> Businesses under the pressure of competitive forces frequently have to adapt their operations in order to reduce their costs or improve their product or service. To the extent that they are trying out approaches that are new to them, this could be considered in the broadest sense "innovation" but is also a normal part of business.

Further, ENGIE argued the regulatory framework is not predicated on fully de-risking the networks – otherwise they could be financed on fully risk-free terms:[98]

> Accordingly, the simple decision between a more familiar capex solution and a less familiar but potentially cheaper opex solution should not warrant an additional incentive.

3.1.5 Distribution vs. transmission, and the impact of the RIT-T

Commencing 1 January 2008, chapter 6 of the NER included the demand management incentive scheme for distribution.

A 2007 rule change request by the Total Environment Centre proposed the development of a demand management incentive scheme for transmission (among other things).[99] The Commission did not agree with the proposal. We considered a revenue cap provides strong incentives for the transmission businesses to minimise costs because a regulated business is able to earn larger profits by reducing costs, and demand management can be an effective way for them to reduce costs. Further, the Commission stated that in contrast to a price cap (which applied to distributors at the time), under a revenue cap the network is not exposed to the loss of revenue associated with a reduction in usage at peak time.[100]

In 2015, the Commission made the *Demand management incentive scheme rule* in response to rule change requests submitted by the COAG Energy Council and the Total Environment Centre. This rule change made amendments to the existing demand management arrangements to:

- create separate provisions for a demand management incentive scheme and a demand management innovation allowance mechanism

97 ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 2.

98 ENGIE submission to AEMC Consultation paper, 20 June 2019, pp. 2–3.

99 Total Environment Centre, Rule change proposal – demand management and transmission networks, 6 November 2007.

100 AEMC, Demand Management, Rule Determination, April 2009, p. 32.

- introduce an objective for the incentive scheme, and a separate objective for the innovation allowance.
- introduce 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.
- require the AER to develop and publish the incentive scheme and innovation allowance in accordance with the distribution consultation procedures.[101]

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

- transmission businesses could, and had, contributed to effective demand management – albeit in a more limited capacity compared to the demand side and distribution side
- transmission businesses were already required to consider the potential for demand management options (non-network options) under the RIT-T
- the AER could already provide funding for non-network solutions under the regulatory framework through the operating expenditure allowance (and had done so)
- ultimately, consideration of the application of the DMIS and DMIA for transmission network regulation was out of scope of the rule change proposal.[102]

A greater proportion of projects are likely to be subject to the RIT in transmission compared to distribution, given the lumpier nature of transmission investments. The RIT-T rules and related AER guidelines promote consultation and consideration of all credible options to address an investment need – including a transparent process for non-network service providers to propose alternative solutions.

Transmission businesses are required to consult all registered participants, AEMO and interested parties on a RIT-T project – including preparation of a consultation report that outlines the technical characteristics of the identified need that a non-network option would be required to deliver.[103]

A transmission business must apply the RIT-T to all proposed transmission investment except where a proposed investment is required to address an urgent and unforeseen network issue, or the estimated capital cost of the most expensive option to address the identified need is which is technically and economically feasible is less than $6 million – among other factors. Where a transmission business does not need to apply the RIT-T to a proposed investment, a transmission business must ensure, acting reasonably, that the investment is planned and developed at least cost over the life of the investment.[104]

ENA submitted the nature and scale of transmission projects means that, while the scale of non-network solutions required to address transmission-level network constraints may be

101 AEMC, Demand management incentive scheme, Rule Determination, August 2015, p. iii.

102 AEMC, Demand management incentive scheme, Rule Determination, August 2015, pp. 27–28.

103 NER clause 5.16.4(b).

104 Clause 5.16.3(a)(2) of the NER states a figure of $5 million, but the AER's latest cost threshold determination, conducted in accordance with clause 5.15.3 of the NER, has specified that a RIT-T applies where the capital cost exceeds $6 million.

