RULE CHANGE

Australian Energy Market Commission

RULE DETERMINATION

National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012

Rule Proponent

Ministerial Council on Energy

11 October 2012

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

About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two principle functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

Summary

The Australian Energy Market Commission (AEMC or Commission) has made a final rule determination and final rule to establish a national framework for distribution network planning and expansion which would be applicable to distribution businesses in each national electricity market jurisdiction. This national framework consists of an annual planning and reporting process, including a number of demand side engagement obligations on distribution businesses, and a regulatory investment test for distribution (RIT-D) process.

The Commission considers that the final rule will contribute to the achievement of the National Electricity Objective (NEO) by establishing a clearly defined and efficient planning process for distribution network investment. This will support the efficient development of distribution networks. It will also provide transparency to, and information on, distribution business planning activities and decision making processes. This will assist market participants in making efficient investment decisions and enable non-network providers to put forward non-network options as credible alternatives to network investment.

In making its final rule determination, the Commission has considered whether the proposed framework will provide for the minimisation of total system costs which should, over time, lead to efficient prices. The Commission considers that the final rule will achieve this outcome.

The final rule has been made in response to a rule change request submitted by the Ministerial Council on Energy (MCE) on 30 March 2011.[1] The rule change request sought to implement (with some amendments) the recommendations put forward in the AEMC's Review of National Framework for Electricity Distribution Network Planning and Expansion which was completed in September 2009.

The Commission's final rule determination

The Commission's final rule determination is to make a more preferable rule which commences on 1 January 2013.[2] The final rule is largely reflective of, and consistent with, the rule proposed by the MCE. However, it incorporates several policy modifications and a number of amendments to improve and clarify the application and operation of the new national framework.

A brief summary of the key components of the national framework is provided below.

1 The MCE has since been amalgamated with the Ministerial Council on Mineral and Petroleum Resources to form the Standing Committee on Energy and Resources.

2 Schedule 5 of the final rule contains some changes to NER Chapters 6 and 6A that are consequential to the commencement of the RIT-D. These provisions will commence on 1 January 2014.

Distribution annual planning process

Each distribution network service provider (DNSP) will be required to carry out an annual planning review covering a minimum forward planning period of five years. The planning review will apply to all distribution assets and activities undertaken by DNSPs that would be expected to have a material impact on the distribution network.

Distribution annual planning report

Each DNSP will be required to publish a distribution annual planning report (DAPR) by the date specified by the relevant jurisdictional government. The DAPR will report on the outcomes of each DNSPs annual planning review. Specifically, the DAPR will include information on:

- forecasts, including capacity and load forecasts, at the sub-transmission and zone substation level and, where they have been identified, for primary distribution feeders;
- system limitations, which may include limitations resulting from forecast load exceeding total capacity, the need for asset refurbishment or the need to improve network reliability;
- projects that have been, or will be, assessed under the regulatory investment test for distribution (RIT-D);
- other committed projects which are urgent and unforseen, or replacement and refurbishment projects, and which have a capital cost of $2 million or greater; and
- other high level summary information, to provide important context to DNSPs' planning processes and activities.[3]

Demand side engagement obligations

Each DNSP will be required to develop a demand side engagement strategy. The strategy, which is to be documented and published, will detail a DNSP's processes and procedures for assessing non-network options as alternatives to network expenditure and interacting with non-network providers. DNSPs will also be required to establish and maintain a register of parties interested in being notified of developments relating to distribution network planning and expansion.

The final rule is one part of the AEMC's broader work program to encourage more timely and meaningful engagement between network business, and consumers and other stakeholders. In addition to the new annual reporting and demand side

3 This additional information includes: a description of the network, outcomes from joint planning undertaken with other network service providers, performance standards and compliance against these standards, activities and actions taken to promote non-network initiatives (including embedded generation), information on any significant investments in metering services and a regional development plan.

engagement obligations on distribution businesses, our other work to enhance engagement includes:

- the power of choice review, which includes reforms designed to provide consumers with the information, education, incentives and technology they need to efficiently manage their electricity use through greater demand side participation; and
- the network regulation rule changes, which include proposals to encourage more timely and meaningful consumer engagement as part of the regulatory determination process.

Joint planning arrangements

DNSPs will be required to undertake joint planning with the owners of any connected networks where there are issues affecting multiple networks. The relevant network service providers will also be required to carry out the requirements of the existing regulatory investment test for transmission (RIT-T) for projects identified under the joint planning process. The final rule also provides some flexibility for the RIT-D to be carried out for joint planning projects where none of the potential options to address the network issue include a transmission component with an estimated capital cost greater than the RIT-T cost threshold level (currently $5 million)..

Regulatory investment test for distribution

The RIT-D, which will replace the current regulatory test, establishes the processes and criteria to be applied by DNSPs in order to identify investment options which best address the needs of the network. The RIT-D will be applicable in circumstances where a network problem exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $5 million. Certain types of projects and expenditure will be exempt from assessment under the RIT-D, including projects initiated to address urgent and unforeseen network issues and projects related to the replacement and refurbishment of existing assets.

The RIT-D rules set out the principles to which the test, when being developed by the Australian Energy Regulator (AER), must adhere. The RIT-D rules also include the procedural consultation requirements to be followed by DNSPs when applying the test.[4] In summary, the RIT-D will require DNSPs to assess the costs and, where appropriate, the benefits of each credible investment option to address a specific network problem to identify the option which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

Dispute resolution process

The final rule includes a dispute resolution process that would be open to all projects subject to the RIT-D. Relevant parties would be able to raise disputes with the AER in relation to the conclusions made by the RIT-D proponent in a final project assessment

4 See Figure 9.1 for an illustrative summary of the RIT-D process.

report. The AER may then either reject a dispute, or make a determination on the dispute (the timeframes for doing so will depend on the complexity of the dispute). The AER may only make a determination which directs a DNSP to amend its final project assessment report where the DNSP has not correctly applied the RIT-D in accordance with the rules, or where the DNSP has made a manifest error in its calculations.[5]

Implementation and transition

It is intended that the existing jurisdictional arrangements for annual planning, annual reporting and project assessment will be rolled back to the extent that they are covered by the final rule. To allow sufficient time for this transition, the Commission has identified 1 January 2013 as the date for commencement of the rule.

In recognition that implementation of the final rule will result in changes to DNSPs' and other market participants' operational practices, it includes the following key transitional arrangements:[6]

- DNSPs have been provided with a minimum period of six months after the rule commences before being required to publish their first DAPR;
- DNSPs have been provided with a maximum period of nine months after the rule commences within which to publish their first demand side engagement document and establish the demand side engagement register;
- the AER has been provided with a period of nine months after the rule commences to develop and publish the RIT-D and RIT-D application guidelines; and
- DNSPs (and transmission network services providers, where relevant) have been provided with a period of 12 months after the rule commences before having to apply the RIT-D.

Reasons for the Commission's final rule determination

The Commission is satisfied that the final rule will, or is likely to, contribute to the achievement of the NEO. Moreover, it is satisfied that the final rule is likely to better contribute to the achievement of the NEO than the proposed rule. The Commission considers that the final rule promotes efficient outcomes by:

- creating incentives for, and a framework within which, DNSPs can explore non-network options as alternatives to capital expenditure and for non-network providers to efficiently plan and offer alternative, more cost effective options to network augmentations thereby promoting efficient investment in distribution networks;

5 See Figure 10.1 for an illustrative summary of the dispute resolution process.

6 See Figure 11.1 for a summary of the implementation and transition timeframes.

- establishing a clearly defined and efficient planning process which facilitates the timely identification and resolution by DNSPs of potential problems on their networks thereby promoting efficient operation of, and investment in, distribution networks; and

- providing greater transparency to, and information on, DNSP planning activities to assist network users to plan where best to connect to the network thereby promoting efficient use of electricity services.

Contents

1 MCE's rule change request

1.1 The rule change request

On 30 March 2011, the Ministerial Council on Energy (MCE) (proponent)[7] submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) to introduce a new national framework for electricity distribution network planning and expansion (rule change request) which would be applicable to distribution businesses in each National Electricity Market (NEM) jurisdiction.[8]

The rule change request seeks to implement the rule change recommendations made by the AEMC in its final report for the Review of National Framework for Electricity Distribution Network Planning and Expansion (the Review) (Final Report).[9] The MCE's rule change request included several modifications to the recommendations set out in the Final Report.

1.2 Rationale for the rule change request

The current regulatory arrangements governing distribution network planning are contained in Chapter 5 of the National Electricity Rules (NER) and also in various jurisdictional instruments. These two regimes do not operate in a complementary way and, as a result, the obligations of distribution network service providers (DNSPs) for network planning are unclear. In addition, the jurisdictional arrangements differ significantly in both their objectives and application.

There is a view that the lack of consistency and transparency associated with the current arrangements impedes efficient investment by both network service providers (NSPs) and market participants and creates a bias against the consideration of non-network options. The objective of this rule change request is to implement a national framework for distribution network planning and expansion which addresses these issues.

1.3 Solution proposed in the rule change request

The MCE's rule change request concluded a significant and extensive policy development phase, as outlined in section 1.4 below. The proposed rule sets out a national framework for distribution network planning and expansion that includes:

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7 The MCE now forms part of the Standing Council on Energy and Resources or SCER.

8 Throughout this final rule determination, reference to 'national framework' means the national rules proposed to replace the separate rules that have to date operated in each jurisdiction and which would be applicable to distribution businesses in each NEM jurisdiction.

9 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney.

- a distribution annual planning review;
- a distribution annual planning report (DAPR);
- a demand side engagement strategy;
- joint planning arrangements;
- the regulatory investment test for distribution (RIT-D); and
- a dispute resolution process.

The key elements of the proposed rule are described further in Chapters 5-11.

1.4 Relevant background

The 2006 amended Australian Energy Market Agreement (AEMA) set out a number of energy market regulatory functions currently carried out by jurisdictions that the Council of Australian Governments (COAG) agreed would be transferred to a national framework.[10] In respect of electricity distribution, these included connections and capital contribution requirements, distribution network expansion and distributor interface with customers and embedded generators.

In 2007, the MCE Standing Committee of Officials (MCE SCO) commissioned a report by NERA Economic Consulting (NERA) and Allen Consulting Group (ACG) to provide advice on a national framework for electricity distribution network planning, connections and capital contribution arrangements. The NERA and ACG Report, *Network Planning and Connection Arrangements – National Framework for Distribution Networks*, was published in August 2007.[11]

In its December 2008 policy response to the NERA and ACG Report, the MCE indicated that a national framework for electricity distribution connection arrangements, and electricity distribution connection charge and capital contribution arrangements, would be progressed as part of the same legislative package as the National Energy Customer Framework (NECF).[12]

In respect of a national framework for distribution planning and expansion, the MCE considered that, given a number of recent developments in the NEM,[13] further

10 See Annexure 2 of the AEMA for a summary of the relevant retail and distribution functions which governments agreed would be transferred to a national framework.

11 This report is available at www.mce.gov.au.

12 NECF refers to a national arrangement designed to govern the sale and supply of electricity and natural gas to retail customers. On 1 July 2012, the jurisdictions of Tasmania, the Australian Capital Territory and the Commonwealth became the first jurisdictions to implement the national arrangement. New South Wales intends to implement the framework on 1 July 2013. Other jurisdictions are expected to follow in accordance with their own implementation plans.

13 Namely the development of a regulatory investment test for transmission (RIT-T), the proposed introduction of a Carbon Pollution Reduction Scheme (CPRS) and increased Renewable Energy Target (RET), and the AEMC's review of Demand Side Participation in the NEM.

consultation and analysis was required before details of arrangements governing planning and expansion of electricity distribution networks could be finalised. In light of the AEMC having recently completed a similar review of transmission arrangements, the MCE considered it was appropriate for the AEMC to progress this work.[14]

In December 2008, the MCE directed the AEMC to conduct a review into the arrangements for electricity distribution planning and expansion in the NEM and propose recommendations to assist the establishment of a national framework for such planning and expansion.[15]

The AEMC submitted its Final Report to the MCE on 23 September 2009.[16] The Final Report provided the AEMC's recommendations and supporting reasoning for the establishment of a national framework. It also included a proposed rule to implement the new arrangements for consideration by the MCE.

The AEMC's recommended design for a national distribution planning framework consisted of three key components:

- an annual planning and reporting process;
- a demand side engagement strategy; and
- the RIT-D process.

The AEMC considered that it was through the interaction of these three components that the intended purpose and objectives of the national framework would best be achieved.

In September 2010, the MCE provided its response to the recommendations set out in the Final Report.[17] Overall, the MCE expressed support for the AEMC’s findings and recommendations.

Subsequently, on 30 March 2011, the MCE lodged a rule change request, including a proposed rule, to the AEMC. The MCE requested that the AEMC progress the rule change request having regard to the contents of the MCE’s response.

1.5 Commencement of rule making process

On 30 September 2011, the Commission published a notice under s. 95 of the National Electricity Law (NEL) advising of its intention to commence the rule making process

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14 AEMC 2008, *National Transmission Planning Arrangements*, Final Report to MCE, 30 June 2008, Sydney

15 The terms of reference for the review is available at www.aemc.gov.au.

16 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. vii.

17 MCE 2010, *Review of National Framework for Electricity Distribution Network Planning and Expansion: Response to the Australian Energy Market Commission’s Final Report*, September 2010.

and the first round of consultation in respect of the rule change request. A consultation paper prepared by AEMC staff identifying specific issues and questions for consultation was also published with the rule change request.[18] Submissions closed on 24 November 2011.

The Commission received 16 submissions and three supplementary submissions on the rule change request as part of the first round of consultation. These submissions are available on the AEMC website. Summaries of the policy and drafting issues raised, and the Commission's response to each issue, are contained in Appendices A and B of the draft rule determination for this rule change request.