more challenging than at the distribution-level, the potential benefit of deferred network investment is commensurately larger.[105] ENA said its rule change request is complementary to the RIT-T, as the application of the DMIS and DMIA could result in more non-network solutions being viable through the promotion of a more mature non-network solution market.[106]

In response, Energy Consumers Australia submitted that if a transmission project is sufficiently large for the impact on prices to be material, the investment will need to satisfy the RIT-T.[107] Further:[108]

> If there is a viable non-network solution, as is assumed in the case for the DMIS, then the network solution would not meet the requirements of the RIT-T and the TNSP would be required to implement the non-network solution to meet the requirements of their licence, which would seem to be incentive enough.

AEC said transmission networks are already required to consider non-network options and if they are failing to do so, the proposed rule change is not a prudent way to address this bias.[109]

EnergyAustralia submitted justification for applying demand management incentives to distributors may not apply to transmission because they face different circumstances – for example, the diversity of projects on distribution networks may mean that there are less individual commercial-scale demand management opportunities for distributors than transmission businesses.[110] In contrast, ENA said it is not aware of any evidence that non-network solutions are any less viable for transmission than distribution.[111]

The Commission maintains that transmission businesses have a more limited ability or fewer opportunities to utilise demand management solutions, compared to distribution, due to the challenges presented by the large scale of transmission projects – as acknowledged by ENA above. We are closely monitoring the outcomes of the DMIS for distribution, which will inform the AER's ongoing application of the scheme.

The South Australian Government said the proposal has not fully explained why non-network solutions are not adequately incentivised through existing business practices, market mechanisms and trial support mechanisms – such as the RIT-T, Network Support and Control Ancillary Services and trial support mechanisms such as ARENA funding.[112] Further:[113]

> ... the DMIS and DMIA were made in a period of broader reform to incentive (sic) non-

105 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 9.

106 ENA submission to AEMC Consultation paper, 11 July 2019, p. 2.

107 ECA submission to AEMC Consultation paper, 15 July 2019, p. 2.

108 ECA submission to AEMC Consultation paper, 15 July 2019, p. 2.

109 AEC submission to AEMC Consultation paper, 10 July 2019, p. 3.

110 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 4.

111 ENA submission to AEMC Consultation paper, 11 July 2019, p. 3.

112 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1.

113 Government of South Australia (Department of Energy and Mining) submission to AEMC Consultation paper, 12 July 2019, p. 1.

network options for distribution networks. Changes included new requirements for network prices that reflect the efficient cost of providing network services to individual consumers, which are still in the process of being implemented. The Division notes that a significant driver of the AER applying DMIS and DMIA is to form a bridge to a framework more focussed on efficient pricing of distribution network services. This driver does not appear to exist for transmission network services, noting efficient prices have not been identified as an issue for transmission connected customers and for distribution connected customers the issue is addressed through the DMIS and DMIA. The view of the Australia Energy Regulator would be valuable on these specific issues.

3.2 ENA proposal objectives can be achieved through innovation allowance

The Commission accepts ENA's view that networks may face upfront, transitional costs to develop their ability to utilise non-network options. But we disagree on the best mechanisms to incentivise efficient non-network solutions. As discussed above, the Commission considers a DMIS is not warranted. Stakeholder submissions to the draft determination, including by the AER, AGL, Energy Consumers Australia, PIAC and South Australian Government, support the decision to only introduce a DMIA for transmission.

Introducing a DMIA for transmission creates a source of potential funding for networks to overcome to an extent the 'practical implementation barriers' of non-network alternatives and recover their efficient costs – in addition to the AER's approved revenue allowance and ARENA funded projects. Ongoing incentive payments to transmission businesses are not necessary to overcome implementation barriers.

Further, the DMIA is expected to encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long term network costs and so prices for consumers. R&D can deliver overall benefits to consumers in the long term.