1.6 Publication of draft rule determination and draft rule

On 14 June 2012, the Commission published a notice under s. 99 of the NEL and a draft rule determination in relation to the rule change request (draft rule determination). The draft rule determination included a draft rule.

Submissions on the draft rule determination closed on 9 August 2012. The Commission received nine submissions on the draft rule determination. These are available on the AEMC website. Summaries of the policy and drafting issues raised in submissions, and the Commission's response to each issue, are contained in Appendices A and B of this final rule determination.

1.7 Extensions of time

The timing for publication of the draft rule determination was extended under s. 107 of the NEL on four occasions. On 30 September 2011, the Commission published a notice under s. 107 of the NEL extending the time period for publishing the draft rule determination to 22 March 2012. On 9 February 2012, a further notice was published extending the time period to 26 April 2012. On both occasions, the Commission considered that the rule change request raised issues of sufficient complexity and difficulty such that additional time was necessary.

On 5 April 2012, the Commission published a third notice extending the time period to 14 June 2012. In this instance, consultation with stakeholders resulted in a number of supplementary submissions to the consultation paper. These supplementary submissions included a number of alternative solutions to address several of the key issues identified. To ensure these submissions were given due consideration, the Commission extended the period of time for making the draft rule determination until mid-June.

On 13 September 2012, the Commission published a fourth notice extending the time period for publishing the final rule determination to 11 October 2012. The Commission considered that additional time was necessary to ensure that the issues raised by

18 AEMC 2011, *Distribution Network Planning and Expansion Framework*, Consultation Paper, 29 September 2011, Sydney.

stakeholders in their submissions to the draft rule determination could be given full and detailed consideration ahead of finalising the rule and publishing the final rule determination.

1.8 AEMC reviews and rule changes

The AEMC is currently undertaking a number of other review and rule change processes which may be of interest to stakeholders engaged with this rule change request. These are:

- EPR0031: Review of Distribution Reliability Outcomes and Standards - National Workstream.
- EPR0022: Power of Choice Review.
- EPR0019: Transmission Frameworks Review.
- ERC0134: Economic Regulation of Network Service Providers (proposed by the Australian Energy Regulator (AER) and Energy Users Rule Change Committee (EURCC)).
- ERC0147: Connecting Embedded Generators (proposed by ClimateWorks Australia, Seed Advisory and the Property Council of Australia).
- ERC0142: Distribution Losses in Expenditure Forecasts (proposed by the Copper Development Centre (CDC)).

Further information on the AEMC’s reviews and rule changes can be found on the AEMC website.

2 Final rule determination

2.1 Commission's determination

In accordance with s. 102 of the NEL, the Commission has made this final rule determination in relation to the rule proposed by the MCE. In accordance with s. 103 of the NEL, the Commission has determined not to make the proposed rule but rather to make a more preferable rule.[19] The final rule largely adopts the MCE's proposed rule, subject to several policy modifications and amendments to improve the clarity and application of the rule.

The Commission's reasons for making this final rule determination are set out in section 2.4.

The *National Electricity Amendment (Distribution Network Planning and Expansion Framework) rule 2012 No 5* (final rule) is published with this final rule determination. The final rule commences on 1 January 2013.[20] The key features of each element of the final rule are described in Chapters 5 to 11 of this document.

2.2 Commission's considerations

In assessing the rule change request, the Commission has considered:

- its powers under the NEL to make the rule;
- the rule change request;
- the MCE's policy response to the AEMC's Final Report;
- submissions and supplementary submissions received during the first round of consultation;
- submissions received during the second round of consultation; and
- the ways in which the proposed rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).

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

20 Schedule 5 of the final rule contains some changes to NER Chapters 6 and 6A that are consequential to the commencement of the RIT-D. These provisions will commence on 1 January 2014.

2.3 Commission's power to make the rule

The Commission is satisfied that the final rule falls within the subject matter about which the Commission may make rules as set out in s. 34 of the NEL and in Schedule 1 of the NEL. The final rule is within:

- the matter set out in s. 34 (1)(a)(iii), as it relates to the activities of persons participating in the NEM or involved in the operation of the national electricity system; and
- the matters set out in items 11, 12 of Schedule 1 to the NEL, as it relates to the operation of transmission and distribution systems which is subject to the NER.

2.4 Rule making test

Under s. 88(1) of 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 NEO. This is the decision making framework that the Commission must apply.

In applying the rule making test in s. 88 of the NEL, the Commission has also considered whether there are any relevant MCE statements of policy principles as required under s. 33 of the NEL. The MCE has not issued a statement of policy principles for this rule change request.

The NEO is set out in s. 7 of the NEL as follows:

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

For this rule change request, the Commission considers that the relevant aspects of the NEO are:[21]

- efficient investment in distribution networks;
- efficient operation of distribution networks; and
- efficient use of electricity services.

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21 Under s. 88(2) of the NEL, for the purposes of s. 88(1) the AEMC may give such weight to any aspect of the NEO as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles.

The Commission is satisfied that the final rule will, or is likely to, contribute to the achievement of the NEO by providing clearly defined, nationally consistent arrangements which will promote more efficient outcomes than under current arrangements. This will promote the long term interests of consumers in respect of the price of electricity. The final rule promotes efficiency in the following ways:

- by creating incentives for, and a framework within which, DNSPs can explore non-network options as alternatives to capital expenditure and for non-network providers to efficiently plan and offer alternative, more cost effective options to network augmentations thereby promoting efficient investment in distribution networks;
- by establishing a clearly defined and efficient planning process which facilitates the timely identification and resolution by DNSPs of potential problems on their networks thereby promoting efficient operation of, and investment in, distribution networks; and
- providing greater transparency to, and information on, DNSP planning activities to assist network users in planning where best to connect to the network thereby promoting efficient use of electricity services.

Under s. 91(8) of the NEL, 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 functions. The final rule is compatible with AEMO’s declared network functions because it clarifies the arrangements in respect of joint planning and therefore enhances AEMO's ability to perform its declared network functions.

2.5 More preferable rule

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

Having regard to the issues raised by the proposed rule, the Commission is satisfied that the final rule will, or is likely to, better contribute to the achievement of the NEO than the proposed rule for the following reasons:

- The final rule achieves a better balance between the regulatory burden on DNSPs in complying with the new national framework and the potential benefits to be gained from planning under a national regime, relative to the proposed rule. It does so by removing several obligations proposed to be imposed on DNSPs where the benefits of complying with the obligation would be unlikely to outweigh the costs of doing so.

- The final rule creates a more efficient planning process relative to the proposed rule by removing (or amending) several of the proposed obligations on the AER where the intended purpose of the obligation is already (or could be better) achieved by other, more efficient means.

- The final rule should improve the application and operation of the national framework by making a number of amendments to the drafting of the proposed rule to remove any ambiguity and improve the clarity of the rule.

3 Commission's reasons

The Commission has analysed the rule change request and assessed the issues that it raises. For the reasons set out below and in the following chapters, the Commission has determined that a rule should be made.

3.1 Assessment of issues

A key assumption in assessing this rule change request was that the existence of different regulatory arrangements (that are not justified by differences in local circumstances) for electricity distribution network planning and expansion constitutes an impediment to the development of a truly national energy market. This was likely to result in potentially significant costs being imposed on market participants, with those costs typically being passed on to end users.

The Commission considers that streamlining and improving the quality of the distribution planning frameworks can be expected to lower the cost and complexity of regulation. This would be particularly relevant to investors and market participants seeking to operate across jurisdictions. In addition, a national approach could enhance regulatory certainty and lower barriers to competition.

Further, and consistent with the conclusions of the AEMC's Review, the Commission considers that the existence of a robust planning and expansion framework for monopoly distribution networks is likely to facilitate sound and transparent decision making.

Given the objectives of the AEMA and the conclusions of the AEMC's Review, this rule change request represents the next stage in the development and implementation of a national framework for electricity distribution network planning and expansion.

In this context, the Commission has not assessed whether or not a national planning framework is needed. Rather, it has assessed whether the proposed design of the national framework as proposed in the rule change request is appropriate and will, or is likely to, contribute to the achievement of the NEO.

3.2 Assessment of rule

The Commission's final rule largely adopts the MCE's proposed rule, subject to several policy modifications and amendments to improve the clarity and application of the rule.

These policy modifications and amendments are set out in detail with supporting reasoning in Chapters 5 to 11 of this document. In summary, the key amendments made to the proposed rule include:

- removal of the requirement for DNSPs to conduct a public forum on the content of the DAPR;

- removal of the requirement for DAPRs to be certified by the Chief Executive Officer (CEO), and a director or company secretary of the DNSP;
- removal of the ability for the AER to grant exemptions or variations to the annual reporting requirements;
- removal of the requirement for DNSPs to establish, maintain and publish a database of non-network proposals and/or case studies of non-network proposals as part of the proposed demand side engagement strategy;
- amendments to the arrangements for the assessment of projects identified through joint planning by DNSPs and TNSPs;
- amendments to the proposed specification threshold test (STT);
- amendments to the proposed project specification report (renamed the non-network options report);
- clarification in relation to the reapplication of the RIT-D in certain circumstances;
- removal of specific review and audit powers for the AER in relation to DNSPs' consideration of non-network options;
- removal of the ability for the AER to grant exemptions from the dispute resolution process; and
- clarification in relation to the transition from the regulatory test to the RIT-D.

3.3 Changes to the structure of Chapter 5 of the NER

In addition to the changes noted above, the final rule includes changes to the broader structure of NER Chapter 5 in order to more clearly distinguish between the connection arrangements (now in Chapter 5 Part A) and the planning arrangements (now in Chapter 5 Part B).[22] These changes are structural only and do not affect the rationale of, nor the intent behind, any rules not directly related to, or affected by, this rule change request.

The Commission considers that separation of the connection and planning arrangements currently set out in NER Chapter 5 into clearly defined sections will simplify the rules and improve their accessibility to, and usability by, market participants and interested parties.

In addition, a discrete section of the rules for connections may help to facilitate any later review of the connection arrangements which may be proposed as an outcome of

22 In their submissions to the draft rule determination, Aurora Energy and the Clean Energy Council noted their support for the proposed structural changes to Chapter 5 of the NER to provide clear distinction between connection arrangements and the planning arrangements. See Aurora Energy, Draft Rule Determination submission, p. 1; Clean Energy Council, Draft Rule Determination submission, p. 2.

the Transmission Frameworks Review (TFR), without the need to unsettle the new distribution planning rules.[23]

Table 3.1 sets out the key sections of Chapter 5 Part B as restructured by the final rule, including references to the equivalent sections in the current rules.

Table 3.1 Structure of new Part B Network Planning and Expansion

Final rule reference	Content of clause	Current NER reference
clause 5.10.2	Sets out local definitions used in Part B	n/a
clause 5.11.1	Sets out obligations regarding forecasts for connection points to the transmission network	clause 5.6.1
clause 5.11.2	Sets out obligations of NSPs relating to the identification of network limitations	clause 5.6.2
clause 5.12	Sets out planning and reporting obligations for TNSPs	clause 5.6.2A
clause 5.13	Sets out planning and reporting obligations for DNSPs	n/a
clause 5.14	Sets out joint planning obligations of NSPs	clause 5.6.2
clause 5.15	Relates to regulatory investment tests generally	clauses 5.6.5D, 5.6.5E
clause 5.16	Relates to the regulatory investment test for transmission	clauses 5.6.5B, 5.6.5C, 5.6.6, 5.6.6A, 5.6.6AA
clause 5.17	Relates to the regulatory investment test for distribution	n/a
clause 5.18	Relates to the construction of funded augmentations	clause 5.6.6B
clause 5.19	Relates to Scale Efficient Network Extensions	clause 5.5A
clause 5.20	Relates to AEMO's national transmission planning responsibilities	clause 5.6A
clause 5.21	Sets out AEMO's obligations to publish information and guidelines, and provide advice on network development	clause 5.6.3
clause 5.22	Relates to the AEMC's last resort planning powers	clause 5.6.4

23 In chapter 12 of the TFR First Interim Report, the Commission indicated that amendments to the NER Chapter 5 connection arrangements are required to clarify their interpretation and application. It noted that this clarification should proceed regardless of whether some of the more significant potential reforms relevant to connections discussed in chapters 13 and 14 of that report are progressed. For further information see: AEMC 2011, *Transmission Frameworks Review, First Interim Report*, 17 November 2011, Sydney, pp. 155-169.

3.4 AEMC review of the national framework

The proposed rule included a requirement for the AEMC to conduct a review of the national framework three years after the date the rule commenced.[24] It was intended that this review would assess the effectiveness of the provisions and identify any potential areas for further improvement.

The Commission has decided not to include this requirement in the final rule on the basis that there are already established processes under which such a review can be undertaken by the AEMC if required.[25] The existing provisions under the NEL allow for flexibility in the nature and content of any such review if undertaken. The Commission therefore does not consider it appropriate to limit this flexibility by including a rule in the NER requiring the AEMC to undertake a review of the national framework within a specified timeframe.

3.5 Civil penalty provisions

The provisions of the NER which are classified as civil penalty provisions are listed in the National Electricity (South Australia) Regulations. The Commission may amend or remove these provisions but must notify SCER of the policy rationale for taking this course of action.

The final rule omits a number of provisions which are currently classified as civil penalty provisions. In addition, the final rule amends and changes the clause references of certain provisions which are currently classified as civil penalty provisions. The current civil penalty provisions which are amended or removed are set out in Table 3.2.

While the Commission cannot create new civil penalty provisions, it may recommend to SCER that new or existing provisions of the NER be classified as a civil penalty provisions. The new provisions which the Commission is proposing to recommend to SCER be classified as civil penalty provisions are set out in Table 3.3.

The Commission considers that the new and amended provisions should be classified as civil penalty provisions because breach of these provisions could lead to investment decisions being made without using good quality planning information. If this was to occur, this could pose a risk to the secure operation of the NEM. In addition, the classification of these provisions as civil penalty provisions would encourage compliance by relevant parties with these provisions.[26]

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24 Proposed clause 5.6.2AA(b).