Consistent with this view, EEC submitted there appears to be a reasonable case for providing transmission businesses with a DMIA, but it is less clear if they already have good incentives to invest in demand management, or whether they will need access to a DMIS.[114] EnergyAustralia said a justification of the rule change, which essentially creates a subsidy, is to accelerate and enable demand management deployment – but any such subsidy should be time-limited and exist for the purposes of overcoming deployment barriers, such as high cost or risks to the network, rather than correcting incentive issues.[115]

114 EEC submission to AEMC Consultation paper, 19 July 2019, p. 2.

115 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, p. 2.

3.2.1 Promoting innovation

Innovation can improve allocation of resources over time, which can in turn reduce long term costs. Innovation may also improve the ability of networks to adapt efficiently to changed economic conditions. Such dynamic efficiencies often involve a trade-off. R&D may lead to higher costs in the short run. But, without this investment and innovation, the network businesses may be unable to find progressively better ways of providing network services.

In its submission to the consultation paper, Mondo stated:[116]

> The current rapid rate of transition which is being experienced in the energy sector has increased the need for industry participants to be innovative in their approach to problem solving. In the past, it was feasible for industry participants to take a cautious approach to change, and carefully examine any past examples as learning opportunities. The current paradigm however means that there are few if any past examples to provide learning opportunities, and participants are therefore required to take additional risks in implementing innovative solutions to new problems.

R&D requires investment costs to be incurred by the network business and the 'payoff' is generally uncertain. Regulated monopolies like network businesses arguably have less of an incentive to conduct R&D than competitive businesses. This is because networks face lower 'up-side risk' given they cannot by definition gain a 'competitive advantage'. Moreover, to the extent that R&D results in future cost reductions, networks will pass a material portion of these gains onto electricity consumers through incentive regulation. Additionally, networks still face 'down-side risk' – if R&D costs occur significantly before the benefits, the businesses risk being financially penalised from making these decisions under the EBSS and/or CESS. ENGIE submitted:[117]

> To the extent that TNSPs need to carry out specific "research and development" activities (as opposed to merely being prepared to adapt to previously unfamiliar ways of doing business) in order to be able to substitute in non-network options for network options, then the case for some regulatory support is stronger. In Great Britain, where the CPI-X style regulatory framework has been applied for longer than in Australia, it was observed some time ago that the framework was good at driving efficiency, including certain types of innovation that typically resulted in a clear payoff over a short time frame, but inhibited research and development into longer-term issues where the chance of success of any given project was lower, and the network's opportunity to retain the benefits of success was curtailed.

The AER can fund R&D costs through the opex allowance, so there is not necessarily a gap in the current regulatory framework. Nevertheless, the Commission considers there are benefits to formalising this arrangement and for the AER to better socialise sector approaches and learnings – capturing the positive externalities of innovation. For the distribution DMIA, the

116 Mondo submission to AEMC Consultation paper, 11 July 2019, p. 1.

117 ENGIE submission to AEMC Consultation paper, 20 June 2019, p. 3.

AER publishes the network businesses compliance reports on its website as a 'one-stop-shop'[118] to allow third parties to more easily compare and contrast options.[119]

As stated by ENA: [120]

> The rule change proposal will provide a certain and robust reporting framework for demand management which will allow TNSPs to take a more proactive approach in innovation and research and pursue developments in this area. This will provide more visibility for consumers over how TNSPs are using these arrangements to lower total system costs through the specific information provided to and published by the AER.

PIAC considers that although the AER can approve 'innovation allowances' under the current regulatory framework (such as for TransGrid), a formal mechanism would be beneficial to all stakeholders by providing greater certainty to both the AER and networks in terms of the criteria innovation projects must meet in order to qualify. Further, PIAC said it would provide greater certainty that the lessons and insights from the innovation projects would be shared publicly.[121]

3.2.2 Implementation of the DMIA to transmission

ENA proposes to apply the current distribution DMIA to transmission, including for the AER to have discretion in how it designs and applies the DMIA for transmission businesses.[122]

No stakeholder submissions questioned the wording of the distribution DMIA rules or whether the AER should have significant discretion to apply the DMIA for transmission businesses, as proposed by ENA. However, submissions from AGL,[123]AEC,[124] EnergyAustralia,[125] the Energy Efficiency Council,[126] and ENGIE[127] raised issues with how the schemes should be designed by the AER, and highlighted interrelationships with other regulatory mechanisms – especially ring-fencing guidelines for transmission. These issues may be considered by the AER.

AGL suggests that the Commission should include a transitional rule for the AER to review and update the transmission networks ring-fencing guideline by 31 December 2020 – before these businesses are provided with greater incentives to engage demand management

118 For example, see: https://www.aer.gov.au/networks-pipelines/compliance-reporting/demand-management-innovation-allowance-dmia-assessment-2016-17-and-2017

119 Clause 6.6.3A of the NER says: 'Any mechanism developed and applied by the AER must require Distribution Network Service Providers to publish reports on the nature and results of demand management projects the subject of the allowance.' To give effect to this, it appears the AER requires the distribution businesses to submit compliance reports to it in a form that is capable of being published by the AER – with the intention of then publishing the reports on its website to 'increase the usefulness and accessibility of each project report'. (AER, Demand management innovation allowance mechanism: Explanatory statement, December 2017, p. 26.) The Commission expects that AER would adopt a similar approach for transmission.

120 ENA submission to AEMC Consultation paper, 11 July 2019, p. 4.

121 PIAC submission to AEMC Consultation paper, 10 July 2019, p. 1.

122 ENA, Demand Management Incentive Scheme and Demand Management Innovation Allowance – Rule Change Request, February 2019, p. 6.

123 AGL submission to AEMC Consultation paper, 11 July 2019, p. 3; and submission to AEMC draft determination, 24 October 2019, p. 2.

124 AEC submission to AEMC Consultation paper, 10 July 2019, p. 2; 4.

125 EnergyAustralia submission to AEMC Consultation paper, 11 July 2019, pp. 3–5.

126 EEC submission to AEMC Consultation paper, 19 July 2019, p. 2.

127 ENGIE submission to AEMC Consultation paper, 20 June 2019, pp. 3–4.

services.[128] The AER recently released a discussion paper to commence a review of ring-fencing arrangements for transmission networks, with a final guideline expected to be published by September 2020.[129]

The AER submitted that if a rule change is approved, it would require sufficient flexibility to consult on and develop a scheme and mechanism for transmission businesses, including its design, implementation timeframe, and application.[130] Further:[131]

> We consider further analysis of the existing regulatory framework as it relates to TNSPs is necessary before the specific details of a DMIS and DMIA for TNSPs are determined. There should also be sufficient time allowed for consultation with stakeholders to evaluate the differences between DNSPs and TNSPs, and any implications for the design and application of a scheme and mechanism. This would also allow us time to gather data and learn more from the DMIS and DMIA for DNSPs.

ENA stated the AER should be afforded enough time to develop and consult on the guidelines once the final rule is made. ENA agrees with the previous AER sentiment that DMIA should only be enabled at the start of the next regulatory control period.[132]

Given the need for the AER to develop and consult on the guidelines and to secure resources to fulfil this new function, the AER has indicated its preference to commence the rule change in the first quarter of 2021 in correspondence with the Commission. This would allow time for the DMIA to apply to the TransGrid, ElectraNet and Murraylink network revenue determinations.

The Commission sought stakeholder views on the requirement for the AER to develop and publish the DMIA by 31 March 2021. The South Australia Government supports this proposal.[133]

ENA notes AusNet Services and Powerlink are due to lodge their next regulatory proposals by 31 October 2020 and 31 January 2021, respectively, and therefore says transitional arrangements should be provided to allow the DMIA to be applied to these decisions.[134] ENA did not provide any references to the rules to evidence the need for transitional arrangements.