25 See s. 41 of the NEL which provides for the MCE to direct the AEMC to review any matter relating to a market for electricity. Also see s. 45 of the NEL which provides for the AEMC to conduct a review into the operation and effectiveness of the rules or any matter relating to the rules.

26 These provisions would only become civil penalty provisions if the relevant amendments to the National Electricity (South Australia) Regulations were made and come into effect.

In its submission to the consultation paper, the AER noted that a major challenge currently presented to it in monitoring and enforcing compliance with the current network planning provisions is the lack of enforcement tools available to it.[27] The AER considered that the effectiveness of the network planning framework may be further improved if certain obligations, in particular those in respect of the RIT-T and the RIT-D, were classified as civil penalty provisions.

In the draft rule determination, the Commission noted that it did not propose to recommend to SCER that any of the provisions related to the RIT-T or the RIT-D be classified as civil penalty provisions under the National Electricity (South Australia) Regulations. While classification of these provisions as civil penalty provisions may encourage compliance with these provisions, the Commission did not consider that a breach of these rules would pose a direct risk to the secure operation of the NEM.

In submissions to the draft rule determination, several DNSPs noted that they supported the AEMC's position in respect of not classifying any provisions related to the RIT-T and RIT-D as civil penalty provisions.[28]

Having regard to these submissions, the Commission maintains its view set out in the draft rule determination on this matter.

27 Specifically, the AER noted that none of the requirements regarding the need to undertake a regulatory investment test for transmission (RIT-T) and the associated consultation requirements were listed as civil penalty provisions under the National Electricity (South Australia) Regulations. The implication of this is that the only formal action the AER could take in relation to a suspected breach of these provisions would be to seek an order from the Federal Court. See AER, Consultation Paper submission, pp. 7-8.

28 Aurora Energy, Draft Rule Determination submission, p. 3; Ergon Energy, Draft Rule Determination submission, p. 9; Victorian DNSPs, Draft Rule Determination submission, p. 17; Energex, Draft Rule Determination submission, p. 23.

Table 3.2 Existing civil penalty provisions affected by the final rule

Current clause reference	New clause reference	Recommendation to SCER	Reason for recommendation
clause 5.6.2(a)	New clause 5.12.1(a)	Retain as civil penalty provision	Restructured and renumbered with minor amendments: original clause split into two separate clauses.
	New clause 5.13.1(a)(2)		
clause 5.6.2(b)	New clause 5.12.1(b)	Retain as civil penalty provision	Renumbered with minor amendments: reference to DNSPs removed. Clause remains consistent with original intent.
clause 5.6.2(c)	New clause 5.14.1(d)(4)(I)	Retain as civil penalty provision	Restructured and renumbered with minor amendments: reference to demand side engagement register included.
	New clause 5.14.1(b)		
clause 5.6.2(e)	New clause 5.11.2(a)	Retain as civil penalty provisions	Restructured and renumbered with minor amendments: original clause split into three separate clauses with minor changes made to the terminology used to accommodate new definitions. Clause remains consistent with original intent.
	New clause 5.11.2(b)		
	New clause 5.11.2(c)		
clause 5.6.2(e1)	n/a	Remove	Clause omitted in final rule.
clause 5.6.2(e2)	n/a	Remove	Clause omitted in final rule.
clause 5.6.2(f)	n/a	Remove	Clause omitted in final rule.
clause 5.6.2(g)	n/a	Remove	Clause omitted in final rule.
clause 5.6.2(g1)	n/a	Remove	Clause omitted in final rule.
clause 5.6.2(h)	n/a	Remove	Clause omitted in final rule.

clause 5.6.2(k)	n/a	Remove	Clause omitted in final rule.
clause 5.6.2(m)	New clause 5.4AA(b)	Retain as civil penalty provision	Renumbered (with no amendments).
clause 5.6.2(n)	New clause 5.2.6	Retain as civil penalty provision	Renumbered (with no amendments).
clause 5.6.4(l)	New clause 5.22(k)	Retain as civil penalty provision	Renumbered (with no amendments).

Table 3.3 Recommended new civil penalty provisions

Proposed clause reference	New clause reference	Recommendation to SCER	Reason for recommendation
Proposed clause 5.6.2(b1)	New clause 5.14.1(a)(2)	Classify as new civil penalty provision	Obligation on TNSPs to conduct joint planning with DNSPs. Equivalent clause to new clause 5.14.1(a)(1) which is also recommended as a civil penalty provision.
Proposed clause 5.6.2AA(g)	New clause 5.13.1(d)	Classify as new civil penalty provision	Obligations on DNSPs in conducting the distribution annual planning review.
Proposed clause 5.6.2AA(h)	New clause 5.14.1(a)(1)	Classify as new civil penalty provisions	Obligation on DNSPs to conduct joint planning with TNSPs. Equivalent clause to new clause 5.14.1(a)(2) which is also recommended as a civil penalty provision.
	New clause 5.14.1(d)	Classify as new civil penalty provisions	Obligations on DNSPs and TNSPs in conducting joint planning.

4 Commission's assessment approach

This chapter describes the Commission's approach to assessing the rule change request in accordance with the requirements set out in the NEL (and explained in Chapter 2).

In assessing the proposed rule, draft rule and the final rule, the Commission has given particular consideration to the likely impacts of these rules on the following aspects of the NEO:

- efficient investment in distribution networks, including incentives for DNSPs to explore non-network options as alternatives to capital expenditure and for non-network providers to efficiently plan and offer alternative, more cost effective options to network augmentations;
- efficient operation of networks, for example, by establishing a clearly defined and efficient planning process to allow DNSPs to identify and address potential problems on the network in a timely manner; and
- efficient use of electricity services, for example, by providing greater transparency to, and information on, DNSP planning activities to assist network users in planning where best to connect to the network.

To assist in its assessment, the Commission has also considered each element of the national framework set out in the proposed rule, draft rule and final rule against the following criteria:

- transparency - whether DNSPs would be required to make available sufficient information to enable network users to make efficient decisions, and non-network providers to propose feasible and credible alternatives to address network problems;
- proportionality – whether the costs arising from the proposed processes and regulatory requirements were proportionate to the benefits. The extent of information provided and the consultation processes must strike the appropriate balance; and
- harmonisation of jurisdictional requirements – whether the frameworks would provide for differences in operating environments and network conditions across DNSPs, while recognising that maintaining consistency across the NEM was a key objective of the rule change request.

Economically efficient outcomes will be achieved where the frameworks in the NER provide for the minimisation of total system costs. This should, over time, lead to efficient prices and higher quality and service for consumers. In assessing the proposed rule, draft rule and the final rule, the Commission has therefore also considered the extent to which these rules would avoid creating bias towards any particular technology, including towards network solutions where non-network options are available.

The effects of the proposed rule, draft rule and the final rule on these criteria have been compared with the status quo. In this case, the status quo included existing jurisdictional arrangements as well as the provisions currently contained in Chapter 5 of the NER.

5 Distribution annual planning review

This chapter sets out the Commission's views in relation to the distribution annual planning review, having regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 5.1 describes the proposed distribution annual planning review and summarises stakeholder responses to the first round of consultation on this matter;
- section 5.2 describes the distribution annual planning review set out in the draft rule and summarises stakeholder responses to the second round of consultation on this matter;
- section 5.3 sets out the differences between the draft rule and the final rule;
- section 5.4 sets out the Commission's assessment of the final rule in respect of the distribution annual planning review; and
- based on the Commission's assessment in section 5.4, section 5.5 sets out the Commission's conclusions on this matter.

5.1 Proposed rule

5.1.1 Description of the proposed rule

The proposed rule for the distribution annual planning review consists of a number of key elements as follows:

- Each DNSP would be required to undertake an annual planning process covering a minimum forward planning period of five years for its distribution assets (and ten years for dual function assets[29]).
- The forward planning period would commence one day after the 'jurisdiction specified date'.[30]
- The planning process would apply to all distribution network assets and activities undertaken by DNSPs that would be expected to have a material impact on the distribution network in the forward planning period.
- In carrying out the planning process, DNSPs would, at a minimum, be required to:

29 The NER defines dual function assets as any part of a network owned, operated or controlled by a DNSP which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network.

30 This date would be the date prescribed by regulation under the application Act of a participating jurisdiction.

- prepare forecasts of maximum demands for the relevant network assets;
- identify (based on those forecasts) system limitations; and
- take into account non-network options when considering investment options.

Included within the proposed arrangements for the distribution annual planning review are discrete proposals for a distribution annual planning report, a demand side engagement strategy and joint planning. These components are dealt with separately in Chapters 6, 7 and 8, respectively.

Current arrangements

Currently, the NER contains a high level obligation on DNSPs to analyse the expected future operation of the distribution network over a minimum five year period.[31] This obligation, although applicable to all NEM jurisdictions, is vague and in most cases is supplemented by jurisdictional arrangements which differ in respect of rigour and transparency.[32] The proponent intended that the proposed rule would replace these current arrangements and streamline the obligations into a single national framework.

5.1.2 Proponent's view

In the rule change request, the proponent states that the purpose of having a national annual planning process is to ensure that all DNSPs conduct a clearly defined, common and efficient planning process. Such a process would assist in maintaining a secure, reliable and safe supply of electricity for end users across the NEM. Further, the proponent considers that having clearly defined planning obligations would assist transmission network service providers (TNSPs), connection applicants and non-network providers to understand DNSPs' decision making processes and make more efficient investment decisions when participating in the NEM.

5.1.3 Stakeholder views - first round of consultation

In submissions to the consultation paper, stakeholders were generally supportive of the proposed arrangements for the distribution annual planning review.

Start of the forward planning period

In response to a question posed in the consultation paper regarding the forward planning period, the majority of DNSPs supported the proposal to allow each

31 NER clause 5.6.2(a).

32 For a comparison of jurisdictional planning and reporting requirements (as at July 2009) see: AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Draft Report, 7 July 2009, Sydney, Appendix D.

jurisdiction to determine the start date of the forward planning period.[33] The Energy Networks Association (ENA) and Victorian DNSPs[34] considered that aligning planning periods nationally would reduce the usefulness and relevance of the published information and would not facilitate transparency.[35]

In contrast, the AER and EnerNOC expressed support for the implementation of a uniform start date for the forward planning period and publication of the DAPRs.[36] The AER considered this would improve transparency and consistency in industry practices and more effectively facilitate joint planning across jurisdictions and between transmission and distribution networks. In addition, EnerNOC considered a single start date would be beneficial given the possibility of projects that cover more than one jurisdiction.

Stakeholders were divided in their views on whether it was necessary to include a default start date for the forward planning period in the rules.[37] Ergon Energy considered that any default date should be subject to jurisdictional transitional arrangements to ensure DNSPs would not be unfairly subject to complying with both jurisdictional and new national reporting requirements.[38]

Treatment of dual function assets

Ausgrid and Endeavour Energy sought clarity on the treatment of dual function assets within the proposed annual planning arrangements.[39]

Ausgrid considered that the proposed national framework would create a number of anomalies in relation to the obligations of NSPs who are registered as a DNSP for their distribution assets and as a TNSP for their dual function assets.[40] It noted that the proposed rule would result in a DNSP who also owns and operates dual function assets (as a TNSP) being required to:

- conduct an annual planning review for its dual function assets as a TNSP rather than an integrated review of all assets, and consult with itself as a DNSP;

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33 ENA, Consultation Paper submission, p. 5; Ergon Energy, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 1; Victorian DNSPs, Consultation Paper submission, p. 2; Aurora Energy, Consultation Paper submission, p. 2; Ausgrid, Consultation Paper submission, p. 3; Endeavour Energy, Consultation Paper submission, p. 1; ETSA Utilities, Consultation Paper submission, p. 4; Essential Energy, Consultation Paper submission, p. 4; Origin, Consultation Paper submission, p. 1.

34 The Victorian distribution businesses are CitiPower and Powercor Australia, United Energy, SP AusNet and Jemena Electricity Networks.

35 ENA, Consultation Paper submission, p.5; Victorian DNSPs, Consultation Paper submission, p. 2.

36 AER, Consultation Paper submission, p. 2; EnerNOC, Consultation Paper submission, p. 3.

37 The AER, Aurora Energy and EnerNOC were supportive of the proposal while Ergon Energy, the Victorian DNSPs, Endeavour Energy and Essential Energy did not support the proposal.

38 Ergon Energy, Consultation Paper submission, p. 7.

39 Endeavour Energy, Consultation Paper submission, pp. 1-2; Ausgrid, Consultation Paper submission, pp. 4-5.

40 Ausgrid, Consultation Paper submission, pp. 6-7.

- carry out joint planning internally as a TNSP and DNSP; and
- prepare a transmission annual planning report in relation to dual function assets which are otherwise subject to the RIT-D. Due to the proposed timing requirements, Ausgrid also noted that it would not be possible for these separate reports to be published as a single document.

Ausgrid considered that the draft rule should provide for a more integrated process for DNSPs with dual function assets to review, plan and report on those assets in a way which is integrated into the process it carries as a DNSP.

Endeavour Energy requested that the final rule clearly articulate that dual function assets are to be treated as distribution assets for the purposes of planning and expansion under the rules.[41]

5.2 Draft rule

5.2.1 Description of the draft rule

The draft rule largely adopted the proposed rule in relation to the arrangements for the distribution annual planning review as described above, subject to a number of minor drafting amendments to improve and clarify its application. These amendments did not affect the principles underlying the proposed rule and are detailed in section 5.2.2 of the draft rule determination.[42]

5.2.2 Stakeholder views - second round of consultation

Scope and requirements of the distribution annual planning review

Energex was the only stakeholder to comment on the rules in respect of the requirements of the distribution annual planning review.[43] In its submission, Energex suggested several amendments be made to the drafting of a number of specific provisions under draft clause 5.13.1(d).[44] Details of these suggestions, and the Commission's response to each, are set out in Appendix A.