The Commission considers transitional arrangements are not required for the DMIA to apply to the upcoming AusNet Services and Powerlink revenue determinations. It is expected that these transmission businesses will highlight their intent to propose application of the DMIA in their initial revenue proposals to the AER, and then provide the formal requirements in their

128 AGL submission to AEMC draft determination, 24 October 2019, p. 2.

129 See here: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-transmission-ring-fencing-guideline-review

130 AER submission to AEMC Consultation paper, 11 July 2019, p. 2.

131 AER submission to AEMC Consultation paper, 11 July 2019, p. 3.

132 ENA submission to AEMC Consultation paper, 11 July 2019, p. 4.

133 Government of South Australia (Department of Energy and Mining) submission to AEMC draft determination, 14 October 2019, p. 1.

134 ENA submission to AEMC draft determination, 24 October 2019, p. 5.

revised revenue proposals. The Commission asked the AER and AusNet Services to comment on this issue.

The AER states:[135]

> ... we consider there may rationale for allowing some form of early adoption for only these TNSPs [AusNet and Powerlink]. However, our preliminary views are that this may not require a transitional rule. For example, we could allow these TNSPs to identify their interest in applying the DMIA in their regulatory proposals, and then provide the formal requirements in their revised proposals. This early adoption approach would mean that these TNSPs would not need to seek a re-opener to their existing determinations to apply the scheme".

AusNet Services confirmed it is satisfied that the transmission DMIA could apply to its next regulatory period without the need for a transitional rule.[136]

Commission's final determination to enable the DMIA for transmission

As detailed in section 2.1 of this final determination, the more preferable final rule introduces a DMIA mechanism to apply to transmission network service providers. The final rule requires:

- The AER must develop a demand management innovation allowance mechanism for transmission network service providers consistent with the demand management innovation allowance objective.[137]
- The objective of the demand management innovation allowance mechanism is to provide Transmission Network Service Providers with funding for research and development in demand management projects that have the potential to reduce long term network costs.[138]
- In developing and applying the mechanism, the AER must take into account the following:
  - the mechanism must be applied in a manner that contributes to the achievement of the demand management innovation allowance objective[139]
  - demand management projects should have the potential to manage ongoing changes in demand[140] and be innovative and not be otherwise efficient and prudent non-network options that a transmission network service provider should have provided for in its revenue proposal[141]

135 AER submission to AEMC draft determination, 15 November 2019, p. 2.

136 AusNet Services correspondence with the AEMC, 17 November 2019.

137 See clause 6A.7.6(a) of the Amending Rule.

138 See clause 6A.7.6(b) of the Amending Rule.

139 See clause 6A.7.6(c)(1) of the Amending Rule.

140 Again, this differs to the corresponding clause for distribution, which says 'demand management projects should have the potential to *deliver* ongoing *reductions in demand or peak demand*...' The broader reference to '*manage* ongoing *changes* in demand' better accommodates possible network projects to address issues arising from the growth of solar PV exports and falling minimum demand.

141 See clause 6A.7.6(c)(2) of the Amending Rule.

- the level of the allowance should be reasonable considering the long term benefit to retail customers, should only provide funding that is not available from any other source, and may vary by transmission network service provider and over time[142]
- the demand management innovation allowance may fund demand management projects which occur over a longer period than a regulatory control period.[143]

- Any demand management innovation allowance mechanism developed and applied by the AER must require transmission network service providers to publish reports on the nature and results of demand management projects that are the subject of the allowance.[144]
- The AER must develop and publish the demand management innovation allowance mechanism in accordance with the transmission consultation procedures by 31 March 2021.[145]
- There are also a number of amendments to existing clauses in chapter 6A of the NER to accommodate the demand management innovation allowance mechanism throughout the revenue determination process.[146]

142 See clause 6A.7.6(c)(3) of the Amending Rule.

143 See clause 6A.7.6(c)(4) of the Amending Rule.

144 See clause 6A.7.6(d) of the Amending Rule.

145 See clause 6A.7.6(e) and the transitional rule of the Amending Rule.

146 See amendments to clauses 6A.4.2, 6A.5.4, 6A.6.6, 6A.6.7, 6A.8.2, 6A.10.1A, 6A.14.1, 6A.17.1 and S6A.1.3 of the Amending Rule.