41 Endeavour Energy, Consultation Paper submission, pp. 1-2.

42 AEMC 2012, *Distribution Network Planning and Expansion Framework*, Rule Determination, AEMC, 14 June 2012, Sydney, pp. 22-23.

43 We note that Ergon Energy highlighted a formatting issue within draft clause 5.13.1(b).

44 Energex, Draft Rule Determination submission, pp. 2-3, 4-5.

Start of the forward planning period

A number of stakeholders reiterated the view that jurisdictions should be able to prescribe the start of the forward planning period.[45]

Ergon Energy and Energex considered that, where a jurisdiction has not specified a date for the commencement of the forward planning period, the default date should be 1 July to coincide with the start of the financial year. Energex noted this would accord with current Queensland reporting arrangements and efficiently align the planning period cycle into regulatory years.[46]

Endeavour Energy considered that the default DAPR date should be specified as 30 June (as opposed to 31 December). Endeavour Energy noted that New South Wales does not have a jurisdictionally mandated annual planning date and therefore, under the draft rule, it would be required to publish its DAPR by 31 December covering the forward planning period commencing 1 January. Endeavour Energy noted that, given its network predominately experiences peak loading during summer, it has traditionally aligned its planning practices to ensure a forward plan is in place prior to the start of summer each year.

5.3 Differences between the draft rule and final rule

Having regard to the views of stakeholders and its own analysis and review, the Commission has largely adopted the draft rules in relation to the arrangements for the distribution annual planning review, subject to a number of minor amendments to improve and clarify its application. The manner and reasoning for these amendments is set out below.

5.3.1 Amendments

The Commission has made a number of additional, minor amendments to improve and clarify the application of the final rule without affecting the principles underlying it. These changes are as follows:

- *Start of the forward planning period*: the final rule omits reference to the forward planning period "beginning on the date one day after the DAPR date" in clause 5.13.2(b).

- *Other minor changes*: to reflect comments made in submissions to the draft rule determination, the final rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details on these amendments.

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45 ENA, Draft Rule Determination submission, p.2; Ergon Energy, Draft Rule Determination submission, p.6; Energex, Draft Rule Determination submission, pp.1, 3-4; Endeavour Energy, Draft Rule Determination submission, p. 1.

46 Energex noted that it currently publishes its Network Management Plan on 31 August for the financial year period. Therefore, 1 July would provide a retrospective start date.

5.4 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request for the distribution annual planning review. Outlined below is the Commission's assessment of the final rule, including the reasons why it considers this aspect of the final rule meets the NEO.

5.4.1 Scope and requirements of the review

Relative to current arrangements, the proposed rule sought to introduce greater prescription regarding the scope and requirements of the distribution annual planning process. The proposed rule maintained the current minimum five year forward planning horizon, but clarified that the planning process must encompass all assets owned, and activities undertaken, by each DNSP which may materially affect the performance of their distribution networks.

In the draft rule determination, the Commission commented that replacing the current arrangements with a comprehensive, clearly defined annual planning process would assist DNSPs in making efficient planning decisions by requiring them, over a reasonable period, to identify and address potential problems in respect of their networks.

In addition, the Commission noted that the introduction of a process which was consistent across NEM jurisdictions should assist market participants and third parties in making better, more informed planning and investment decisions. This was because a common approach to distribution network planning could be expected to lower the cost and complexities associated with understanding DNSPs decision making processes. This would be particularly relevant for investors and market participants seeking to operate across jurisdictions.

Having considered the views put forward by stakeholders in submissions to the draft rule determination, the Commission maintains its view set out in the draft rule determination on this matter.

Start of the forward planning period

The consultation paper for this rule change request sought views from stakeholders on the implications of allowing each jurisdiction to determine the start of the forward planning period for DNSPs in that jurisdiction.[47] While the majority of DNSPs noted

47 In its Distribution Network Planning and Expansion Review, the AEMC recommended that DNSPs be required to publish their DAPRs by 31 December each year, covering the forward planning period starting 1 January the following year. The rule change request subsequently lodged by the MCE provided for each jurisdiction to determine the start date for the forward planning period by setting the date on which DNSPs must have published their DAPRs. The amendment was intended to allow for the planning process to reflect the seasonal variability of electricity demand in each jurisdiction.

support for a jurisdiction specified start date,[48] other stakeholders considered there would be benefit in implementing a uniform start date applicable to all DNSPs.[49]

In its draft rule determination, the Commission considered that jurisdictions ought to be able to determine the start date for the forward planning period for DNSPs in their jurisdictions. The Commission considered that differences in DNSPs' forward planning periods was less important than providing consistency and transparency in the requirements of the distribution annual planning review and report.[50] In addition, the Commission recognised that a move to a uniform forward planning period could potentially result in a large, potentially disproportionate impact on those DNSPs who would subsequently be required to alter existing internal planning practices and timeframes in order to comply with a uniform start date.

The draft rule therefore sought to provide flexibility for jurisdictions to determine the start of the forward planning period by providing for each jurisdiction to specify the date by which DNSPs in their jurisdictions must publish their DAPRs. The forward planning period would then commence "on the date one day after the DAPR date".[51]

In submissions to the draft rule determination, some stakeholders expressed concern that, as drafted, the rule did not provide adequate flexibility for jurisdictions to prescribe the start of the forward planning period.[52] These stakeholders considered that the requirement that the forward planning period begin one day after the DAPR date would be particularly problematic for those DNSPs whose current forward planning period commences prior to publication of the current annual planning report.

Having considered these concerns in detail, reference to the forward planning period “beginning on the date one day after the DAPR date” has been omitted from the final rule. We note that:

- clause 5.13.1(a)(1) specifies that a DNSP must “determine an appropriate forward planning period for its distribution assets”; and
- clause 5.13.1(b) states that “the minimum forward planning period for the purposes of the annual planning review is 5 years”.

These provisions are sufficient to require DNSPs to plan and report over a forward, minimum five year, period commencing on a date deemed appropriate by each DNSP.

In the instance that a jurisdiction has not specified a DAPR date under jurisdictional legislation, the draft rule includes a default date which requires DNSPs to publish their DAPR by 31 December. It is appropriate to specify a default date in the final rule to

48 ENA, Ergon Energy, Energex, Victorian DNSPs, Aurora Energy, Ausgrid, Endeavour Energy, ETSA Utilities, Essential Energy and Origin.

49 AER, EnerNOC.

50 The distribution annual reporting requirements are considered further in Chapter 6.

51 Draft clause 5.13.2(b).

52 ENA, Ergon Energy, Energex and Endeavour Energy.

provide clarity in respect of DNSPs' planning and reporting obligations and avoid confusion in the instance a jurisdiction has not specified a DAPR date.

5.4.2 Treatment of dual function assets

In submissions to the consultation paper, several stakeholders sought clarity on the treatment of dual function assets within the proposed annual planning and reporting arrangements.[53] Dual function assets predominately form part of a distribution network and provide support to, and operate in parallel with, a transmission network. Currently, the NER requires DNSPs who own and operate dual function assets to register as TNSPs by virtue of the definition of 'TNSP' in the rules. However, certain parts of the rules treat dual function assets in the same way as distribution assets (as opposed to transmission assets).

While the proposed rule did not propose to change the current approach to the treatment of dual function assets in the context of network planning and expansion, the Commission acknowledged there was some ambiguity within the proposed rule which could benefit from further clarity. The draft rule therefore included a number of minor amendments to provide for a more integrated approach (where possible) for NSPs that hold obligations both as owners of distribution assets and dual function assets.

No specific comments were received from stakeholders in submissions to the draft rule determination in respect of the treatment of dual function assets in the draft rule. The final rule is therefore consistent with the arrangements in the draft rule.

In summary: for the purposes of network annual planning and reporting, dual function assets will generally be treated in the same manner as transmission assets; for the purposes of project assessment, dual function assets will be treated in the same manner as distribution assets. More specifically, the obligations on the owners and operators of dual function assets are as follows:[54]

- *Annual planning review*: a DNSP with dual function assets will be required to conduct:
  - a transmission annual planning review for those dual function assets as a TNSP;[55] and
  - a distribution annual planning review for distribution assets as a DNSP.[56]
- *Annual planning report*: a DNSP with dual function assets will have the option of publishing a single distribution annual planning report by the relevant DAPR date.[57] The content of the report is to include:

53 Endeavour Energy and Ausgrid.

54 A number of these obligations are discussed further in later chapters.

55 Clause 5.12.1.

56 Clause 5.13.1.

- for dual function assets, the requirements of the transmission annual planning report (TAPR);[58] and
- for distribution assets, the requirements of the DAPR.[59]

- *TNSP-DNSP joint planning obligations*: an NSP with dual function assets:
  - in its capacity as a TNSP, will not be a TNSP for the purposes of carrying out joint planning under draft clause 5.14.1;[60] and
  - in its capacity as a DNSP, will be required to carry out joint planning in accordance with draft clause 5.14.1 in respect of its dual function assets and distribution assets with the TNSP of the transmission networks to which the DNSP's network is connected.[61]
- *Project assessment process*: projects where a potential credible option to address an identified need includes expenditure on a dual function asset, will be subject to assessment under the RIT-D;[62]
- *Project assessment process for joint planning projects*: joint planning projects which include the possibility of expenditure on dual function assets will be subject to assessment under the RIT-T in all cases where at least one potential credible option to address an identified need contains a network or non-network option on a transmission network with an estimated capital cost greater than $5 million.[63]

5.5 Rule making test

The Commission is satisfied that the arrangements in respect of the distribution annual planning review set out in the final rule will, or are likely to, better contribute to the achievement of the NEO than the proposed rule. The final rule is likely to promote efficient investment in, and efficient operation of, distribution networks for the long term interests of consumers through:

- establishing a clearly defined and efficient planning process which facilitates the timely identification and resolution by DNSPs of potential problems on their networks, thereby promoting efficient operation of the network; and

57 Clause 5.12.2(b).

58 Clause 5.12.2(c).

59 Clause 5.13.2 and schedule 5.8.

60 Clause 5.14.1(c).

61 Clause 5.14.1(a)(1).

62 Clause 5.17.3(b). See Chapter 9 for further discussion on this matter.

63 Clause 5.14.1(d)(4)(ii) and clause 5.10.2 (local definition of "RIT-T project"). See Chapter 8 for further discussion on this matter.

- providing a clearly defined and efficient planning process which includes a robust economic assessment will help to ensure that DNSPs make efficient investment decisions in respect of their networks, thereby promoting efficient investment in the network.

6 Distribution annual planning report

This chapter sets out the Commission's views in relation to the distribution annual planning report (DAPR), having regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 6.1 describes the proposed DAPR requirements and summarises stakeholder responses to the first round of consultation on this matter;
- section 6.2 describes the DAPR requirements set out in the draft rule and summarises stakeholder responses to the second round of consultation on this matter;
- section 6.3 sets out the differences between the draft rule and the final rule;
- section 6.4 sets out the Commission's assessment of the final rule in respect of the DAPR; and
- based on the Commission's assessment in section 6.4, section 6.5 sets out the Commission's conclusions on this matter.

6.1 Proposed rule

6.1.1 Description of the proposed rule

The proposed DAPR was designed to report on the outcomes of each DNSPs' distribution annual planning review. The proposed rule contains a number of key elements. These include requiring that the DAPR:

- be published by the applicable jurisdictional specified date each year;
- be certified by the CEO and a director or company secretary;
- include forecasting information over the forward planning period, including capacity and load forecasts at the sub-transmission and zone substation level, and, to the extent possible, primary distribution feeders;
- identifies system limitations which may include limitations resulting from forecast load exceeding total capacity, the need for asset refurbishment or the need to improve system security;
- reports on investments that have been (or will be) assessed under the RIT-D (including consultation undertaken in accordance with the demand side engagement strategy, estimated capital cost and impacts that may arise for connection and distribution use of system (DUOS) charges);

- provides details of all other committed projects with a capital cost of $2 million or greater that were 'urgent and unforseen' or replacements and refurbishment projects;
- reports on other information including:
  - a description of the network;
  - regional development plans;
  - outcomes from joint planning undertaken with TNSPs and other DNSPs;
  - performance standards and compliance against those standards; and
  - a summary of the DNSP’s asset management methodology; and
- provides a summary of the DNSP’s activities and actions to promote non-network initiatives, including embedded generation, and information on any significant investments in metering services.

The proposed rule also specifies that certain third parties (such as a registered participant, connection applicant, intending participant or a stakeholder registered on the demand side engagement register) would be able to request a public forum on the DAPR. The DNSP would be required to conduct the requested public forum within three months of the publication of the DAPR.

In addition, the proposed rule provides the AER to grant exemptions from, or variations to, the annual reporting requirements where a DNSP can demonstrate in an application to the AER that, due to the DNSP’s operational or network characteristics, the costs of preparing the data would manifestly exceed any benefit that may reasonably be obtained from reporting the relevant data.

Current arrangements

Currently, the NER does not require DNSPs to publish the results of their planning activities with respect to distribution assets. However, the majority of jurisdictions have in place arrangements which require DNSPs to prepare, and in most cases publish, an annual planning report.[64] While the jurisdictional reporting requirements tend to be similar in their objectives (that is, to report on emerging constraints on the distribution network), the scope, content and timeframes for reporting differ significantly across jurisdictions.

It is intended that the DAPR requirements set out in the proposed rule will replace existing jurisdictional reporting requirements. While the content of the DAPR maintains the core of existing jurisdictional requirements, the proposed rule provides flexibility for jurisdictions to retain any additional, jurisdictional specific requirements, where appropriate.

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64 The exception to this is the Australian Capital Territory (ACT).

6.1.2 Proponent's view

The rule change request states that the purpose of the proposed national annual reporting requirements is to provide a more consistent and comprehensive annual reporting regime for DNSPs across the NEM. It claims that replacing the existing reporting and publication requirements with the requirements to prepare and publish a DAPR would provide transparency to DNSPs' decision making processes, thereby assisting non-network providers, TNSPs and connection applicants to make efficient investment decisions.

The proponent also states that the DAPRs could be used by regulators such as the AER to understand the activities undertaken by DNSPs and how they are developing their networks.

6.1.3 Stakeholder views - first round of consultation

Certification of the DAPR

In submissions to the consultation paper, several stakeholders noted that they did not support the proposed DAPR certification requirements. The ENA and Victorian DNSPs considered that certification by the CEO and a director or company secretary was inappropriately onerous.[65] As an alternative, these stakeholders suggested certification by the CEO or relevant general manager would be more appropriate. In addition, given the scope of the information reported in the DAPR, Essential Energy suggested sign off by an executive manager may be a better alternative.[66]

Public forum on the content of the DAPR

In their joint submission, the Victorian DNSPs considered that the requirement to hold a public forum at the request of any member of the public may leave a DNSP open to vexatious claims.[67] Further, the Victorian DNSPs considered that public forums were not an effective or informative method for communicating highly technical issues which require careful consideration of details and facts set out in the reports.

Exemptions or variations to the reporting requirements

Around half of the submissions to the consultation paper expressed support for the proposal to allow the AER to grant exemptions or variations to the proposed annual reporting requirements.[68]

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65 ENA, Consultation Paper submission, p. 9; Victorian DNSPs, Consultation Paper submission, p. 3.

66 Essential Energy, Consultation Paper submission, pp. 5-6.

67 Victorian DNSPs, Consultation Paper submission, p. 4.

68 ENA, Consultation Paper submission, p. 8; Ergon Energy, Consultation Paper submission, p. 8; Energex, Consultation Paper submission, p. 3; Victorian DNSPs, Consultation Paper submission, p. 9; Endeavour Energy, Consultation Paper submission, pp. 4, 11; Essential Energy, Consultation Paper submission, p. 5; EnerNOC, Consultation Paper submission, p. 4; Ausgrid, Consultation Paper submission, p. 4; Essential Energy, Consultation Paper submission, p. 5.

Essential Energy considered the proposal would provide a mechanism to balance the circumstances of a DNSP with jurisdictional requirements and would provide DNSPs with time to develop systems to comply with the national framework.[69] In addition, Ausgrid considered the rules should be flexible to reflect current planning processes unless there was a clear reason that current processes were inadequate.[70]

Ergon Energy considered, at the very least, exemptions should apply when requested during transitional periods.[71] Similarly, Endeavour Energy considered the ability to seek an exemption would be more efficient in situations where the application of jurisdictional requirements and the national framework lead to a duplication of processes.[72]

In contrast, several stakeholders did not support the proposal to allow exemptions or variations to the proposed annual reporting requirements.[73] The AER considered the information proposed for inclusion in the DAPR was essential information which, for the most part, should be considered by DNSPs in undertaking current planning activities. It considered that disclosure of this information would be unlikely to result in unwarranted additional cost or regulatory burden.[74] In addition, Aurora Energy considered that there should be no reason for exemptions from, or variations to, the annual reporting requirements unless the information was not available.[75]

Stakeholders also expressed various views in relation to the specific schedule 5.8 reporting requirements. These comments are set out in Appendix A of the draft rule determination.

6.2 Draft rule

6.2.1 Description of the draft rule

The draft rule largely adopted the proposed rule in relation to the arrangements for the DAPR as described above, subject to a number of modifications considered to improve its application and better promote the NEO. The modifications made to the proposed rule were as follows:

- *Default DAPR date*: where a DAPR date (previously the 'jurisdiction specified date') is not been specified by a jurisdiction, the draft rule required a DNSP to

69 Essential Energy, Consultation Paper submission, p.5.

70 Ausgrid, Consultation Paper submission, p.4.

71 Ergon Energy, Consultation Paper submission, p. 8.

72 Endeavour Energy, Consultation Paper submission, pp. 4, 11.

73 AER, Consultation Paper submission, p. 3; Origin, Consultation Paper submission, p. 1; AEMO, Consultation Paper submission, p. 1; Aurora Energy, Consultation Paper submission, p. 4.

74 AER, Consultation Paper submission, p. 3.

75 Aurora Energy, Consultation Paper submission, p. 4.

publish its DAPR by 31 December for the forward planning period beginning 1 January.[76]

- *Certification of the DAPR*: the draft rule removed the obligation for DAPRs to be certified by the CEO and a director or company secretary of the DNSP.[77]

- *Public forum on the content of the DAPR*: the draft rule removed the obligation on DNSPs to conduct a public forum on their DAPRs if requested to do so by a relevant party. However, the draft rule included a new obligation on DNSPs to provide a contact person who can field queries from any party on the content of the DAPR. The relevant contact details would be included on each DNSPs website.[78]

- *Exemptions or variations to the annual reporting requirements*: the draft rule removed the ability for the AER to grant exemptions or variations to the annual reporting requirements as set out in draft schedule 5.8.[79]

The Commission also made a number of minor drafting amendments considered to improve and clarify the application of the DAPR requirements. These amendments did not affect the principles underlying the proposed rule and are detailed in section 6.2.2 of the draft rule determination.[80]

6.2.2 Stakeholder views - second round of consultation

Certification of the DAPR

The Clean Energy Council (CEC) expressed concern that the Commission had removed the requirement for certification of the DAPR at the executive level. The CEC considered that while there may be structural reasons for DNSPs to argue against this, DNSPs should also be willing to be held accountable for their investment decisions.[81]

Schedule 5.8 reporting requirements

The ENA, Energex and Ergon Energy all expressed concern that many of the DAPR reporting requirements relating to the RIT-D duplicated information already available under the RIT-D process.[82] The ENA submitted that requiring DNSPs to duplicate this information would result in significant implementation and ongoing costs for DNSPs while Energex considered it would significantly increase the size of the DAPR. Ergon

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76 Draft clause 5.13.2(b).

77 Proposed clause 5.6.2AA(s).

78 Proposed clause 5.6.2AA(r) and draft clause 5.13.2(e).

79 Proposed clauses 5.6.2AA(u)-(w).

80 AEMC 2012, *Distribution Network Planning and Expansion Framework*, Rule Determination, AEMC, 14 June 2012, Sydney, pp. 33-34.

81 CEC, Draft Rule Determination submission, p. 3.

82 ENA, Draft Rule Determination submission, p. 2; Energex, Draft Rule Determination submission, p. 2; Ergon Energy, Draft Rule Determination submission, p. 8.

Energy suggested that, for information available elsewhere, a specific reference to that source in the DAPR would be sufficient.

Aurora Energy noted that much of the information required in the DAPR was requested by the AER in the draft regulatory information notice (RIN) used for monitoring Aurora's compliance with its distribution determination. As a consequence, Aurora noted that it would need to present the same information in two different ways in order to meet is regulatory obligations. It considered this would be resource intensive and potentially result in a reduction in transparency.[83]

Energex and Ergon Energy provided a significant number of detailed comments in respect of the reporting requirements set out in draft schedule 5.8.[84] The CEC and Essential Energy also made a number of suggestions in relation to specific reporting requirements set out in the schedule.[85] Details of these comments, and the Commission's response to each, are set out in Appendix A.

In addition, the CEC noted its support for the proposed content of the DAPR and considered the report will meet the objective of providing information on the outcomes of the planning review.[86]

Exemptions or variations to the reporting requirements

Energex, Ergon Energy and Essential Energy did not support removal of the ability for the AER to grant exemptions or variations to the annual reporting requirements.[87] Energex suggested that inclusion of this clause would not result in inconsistency with regard to annual reporting across jurisdictions on the basis that the circumstances in which the AER would grant such an exemption or variation would be limited. In addition, both Energex and Ergon Energy noted that a DNSP would only ever initiate such an application where it was clear that the DNSP could not meet a requirement, or where the cost of providing the information would clearly outweigh the benefit. These stakeholders requested that the AEMC consider reinserting this provision.

Essential Energy reaffirmed its view that providing the AER with the ability to grant an exemption or variation to the content of the DAPR was particularly important during transition from jurisdictional to national reporting, and until DNSPs had systems in place to comply with the more onerous national requirements.

In contrast, the CEC noted that it supported the Commission's position on the removal of the ability of the AER to provide exemptions and variations to the DAPR reporting

83 Aurora Energy, Draft Rule Determination submission, p. 2.

84 Energex, Draft Rule Determination submission, pp. 6-10; Ergon Energy, Draft Rule Determination submission, pp. 7-8.

85 CEC, Draft Rule Determination submission, pp. 3-4; Essential Energy, Draft Rule Determination submission, p. 2.

86 CEC, Draft Rule Determination submission, p. 2.

87 Energex, Draft Rule Determination submission, p. 2; Ergon Energy, Draft Rule Determination submission, p. 7; Essential Energy, Draft Rule Determination submission, p. 2.

requirements.[88] While not explicitly offering support, the Victorian DNSPs noted that they accept the Commission's reasoning for removing AER exemptions or variations to the annual reporting requirements.[89]

Other comments

In their joint submission, the Victorian DNSPs expressed strong support for the removal of (among other things) the requirements in relation to consistent start dates for the DAPR, a public forum on the contents of DAPR, certification of the DAPR by the CEO and a director or company secretary, and specific review and audit powers for the AER in relation to DNSPs' consideration of non-network options. The Victorian DNSPs considered these requirements would otherwise add significantly to the costs of the annual planning process without delivering material benefit.[90]

Similarly, Ergon Energy welcomed the Commission's draft decision to remove (among other things) the requirement to conduct a public forum, certification of the DAPR and additional powers for the AER to review and audit a DNSPs consideration of non-network alternatives.[91]

In respect of the removal of the requirement for DNSPs to conduct public forums on the content of the DAPR, the CEC noted that although public forums are an important part of the stakeholder engagement process, DNSPs do not need a regulatory obligation to undertake this function. The CEC observed that DNSPs may not be engaged at the consumer level, which may be leading to concerns about DNSPs being exposed to vexatious claims. The CEC considered this raised issues in respect of DNSPs roles as essential service providers.[92]

6.3 Differences between the draft rule and final rule

Having regard to the views of stakeholders and its own analysis and review, the Commission has largely adopted the draft rules in relation to the DAPR, subject to a number of further minor amendments to improve and clarify its application. The manner and reasoning for these amendments are set out below.

6.3.1 Amendments

The Commission has made a number of additional drafting amendments to improve and clarify the application of the final rule without affecting the principles underlying it. These drafting changes are as follows:

88 CEC, Draft Rule Determination submission, p. 2.

89 Victorian DNSPs, Draft Rule Determination submission, p. 3.

90 Victorian DNSPs, Draft Rule Determination submission, p. 2.

91 Ergon Energy, Draft Rule Determination submission, p. 3.

92 CEC, Draft Rule Determination submission, p. 2.

- *S5.8(b)(2)(vi) regarding forecasts for the forward planning period*: the final rule clarifies that DNSPs will only be required to provide "an estimate" of the number of hours per year that 95 per cent of peak load is expected to be reached, where applicable.

- *S5.8(b)(2)(ix) regarding forecasts for the forward planning period*: the final rule clarifies that DNSPs will only be required to provide generation capacity of "known" embedded generating units.

- *S5.8(b)(5) regarding forecasts for the forward planning period*: the final rule clarifies that DNSPs will only be required to provide "a description" (rather than "forecasts") of any factors which may have a material impact on its network. The list of factors has also been broadened to include “the quality of supply to other Network Users (where relevant)".

- *S5.8(c))(1) regarding information on system limitations*: the final rule clarifies that in providing estimates of the timing of a system limitation, identification of the year and "month(s)" (rather than single month) is sufficient.

- *S5.8(c))(4) regarding information on system limitations*: the final rule clarifies that a "brief" discussion of the "types of" potential solutions that may address a system limitation in the forward planning period is sufficient.

- *S5.8(c)(5)(iii) regarding information on system limitations*: the final rule clarifies that DNSPs may provide information on the estimated reduction in forecast load in megawatts (MW) "or improvements in power factor" needed to defer a forecast system limitation.

- *S5.8(d) regarding information on primary distribution feeders*: the final rule clarifies that DNSPs are only required to report information on primary distribution feeders for which a DNSP has prepared forecasts of maximum demands under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years. In addition, the final rule clarifies that an overload is considered to have occurred “where load exceeds, or is forecast to exceed, 100% (or other utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods)”.

- *S5.8(d)(6) regarding information on primary distribution feeders*: the final rule clarifies that for overloaded primary distribution feeders which have been identified by a DNSP, the DNSP must provide information on "the types of potential solutions which may address an overload or forecast overload"(rather than "any technically feasible options being considered by a DNSP").

- *S5.8(e) regarding information on investments*: the final rule makes a number of minor amendments to clarify that only "high-level" summary information is required to be reported on each RIT-D project for which a RIT-D has been completed in the preceding year or in progress.

- *S5.8(g) regarding information on investments*: the final rule makes a number of minor drafting amendments to clarify that only "summary" information is required to be provided for the description in the DAPR of committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more that are to address either a refurbishment or replacement need, or an urgent and unforseen network issue.

- *S5.8(h) and (I) regarding information on joint investments*: the final rule makes a number of minor drafting amendments to clarify that only "a brief description" of any investments which have been planned through the joint planning process is required to be provided.

- *S5.8(j) regarding information on reliability and quality of supply measures and standards*: the final rule makes a number of minor drafting amendments to ensure the terminology used is appropriate to capture the reliability standards and measures with which the DNSP must comply.

- *Other minor changes*: to reflect comments made in submissions to the draft rule determination, the final rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the drafting issues log set out in Appendix B, provide further details on these amendments.