ABBREVIATIONS

AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
Capex	Capital expenditure
CESS	Capital efficiency sharing scheme
COAG	Council of Australian Governments
Commission	See AEMC
DMIA	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
EBSS	Efficiency benefit sharing scheme
ECA	Energy Consumers Australia
EEC	Energy Efficiency Council
ENA	Energy Networks Australia
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEO	National electricity objective
NER	National electricity rules
NPV	Net present value
Opex	Operating expenditure
PIAC	Public Interest Advocacy Group
R&D	Research and development
RIT-T	Regulatory investment test for transmission
STPIS	Service target performance incentive scheme
TNSP	Transmission network service provider
Totex	Total expenditure

A 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.

A.1 Final rule determination

In accordance with section 99 of the NEL the Commission has made this final rule determination in relation to the rule change request proposed by the ENA.

The Commission's reasons for making this final rule determination are set out in section 2.4 and in more detail in chapter 3 of this final rule determination.

A copy of the final rule, which is a more preferable rule, is published with this final rule determination. Its key features are described in section 2.1 of this final rule determination.

A.2 Power to make the rule

The Commission is satisfied that the more preferable final rule falls within the subject matter about which the Commission may make rules. The more preferable final rule falls within s. 34 of the NEL as it relates to regulating the operation of the national electricity market and regulating the activities of persons (including registered participants) participating in the national electricity market.[147]

In addition, the subject matter of the rule change request falls within section 34(2) of the NEL as it relates to matters specified in Schedule 1 to the NEL, being:

- The regulation of revenues earned or that may be earned by owners, controllers or operators of transmission systems from the provision by them of services that are the subject of a transmission determination.[148]
- 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 transmission determination.[149]

A.3 Additional rule making test – Northern Territory

The National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 provides the Commission with the ability to make a differential rule that varies in its terms between the national electricity system and the Northern Territory's local electricity system. The Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, it determines that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.

The Commission has considered whether a differential rule is required for the Northern Territory electricity service providers and concluded that it is not required in this instance.

147 Sections 34(1)(a)(i) and (iii) of the NEL.
148 Item 15 of Schedule 1 to the NEL.
149 Item 17 of Schedule 1 to the NEL.

This is because the Commission considers that the final rule will be able to operate in the Northern Territory without special arrangements. Therefore, the Commission has determined to make a uniform rule as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.

A.4 Revenue and pricing principles

In addition to having regard to the NEO, the Commission must take into account the revenue and pricing principles in making a rule with respect to (among other things) the regulation of revenue earned, or that may be earned, by transmission network service providers from provision of services that are the subject of a transmission determination.[150] The application of the revenue and pricing principles is discussed in section 2.2.3 of this determination.

A.5 More preferable rule

Under section 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule if the Commission is satisfied that, having regard to the issue or issues that were raised by the 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 NEO. As discussed in Chapter 2 of this determination, the Commission has determined to make a more preferable rule. The reasons for the Commission's decision are set out in section 2.4 of this determination.

A.6 Commission's considerations

In assessing the rule change requests the Commission considered:

- its powers under the NEL to make the rule
- the rule change request
- submissions received during first round consultation
- submissions received in response to the draft determination
- the ways in which the proposed rule will or is likely to contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[151]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of Australian Energy Market Operator (AEMO)'s declared network and system functions.[152] The final rule is compatible with AEMO's declared network and system functions because it is unrelated to them and therefore does not affect the performance of those functions.

150 Refer to section 88B and Items 15 to 24 of Schedule 1 to the NEL. The revenue and pricing principles are set out in section 7A of the NEL.

151 Under s. 33 of the NEL, the Commission must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the Commission'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.

152 Section 91(8) of the NEL.

A.7 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may, jointly with the AER, recommend to the COAG Energy Council that new or existing provisions of the NER be classified as civil penalty provisions.

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

A.8 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as conduct provisions.

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