6.4 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request for the DAPR. Outlined below is the Commission's assessment of the final rule, including the reasons why it considers this aspect of the final rule meets the NEO.

6.4.1 Publication of the DAPR

The proposed rule sought to require DNSPs to publish their DAPRs on their website by the date specified by the relevant jurisdiction. In the draft rule determination, the Commission noted that it considered this obligation would be a cost effective means of improving the transparency and accessibility of the information contained in the reports. Making this information publicly available in a timely manner would be likely to assist network users (including non-network proponents) to make more informed and efficient investment decisions. In addition, network users will have access to the most recent information available which should assist them in considering where best to connect to the network, thereby promoting efficient use of electricity services.

The Commission also noted that annual publication of the outcomes of each DNSP's annual planning review should also assist the AER in performing its regulatory activities by providing easily accessible information on a more frequent basis than is currently the case under the five year regulatory control period.

To help avoid confusion in the instance that a jurisdiction had not specified a date by which DNSPs in that jurisdiction must publish their DAPRs, the draft rule introduced a new provision which specified that, where a DAPR date is not specified under jurisdictional legislation, DNSPs would be required to publish their DAPR by 31 December. The Commission considered inclusion of a default date in the draft rule would increase clarity in respect of DNSPs' planning and reporting obligations.

Having considered the arguments and evidence put forward in submissions to the draft rule determination in relation to the arrangements for publication of the DAPR, the Commission maintains its view set out in the draft rule determination.[93]

Public forum on the DAPR

The proposed rule required DNSPs to conduct a public forum on their DAPRs within three months of the report being published each year, if requested to do so by a relevant party.[94] This requirement was intended to increase the opportunity for stakeholders to understand the information contained in the DAPR, through direct engagement with DNSPs.

In the draft rule determination, the Commission noted that while it was supportive of the intent of this proposal, it nonetheless agreed with the views of the Victorian DNSPs that a public forum was not necessarily the most effective way of communicating to third parties the type of information proposed to be included in the DAPRs.[95] For this reason, this obligation was omitted from the draft rule. In its place, the Commission included a new obligation that DNSPs provide on their website the details of a relevant contact person who could field queries from any party on the content of the DAPR. In contrast to the proposed rule, the Commission considered this obligation provided a more cost effective means of providing an avenue for discussion on the relevant parts of the DAPR, to increase stakeholders understanding of the contents of the DAPR, without being onerous on DNSPs.

Having regard to the views put forward in submissions to the draft rule determination in relation to the requirement for DNSPs to conduct a public forum on the content of the DAPR, the Commission maintains its view set out in the draft rule determination. However, as noted by the CEC, this does not prevent a DNSP hosting a forum if it considers it appropriate.

Certification of the DAPR

The proposed rule included a requirement that DAPRs be certified by the CEO and a director or company secretary of the DNSP. This requirement was intended to ensure that the reports met the necessary regulatory requirements and accurately represented the policies and practices of the DNSP, thereby increasing confidence of market participants and third parties in the accuracy of the content of the DAPR.

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93 We recognise that issues around the DAPR date are closely linked to issues in respect of the forward planning period. See section 5.4 for further discussion on these matters.

94 A relevant party being a registered participant, connection applicant, intending participant or a stakeholder registered on the DNSPs demand side engagement register.

95 Victorian DNSPs, Consultation Paper submission, p. 4.

In submissions to the consultation paper, a number of stakeholders considered that this obligation was inappropriately onerous.[96] In the draft rule determination, the Commission agreed with this view and noted that there were already a number of regulatory mechanisms and incentives to encourage the delivery of robust, high quality DAPRs in line with the rules. For these reasons, the Commission omitted this requirement from the draft rule.

Noting that stakeholders generally did not oppose this aspect of the draft rule in submissions to the draft rule determination, the Commission maintains its view set out in the draft rule determination on this matter.

6.4.2 Content of the DAPR

The purpose of the DAPR is to inform on the outcomes of each DNSPs annual planning review. The DAPR reporting requirements set out in schedule 5.8 focus on the identification of system limitations on a distribution network, with particular emphasis on sub-transmission assets, zone substations and, where the information is available, primary distribution feeders. To support key information on system limitations, the reporting requirements also require DNSPs to include a range of additional information in their DAPRs. This additional information, to be provided at a high level only, is intended to provide important context to DNSPs' planning processes and activities.

In the draft rule determination, the Commission considered that the DAPR reporting requirements would provide a consistent and comprehensive annual reporting regime for DNSPs across the NEM. By improving the level of transparency around DNSPs' planning processes and activities, the DAPR would be likely to assist network users in making better informed and more efficient investment decisions. In addition, non-network providers would be provided with information on possible investment opportunities allowing them to efficiently plan and potentially offer more cost effective solutions to network investment.

Further, the Commission considered that by improving the level of information available to the market, the reporting requirements should help to reduce information asymmetries between the AER and DNSPs, thereby assisting the AER in its distribution determination processes.

In addition, the introduction of nationally consistent arrangements should lower the cost and complexities associated with understanding DNSPs decision making processes, particularly for investors and market participants seeking to operate across jurisdictions. This should promote efficient decision making by market participants, and hence promote efficient investment in electricity services.

Having considered the views in submissions to the draft rule determination, the Commission maintains its views set out in the draft rule determination on this matter.

96 ENA, Consultation Paper submission, p. 9; Victorian DNSPs, Consultation Paper submission, p. 3.

Exemptions or variations to the reporting requirements

The proposed rule empowered the AER to grant exemptions or variations to the annual reporting requirements where a DNSP was able to demonstrate to the AER that, due to its operational or network characteristics, the costs of preparing the data would manifestly exceed any benefit that may be reasonably obtained from reporting that data in a national regime. The proponent considered that this requirement was necessary to balance the cost to a DNSP of preparing the DAPR with the benefits to stakeholders from reporting.

In the draft rule determination, the Commission recognised that in some circumstances, it may be appropriate for the rules to provide some flexibility to cater for differences in local circumstances. However, the Commission did not consider that the inclusion of a broad exemption clause was the best means of providing flexibility in this instance. Instead, it preferred to focus on refining the reporting requirements set out in schedule 5.8 such that they are appropriate and fit for purpose for all DNSPs.

The draft rule therefore omitted the provision which allowed the AER to grant exemptions or variations to the schedule 5.8 reporting requirements. However, in the draft rule determination, the Commission requested feedback from stakeholders on whether any of the reporting requirements set out in draft schedule 5.8 were likely to be particularly problematic and the reasons why.

As noted in section 6.2, Energex and Ergon Energy provided a significant number of detailed comments in respect of the reporting requirements set out in draft schedule 5.8 in their submissions to the draft rule determination. These DNSPs made a number of suggestions in respect of the drafting of several of the reporting requirements. In some cases, Energex and Ergon Energy claimed that reporting certain information would necessitate system changes which would be both time consuming and costly. These stakeholders therefore suggested that several provisions be removed to reduce unnecessary compliance costs.

Having considered each of the comments and suggestions put forward by Energex and Ergon Energy, the Commission has made a number of drafting amendments to improve and clarify the application of the final rule. These amendments are detailed in section 6.3 and Appendix A of this final determination. In respect of the suggestions which the Commission has chosen not to pursue, there are several points to note:

- *Compliance costs*: The DAPR reporting requirements specified in schedule 5.8 of the final rule have been designed to maintain the core of existing jurisdictional requirements. However, the move to a nationally consistent reporting regime will inevitably necessitate some change to DNSP systems and processes. On the basis that most of the information proposed for inclusion in the DAPRs is key information which should be considered by DNSPs in undertaking their current planning activities, these additional compliance costs should not be excessive. In addition, we note that it is likely that the costs of complying with the DAPR reporting requirements will fall over time as DNSPs develop their understanding of the new obligations and discover efficiencies in their planning and reporting processes.

- *Reporting on potential solutions to address forecast system limitations*: A key objective of the DAPRs is to provide sufficient information to allow non-network proponents to consider, and where appropriate develop, non-network solutions as alternatives to network investment to address potential system limitations. By requiring DNSPs to consider and report on, for example, possible solutions to address forecast system limitations, non-network providers will be provided with a valuable early indication of potential investment opportunities in the forward period. While collating and reporting this information may initially impose compliance costs on some DNSPs who do not report this information at present, these costs will be outweighed by the benefits of providing non-network providers with greater transparency around potential investment opportunities which can then be exploited through further dialogue with DNSPs.

- *Reporting on primary distribution feeders*: Several stakeholders expressed concern in relation to the reporting requirements for primary distribution feeders. Under industry best practice, we would expect DNSPs to regularly identify and plan for overloaded primary distribution feeders. However, DNSPs are only required to report on those primary distribution feeders for which a DNSP has prepared forecasts under 5.13.1(d)(1)(iii) and which are forecast to experience an overload. As noted above, information on any overloaded primary distribution feeders would enhance the ability of non-network proponents to identify feasible opportunities for non-network alternatives. To avoid any doubt about what is required to be reported for primary distribution feeders, the final rule includes a number of drafting amendments which are detailed in section 6.3 and Appendix A.

- *Reporting on RIT-D assessments*: Some stakeholders suggested that many of the DAPR reporting requirements relating to the RIT-D would duplicate information already available in the RIT-D project assessment reports. However, the RIT-D project assessment reports and the DAPRs differ in their objectives. While the RIT-D project assessment documentation will provide specific, detailed information on a DNSPs assessment of each RIT-D project, the DAPR will set out a high level summary of the RIT-D assessments undertaken by a DNSP in the preceding year. Inclusion of high level summary information in the DAPR allows the outcomes of the planning process to be captured in an accessible format, in a central location. To avoid any doubt that only key, high level information is required to be provided under schedule 5.8(e), the final rule includes a number of minor drafting amendments which are detailed in section 6.3 and Appendix A.

6.5 Rule making test

The Commission is satisfied that the arrangements in respect of the DAPR set out in the final rule will, or are likely to, better contribute to the achievement of the NEO than the proposed rule. The final rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity through:

- introducing transparent, nationally consistent planning arrangements which should facilitate efficient planning and investment decisions by DNSPs and other relevant parties when operating in the NEM;
- providing consistent and clearly defined reporting requirements for DNSPs in all participating jurisdictions which should provide regulatory certainty and assist DNSPs in making efficient planning decisions, thereby promoting efficient investment in distribution networks;
- assisting network users in understanding how the timing and location of connections might affect capability of the network and the need for augmentations or non-network options, thereby promoting the efficient use of electricity services; and
- balancing the benefits of reporting information on DNSPs network planning activities with the costs of doing so, thereby promoting good regulatory practice.

7 Demand side engagement strategy

This chapter sets out the Commission’s views in relation to the demand side engagement obligations, having regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 7.1 describes the proposed demand side engagement strategy and summarises stakeholder responses to the first round of consultation on this matter;
- section 7.2 describes the demand side engagement obligations set out in the draft rule and summarises stakeholder responses to the second round of consultation on this matter;
- section 7.3 sets out the differences between the draft rule and the final rule;
- section 7.4 sets out the Commission's assessment of the final rule in respect of the demand side engagement obligations; and
- based on the Commission's assessment in section 7.4, section 7.5 sets out the Commission's conclusions on this matter.

7.1 Proposed rule

7.1.1 Description of the proposed rule

The proposed rule contains a number of obligations on DNSPs in respect of their engagement with non-network providers during the annual planning process. This includes requiring that DNSPs:

- engage with non-network providers and consider non-network options at the planning stage; and
- develop a demand side engagement strategy.

The proposed demand side engagement strategy would require DNSPs to:

- prepare and publish a *demand side engagement document* that sets out its process and procedures for engaging with non-network providers and assessing non-network options as alternatives to network investment;
- establish, maintain and publish a *demand side engagement database* of non-network proposals and/or case studies that demonstrate assessments it has undertaken in considering non-network proposals; and
- establish and maintain a *demand side engagement register* for parties wishing to be advised of relevant developments related to a DNSP's planning activities.

DNSPs would need to publish the first demand side engagement document by the date nine months after the commencement of the rule. The proposed rule also requires DNSPs to review and publish the demand side engagement strategy at least once every three years.

The demand side engagement strategy is intended to recognise the importance of proactive engagement between DNSPs and non-network providers in developing potential solutions to network constraints. This proposal was originally recommended in the AEMC's Distribution Network Planning and Expansion Review in response to stakeholder concerns that it can be difficult to engage with DNSPs at an appropriate stage in the planning process, and that there is limited transparency on how DNSPs assess and consider non-network options.

DNSPs in New South Wales and South Australia currently have in place comparable demand side obligations under jurisdictional instruments. The proposed rule builds on current industry practice to establish similar obligations at a NEM-wide level.

7.1.2 Proponent's view

The proponent considers that the introduction of a demand side engagement strategy would facilitate ongoing relationships between DNSPs and non-network providers, while also encouraging DNSPs to consider all feasible options for network development. In addition, the proponent suggests that greater transparency and consultation around how DNSPs consider alternative investment options will encourage DNSPs to develop and operate their networks more efficiently. This may ultimately result in lower network charges for end use customers.

7.1.3 Stakeholder views - first round of consultation

Demand side engagement strategy

The consultation paper asked stakeholders for their views on the benefits and costs associated with implementing the demand side engagement strategy. Overall, EnerNOC and the Total Environment Centre (TEC) considered the benefits of DNSPs developing a demand side engagement strategy would outweigh its cost.[97] Some DNSPs identified these costs as additional resources, information technology, publishing tools and businesses processes which would need to be established and maintained.[98]

More generally, Aurora Energy considered that its customer base would not be willing to pay the costs arising from implementation of the strategy, on the basis that the proposal is driven by a 'perceived' rather than an 'actual' failure.[99] The TEC suggested

97 EnerNOC, Consultation Paper submission, p.4; TEC, Consultation Paper submission, p. 4.

98 Energex, Consultation Paper submission, p. 2; Aurora Energy, Consultation Paper submission, p. 3; Endeavour Energy, Consultation Paper submission, p. 3; Victorian DNSPs, Consultation Paper submission, p. 14.

99 Aurora Energy, Consultation Paper submission, p. 3.

that the cost of developing the strategy could be passed through or recouped from demand side participation (DSP) projects.[100]

The ENA and Ergon Energy considered that the rule should provide for DNSPs to be able to apply for an exemption or variation to the demand side engagement strategy where, due to operational or resource reasons, the costs of complying would manifestly exceed any benefit that may be reasonably obtained from compliance.[101]

In addition, the ENA and Ausgrid considered that the most effective way to improve the uptake of non-network options was through clear and appropriate incentives, rather than prescriptive process requirements such as the proposed strategy.[102] As evidence of this, Ausgrid noted that in New South Wales (NSW), the D-factor incentive regime was more successful than the NSW Demand Management Code.[103] In addition, EnerNOC considered that DNSPs would need to cooperate with non-network providers for the demand side engagement strategy to work in practice.[104]

Demand side engagement document

Energex stated that the demand side engagement document should not contain or replicate information which is, or will be, publicly available elsewhere. For example, information provided through the connection process contained in Chapter 5A of the NER and associated publication requirements to be established under the NECF.[105] Energex considered that, for information available elsewhere, a specific reference to that source would be sufficient. In addition, Endeavour Energy did not see the need for a separate demand side engagement strategy given the requirements of the DAPR.[106]

Demand side engagement database

The majority of DNSPs who provided a submission to the consultation paper did not support the proposal to develop and maintain a database of non-network proposals and/or case studies.[107]

The ENA, Energex and the Victorian DNSPs considered the need to remove confidential information from the proposals would negate the value of the information within the database.[108] Similarly, Endeavour Energy considered the database would be

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100 TEC, Consultation Paper submission, p. 4.

101 ENA, Consultation Paper submission, p.6; Ergon Energy, Consultation Paper submission, p. 6.

102 ENA, Consultation Paper submission, p. 6; Ausgrid, Consultation Paper submission, p. 3.

103 Ausgrid, Consultation Paper submission, p. 3.

104 EnerNOC, Consultation Paper submission, p. 3.

105 Ergon Energy, Consultation Paper submission, p. 12.

106 Endeavour Energy, Consultation Paper submission, pp. 2-3.

107 ENA, Consultation Paper submission, p. 7; Ergon Energy, Consultation Paper submission, pp. 5, 13; Energex, Consultation Paper submission, p. 2; Victorian DNSPs, Consultation Paper submission, pp. 3, 9, 14; Endeavour Energy, Consultation Paper submission, pp. 2-3; Essential Energy, Consultation Paper submission, p. 4.

108 ENA, Consultation Paper submission, p. 7; Energex, Consultation Paper submission, p. 2; Victorian DNSPs, Consultation Paper submission, pp. 3, 9, 14.

difficult to implement due to the level of commercially sensitive information. It suggested that either the NER or an AER guideline provide a template for this information to minimise commercial sensitivities.[109]

Further, Ergon Energy considered that even though DNSPs would have discretion to select data to be published, there would be a risk of inadvertently disclosing commercially sensitive information on non-network proposals. Ergon Energy also noted that additional resources would be required to administer the database, and this may lead to reporting duplication given that detail of proposals would be published in the RIT-D project specification report.[110]

The Victorian DNSPs noted that the existence of the database would not, in itself, increase demand side participation, and would not aid in contributing to the NEO.[111]

Demand side engagement register

The ENA and Ergon Energy did not support the proposal for DNSPs to establish and maintain an individual register of interested parties. The ENA considered this was an inefficient and costly approach to facilitating information between DNSPs and non-network proponents and suggested a central repository would be more appropriate.[112] In addition, Ergon Energy considered that the proposal would undermine the development of a national market and increase the burden on non-network providers by requiring them to register separately with each DNSP. Ergon Energy also expressed support for a central registration system for non-network providers managed by AEMO.[113]

7.2 Draft rule

7.2.1 Description of the draft rule

The draft rule largely adopted the proposed rule in relation to the demand side engagement obligations described above, subject to a number of modifications considered to improve its application and better promote the NEO. The modifications made to the proposed rule were as follows:

- *Demand side engagement database*: the draft rule removed the obligation on DNSPs to establish, maintain and publish a database of non-network proposals and/or case studies as part of the demand side engagement strategy.[114] However, a number of additional requirements were added to the demand side engagement document requiring DNSPs to provide, where possible, an example of a best

109 Endeavour Energy, Consultation Paper submission, pp. 2-3.

110 Ergon Energy, Consultation Paper submission, pp. 5, 13.

111 ibid.

112 ENA, Consultation Paper submission, p. 7.

113 Ergon Energy, Consultation Paper submission, pp. 13-14.

114 Proposed clause 5.6.2AA(o).

practice non-network proposal, and a worked example of the assessment process, to support existing content.[115]

The Commission also made a number of minor drafting amendments considered to improve and clarify the application of the demand side engagement obligations. These amendments did not affect the principles underlying the proposed rule and are detailed in section 7.2.2 of the draft rule determination.[116]

7.2.2 Stakeholder views - second round of consultation

Demand side engagement document

Energex and Essential Energy considered the requirement to publish the demand side engagement document no later than nine months following commencement of the rule would be problematic given that the RIT-D and RIT-D application guidelines were also due to be published at this time.[117] Given the dependency between the demand side engagement document and the RIT-D, Essential Energy requested clarification be provided as to how the conflicting requirements should be managed. Energex suggested that the rule be amended so that the demand side engagement document be published after the publication of the AER's documentation.[118]

Schedule 5.9 reporting requirements

The Victorian DNSPs and the CEC made a number of suggestions in relation to specific requirements within schedule 5.9.[119] Details of these suggestions, and the Commission's response to each, are set out in Appendix A.

Other comments

The Victorian DNSPs and Ergon Energy noted that they welcomed the Commission's draft decision to remove the requirements in relations to the demand side engagement database.[120] The Victorian DNSPs considered this requirement (among others) would otherwise add significantly to the costs of the annual planning process without delivering material benefit.

115 Draft schedule 5.9(d) and (l).

116 AEMC 2012, *Distribution Network Planning and Expansion Framework*, Rule Determination, AEMC, 14 June 2012, Sydney, p. 50.

117 Energex, Draft Rule Determination submission, p. 9; Essential Energy, Draft Rule Determination submission, p. 2.

118 This issue is addressed in section 11.4 of this final determination.

119 Victorian DNSPs, Draft Rule Determination submission, p. 7; CEC, Draft Rule Determination submission, p. 4.

120 Ergon Energy, Draft Rule Determination submission, p. 3; Victorian DNSPs, Draft Rule Determination submission, p. 2.

7.3 Differences between the draft rule and final rule

Having regard to the views of stakeholders and its own analysis and review, the Commission has largely adopted the draft rules in relation to the demand side engagement obligations, subject to a minor amendment to improve and clarify its application. The manner and reasoning for this amendment is set out below.

7.3.1 Amendments

The Commission has made an additional drafting amendment to improve and clarify the application of the final rule without affecting the principles underlying it. This drafting change is as follows:

- *S5.9(e) regarding content of the demand side engagement document*: the final rule makes a minor drafting amendment to clarify that a demand side engagement document must outline the criteria that will be applied by a DNSP in evaluating non-network proposals.[121]

7.4 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request for the demand side engagement obligations. Outlined below is the Commission's assessment of the final rule, including the reasons why it considers this aspect of the final rule meets the NEO.

7.4.1 Demand side engagement obligations

The demand side engagement strategy as set out in the proposed rule was originally recommended by the AEMC in its Distribution Network Planning and Expansion Review. The strategy was developed in response to concerns from some stakeholders that it can be difficult to engage with DNSPs at an appropriate stage in the planning process, and that there is limited transparency on how DNSPs assess and consider non-network options.[122]

The proposed rule therefore sought to introduce several demand side engagement obligations on DNSPs, including a requirement to develop and document a demand side engagement strategy, and an obligation to engage with non-network providers and consider non-network options in accordance with this strategy. It was considered that these obligations would encourage engagement between DNSPs and non-network providers in the planning and development process and provide the basis for the development of on-going working relationships between these parties.

121 Schedule 5.9(e).

122 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. 15.

The proposed rule also required DNSPs to establish and maintain a facility by which parties may register their interest in being notified of developments relating to distribution network planning. In addition, the proposed rule required DNSPs to develop and maintain a database of proposals and/or case studies that demonstrate the project proposal and assessment process.

In the draft rule determination, the Commission supported the requirement for DNSPs to prepare and publish a document detailing their processes and procedures for assessing non-network options and interacting with non-network providers. The Commission considered that greater transparency and clarity around how DNSPs consider and assess alternatives to network investment should facilitate more efficient planning and investment decisions being made by both non-network providers and DNSPs.

In addition, the Commission expressed support for the requirement to establish a register of interested parties on the basis that this would be an efficient and cost effective method of facilitating information flow between DNSPs and non-network proponents.

However, a number of stakeholders expressed concern that the non-network proposal database may not be the most efficient means of achieving the desired objective. Consequently, the draft rule omitted this obligation and included a new obligation which would require DNSPs to supplement several pieces of key information proposed for inclusion in the demand side engagement document, with examples.[123] This further transparency around DNSPs assessment processes should assist non-network providers (including embedded generators) in developing useful proposals for efficient assessment by DNSPs, without being overly onerous or costly for DNSPs.

Having considered the views of stakeholders in relation to the demand side engagement obligations, the Commission maintains its view set out in the draft rule determination on this matter.

Enhanced engagement

The final rule is one part of the AEMC's broader work program to encourage more timely and meaningful engagement between network business, and consumers and other stakeholders. In addition to the demand side engagement obligations (and annual reporting requirements), our other work to enhance engagement includes:

- the power of choice review, which includes reforms designed to provide consumers with the information, education, incentives and technology they need to efficiently manage their electricity use through greater demand side participation; and

123 DNSPs would be required to review and update these examples (where appropriate), at least once every three years in line with the review of the demand side engagement document.

- the network regulation rule changes, which include proposals to encourage more timely and meaningful consumer engagement as part of the regulatory determination process.

7.5 Rule making test

The Commission is satisfied that the demand side engagement obligations set out in the final rule will, or are likely to, better contribute to the achievement of the NEO than the proposed rule. The final rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity through:

- providing transparency regarding the consideration and assessment of non-network solutions by DNSPs, thereby helping to ensure the efficient provision of non-network solutions by non-network providers; and
- encouraging the engagement of non-network providers in network planning and development which will assist DNSPs in uncovering the full range of efficient investment options, thereby promoting efficient outcomes over time.

8 Joint planning arrangements

This chapter sets out the Commission's views in relation to the joint planning arrangements, having regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 8.1 describes the proposed joint planning arrangements and summarises stakeholder responses to the first round of consultation on this matter;
- section 8.2 describes the joint planning arrangements set out in the draft rule and summarises stakeholder responses to the second round of consultation on this matter;
- section 8.3 sets out the differences between the draft rule and the final rule;
- section 8.4 sets out the Commission's assessment of the final rule in respect of the joint planning arrangements; and
- based on the Commission's assessment in section 8.4, section 8.5 sets out the Commission's conclusions on this matter.

8.1 Proposed rule

8.1.1 Description of the proposed rule

The proposed rule for joint planning contains a number of key elements.[124] These include requiring that:

- each DNSP conduct joint planning with any TNSP which operates a transmission network connected to the DNSP's network;
- the relevant DNSP and TNSP meet on a regular and as required basis to carry out joint planning of their networks over the relevant forward planning period; and
- the relevant DNSP and TNSP use reasonable endeavours to ensure efficient planning outcomes and to identify the most efficient investment options.

In carrying out their joint planning obligations, the DNSPs and TNSPs would be required to:

- identify any system limitations that: (1) will affect both the distribution and transmission networks of the relevant NSPs; or (2) will require coordination by both NSPs to address the system limitation;

124 Joint planning refers to the planning processes and activities undertaken collectively by multiple NSPs to address any common problems which may impact their networks.

- where the need for augmentation or a non-network option is identified, jointly determine plans that can be considered by relevant registered participants, AEMO, interested parties and parties on the demand side engagement register;
- carry out the requirements of the RIT-T for the identified need; and
- agree on a lead party to carry out the requirements of the RIT-T.

The proposed rule also clarifies that DNSPs must meet with each other regularly to undertake joint planning where there is a need to consider any augmentation or non-network option that affects more than one distribution network. It is noted that there are currently no specific provisions in the rules reflecting the joint planning work undertaken between DNSPs.

Current arrangements

The proposed rule is largely consistent with the current requirements for joint planning under clause 5.6.2 of the NER. Aside from providing clarification on several aspects of the existing arrangements, the key change relates to the proposal for the RIT-T to be applied to all joint investments identified through the TNSP-DNSP joint planning process. Currently, two separate tests are applicable to joint planning projects, depending upon the location of a network limitation.[125]

8.1.2 Proponent's view

The proponent considers that the proposed joint planning arrangements (included within the annual planning requirements) would provide greater clarity around the processes for joint planning between DNSPs and TNSPs. This would, in turn, provide for greater efficiency in the development of distribution and transmission networks.

Further, as DNSPs and TNSPs would be required to use the RIT-T to assess any joint network investments and assess a broader range of market benefits, the proponent considers the proposed rule would ensure that the most economically efficient option to address a joint need for investment was identified and adopted.

8.1.3 Stakeholder views - first round of consultation

DNSP-DNSP joint planning obligations

While stakeholders were generally supportive of the proposals to clarify the TNSP-DNSP joint planning arrangements, Aurora Energy did not consider that the proposed rule was sufficiently clear in respect of the arrangements for DNSP-DNSP joint planning.[126] Energex also requested clarification in relation to which DNSP would be

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125 Under existing arrangements, the RIT-T would be applied to joint planning projects driven by the need to address a limitation on a transmission network, while the regulatory test would be applied to projects driven by the need to address an issue on a distribution network.

126 Aurora Energy, Consultation Paper submission, p. 7.

required to undertake a RIT-D where there was a multitude of network owners involved in a single project.[127]

Project assessment process for joint planning projects

In submissions to the consultation paper, stakeholders expressed considerable concern in relation to the proposal for the RIT-T to be applied to all network investment projects identified through the joint planning process.

The ENA considered that, in the majority of cases, investment resulting from the joint planning process would not have a material market effect. The ENA considered that a material market effect would only ever likely occur where joint planning lead to reinforcement of the interconnected transmission network either to: (1) ensure a distribution network met the minimum power system security and reliability standards; or (2) replace distribution assets.[128]

The ENA and Ausgrid considered the RIT-T should only be performed where the preferred solution to address a distribution limitation was a transmission solution; where the preferred solution to address a distribution limitation was a distribution solution (even where a transmission solution may be an option), the RIT-D should be performed.[129]

Energex did not support the RIT-T being undertaken in all circumstances where expenditure on a transmission network was required. It considered a more practical alternative would be for the RIT-T to be undertaken only where there was a material increase in transmission capacity (the RIT-D would be undertaken where there is a material increase in the distribution network).[130]

Further, the ENA and ETSA Utilities queried whether a TNSP or DNSP would be required to perform the RIT-T where an investment was required to address a distribution limitation.[131] The ENA was of the view that TNSPs should always be the lead party where the RIT-T project assessment process was required. It considered this was appropriate on the basis that DNSPs would not be equipped, nor have sufficient resources, to undertake the RIT-T in addition to the RIT-D.[132] More generally, ETSA Utilities considered further clarity was required in the rule as to when each test (the RIT-T or RIT-D) would need to be performed and by which party (a TNSP or DNSP).[133]

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127 Energex, Consultation Paper submission, p. 6.

128 ENA, Consultation Paper submission, p. 10.

129 ENA, Consultation Paper submission, p. 10; Ausgrid, Consultation Paper submission, p. 5.

130 Energex, Consultation Paper submission, p. 5.

131 ENA, Consultation Paper submission, pp. 4, 9-10, 20; ETSA Utilities, Consultation Paper submission, p. 5.

132 ENA, Consultation Paper submission, pp. 4, 9-10, 20.

133 ETSA Utilities, Consultation Paper submission, p. 6.

Treatment of dual function assets

Ausgrid considered clarification was required in respect of the AEMC's policy intent regarding the treatment of dual function assets in the context of joint planning. It noted that this issue was of particular concern to Ausgrid, given it is both a TNSP and DNSP for the purpose of Chapter 5, owns and operates dual function assets and undertakes detailed joint planning both internally as TNSP and DNSP, and as a TNSP and DNSP with TransGrid.[134]

8.2 Draft rule

8.2.1 Description of the draft rule

The draft rule largely adopted the proposed rule in relation to the joint planning arrangements as described above, subject to a modification considered to improve its application and better promote the NEO. The modification made to the proposed rule was as follows:

- *Project assessment process for joint planning projects*: the draft rule differed from the proposed rule in respect of the circumstances in which NSPs would be required to apply the RIT-T to projects identified through the joint planning process. The draft rule required that the RIT-T be undertaken for joint planning projects in circumstances where at least one potential credible option[135] contained a network or non-network option on a transmission network with an estimated capital cost greater than $5 million. In other cases, NSPs would have the option of undertaking the RIT-D process as an alternative to the RIT-T process (where the relevant criteria were met).

The Commission also made a number of minor drafting amendments considered to improve and clarify the application of the joint planning arrangements. These amendments did not affect the principles underlying the proposed rule and are detailed in 8.2.2 of the draft rule determination.[136]

8.2.2 Stakeholder views - second round of consultation

Project assessment process for joint planning projects

In their submissions to the draft rule determination, the ENA, Ergon Energy and Energex suggested that the rule be amended to specify that a TNSP be deemed the lead

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134 Ausgrid, Consultation Paper submission, p. 5.

135 'Potential credible option' was included as a new local definition in the draft rule. It refers to an investment option which a RIT-T proponent or a RIT-D proponent (as the case may be) reasonably considers has the potential to be a credible option based on its initial assessment of the identified need. See chapter 9 for further discussion on this term.

136 AEMC 2012, *Distribution Network Planning and Expansion Framework*, Rule Determination, AEMC, 14 June 2012, Sydney, pp. 58-59.

party responsible for carrying out the RIT-T, unless otherwise agreed between parties.[137]

The ENA considered that DNSPs would experience significant implementation and ongoing costs if required to complete a RIT-T for all joint planning projects, even where a project involves minimal transmission investment.[138] The ENA considered that the requirement for DNSPs to implement and maintain compliance with not only the RIT-D but also the RIT-T was an additional cost not borne by TNSPs.

Ergon Energy maintained its view that DNSPs should not be responsible for carrying out the RIT-T.[139] It noted that the RIT-T and RIT-D differed in a number of respects meaning that DNSPs would not be equipped nor have sufficient resources to undertake both tests. While Energex acknowledged the AEMC's attempt to address the regulatory burden on DNSPs, it did not support DNSPs being required to undertake a RIT-T due to the additional costs that would be incurred. Energex noted that while the RIT-T and RIT-D were similar, each test would require different processes, systems and skill sets.[140]

Essential Energy considered the assessment process for joint planning should be determined by the nature of the issue being resolved (for example, the RIT-D where there is a distribution issue; the RIT-T where there is a transmission issue).[141] It considered a realistic approach would be to base the responsibility for project carriage on the nature of the constraint being addressed and the materiality of transmission impact and involvement. In addition, Essential Energy considered that a $5 million limit was not an effective proxy for the true nature of project responsibility.

Other comments

The Victorian DNSPs considered the draft rule created an inconsistent approach to the operation of the cost threshold to joint planning projects, depending on whether they are subject to the RIT-T or the RIT-D. The Victorian DNSPs proposed that the draft rule be amended so that the RIT-D only apply to joint planning projects where there is an option which includes investment on the network of the lead DNSP which is greater than $5 million. The Victorian DNSPs considered this would be consistent with the treatment of joint planning projects under the RIT-T.[142]

In relation to clause 5.14.1(b), the Victorian DNSPs also stated that they did not understand how or why an interested party should be involved in the joint planning of

137 ENA, Draft Rule Determination submission, p. 1; Ergon Energy, Draft Rule Determination submission, p. 5; Energex, Draft Rule Determination submission, pp. 2, 13.

138 ENA, Draft Rule Determination submission, p. 1.

139 Ergon Energy, Draft Rule Determination submission, p. 5.

140 Energex, Draft Rule Determination submission, pp. 2, 13.

141 Essential Energy, Draft Rule Determination submission, p. 2.

142 Victorian DNSPs, Draft Rule Determination submission, p. 5.

a declared shared network. These DNSPs were not aware of any reason why the Commission considers this proposal would promote the NEO.[143]

8.3 Differences between the draft rule and final rule

Having regard to the views of stakeholders and its own analysis and review, the Commission has largely adopted the draft rules in relation to the joint planning arrangements, subject to a number of further minor amendments to improve and clarify its application. The manner and reasoning for these amendments are set out below.

8.3.1 Amendments

The Commission has made a number of additional drafting amendments to improve and clarify the application of the final rule without affecting the principles underlying it. These drafting changes are as follows:

- *Definition of transmission-distribution connection points*: the final rule clarifies that, in relation to the declared transmission system of an adoptive jurisdiction, a transmission-distribution connection point is defined as the agreed point of supply between the transmission assets of the declared transmission system operator and a distribution network.[144]

- *Projects subject to the RIT-T and RIT-D*: the final rule clarifies that only those connection assets which provide services other than prescribed transmission services or standard control services would be exempt from the RIT-T and the RIT-D.[145]

- *Criterion for determining the project assessment process to apply to a joint planning project*: the final rule clarifies that the criterion for determining the appropriate project assessment process to apply to a joint planning project is directly linked to the level of the RIT-T cost threshold. Reference to “$5 million” in the definition of "RIT-T project" has been replaced with a reference to the cost threshold specified under clause 5.16.3(a)(2).[146]

- *TNSP-DNSP and DNSP-DNSP joint planning obligations*: the final rule removes the specific obligation for DNSPs and TNSPs, and DNSPs with each other, to “meet regularly and as required” as part of their joint planning obligations. The focus of the obligations under clause 5.14.1(d)(1) and 5.14.2(a) are for DNSPs and TNSPs, and DNSPs with each other, to undertake joint planning.

143 Victorian DNSPs, Draft Rule Determination submission, p. 6.

144 Clause 5.10.2 (local definition of “transmission-distribution connection point”).

145 Clause 5.16.3(a)(6) and 5.17.3(a)(4).

146 Clause 5.10.2 (local definition of "RIT-T project").

- *Other minor changes*: to reflect comments made in submissions to the draft rule determination, the final rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details on these amendments.

8.4 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request for the joint planning arrangements. Outlined below is the Commission's assessment of the final rule, including the reasons why it considers this aspect of the final rule meets the NEO.

8.4.1 TNSP-DNSP joint planning obligations

The proposed rule set out arrangements for joint planning which would apply to each DNSP with the TNSP of the transmission networks to which the DNSPs' network is connected. The proposed arrangements recognised that the current processes adopted by TNSPs and DNSPs in carrying out joint planning activities appeared to be working effectively. The purpose was therefore to clearly reflect current practices in the rules and to balance the obligations currently imposed on TNSPs in respect of joint planning with corresponding obligations on DNSPs.[147]

In the draft rule determination, the Commission considered that the proposed arrangements would promote the efficient operation of networks by subjecting DNSPs and TNSPs to a clearly defined and efficient joint planning process. This would allow parties to jointly identify, and begin the process of addressing, potential issues affecting multiple networks, in a timely manner.

Noting that stakeholders did not comment on this aspect of the draft rule in submissions to the draft rule determination, the Commission maintains its view set out in the draft rule determination on this matter.

Notwithstanding the above, the final rule includes a minor amendment to provide DNSPs and TNSPs with the flexibility to determine between themselves how best to meet their joint planning obligations. The requirement to “meet regularly and as required” has been omitted from clause 5.14.1(d)(1).

8.4.2 DNSP-DNSP joint planning obligations

The proposed rule included a general provision which clarified that, where it was necessary to consider the need for network or non-network investment which may

147 Currently, the NER requires TNSPs to be the lead party in conducting joint planning with DNSPs. The draft rule seeks to balance this provision by placing an obligation on DNSPs to conduct joint planning with TNSPs and vice versa.

affect multiple distribution networks, DNSPs would be required to meet regularly and as required to undertake joint planning with other DNSPs.[148]

In submissions to the consultation paper, a number of stakeholders suggested further clarification be provided in the draft rule in relation to certain aspects of DNSP-DNSP joint planning activities. In light of the arguments put forward in submissions, the draft rule included an additional provision which clarified that DNSPs would be expected to agree on a lead party for carrying out the requirements of the RIT-D where there are multiple DNSPs involved in a single project.

In the draft rule determination, the Commission noted that while the DNSP-DNSP joint planning obligations were less prescriptive than the equivalent arrangements for TNSP-DNSP joint planning, this was appropriate on the basis that the degree of interaction required between DNSPs, and the complexity of issues DNSPs face, can vary significantly across jurisdictions. The Commission therefore considered it appropriate that the rules retain some flexibility in respect of the DNSP-DNSP joint planning procedures.

Noting that stakeholders did not comment on this aspect of the draft rule in submissions to the draft rule determination, the Commission maintains its view set out in the draft rule determination on this matter.

Consistent with the minor amendment made to the TNSP-DNSP joint planning obligations, the requirement to "meet regularly and as required" has been omitted from clause 5.14.2(a). This amendment provides DNSPs with the flexibility to determine between themselves how best to meet their joint planning obligations.

8.4.3 Project assessment process for joint planning projects

Applicable regulatory investment test

The proposed rule sought to require that the RIT-T be applied to all joint planning projects irrespective of the location of a system limitation (that is, whether it is identified on a distribution network or transmission network) or the balance of investment between a transmission network and a distribution network.

In submissions to the consultation paper, several DNSPs raised a concern in relation to the application of the RIT-T to projects involving minimal transmission investment, undertaken to address limitations on a distribution network. The key concern (as understood by the Commission) was that, in these cases, outcomes of the joint planning process would be unlikely to have a material market impact and hence would be unlikely to deliver material market benefits. Undertaking a project assessment and consultation process designed specifically to capture material market benefits may therefore impose a regulatory burden on the relevant NSPs, with minimal potential benefit.

148 As noted, there are currently no specific provisions in the NER reflecting the joint planning work undertaken between DNSPs.

To address this concern, the draft rule provided NSPs with the option of applying the RIT-D (rather than the RIT-T) project assessment process in instances where the opportunities for the delivery of material market benefits may be limited. This circumstance was proxied by use of the RIT-T cost threshold level, currently set at $5 million.[149] Where none of the potential credible options to address a system limitation contained a network or non-network option on a transmission network with an estimated capital cost greater than $5 million (or any other amount as varied by the RIT-T cost threshold review), NSPs would have the option of progressing the RIT-D project assessment process as an alternative to the RIT-T project assessment process.

By providing some flexibility in the approach to assessing joint planning projects, the Commission considered that the draft rule would achieve an appropriate balance between the regulatory burden placed on NSPs in conducting the RIT-T, and the need to ensure that those joint planning projects likely to deliver material market benefits are subject to a robust and comprehensive project assessment process.

Having considered the arguments and evidence put forward in submissions to the draft rule determination in relation to the project assessment process for joint planning projects, the Commission maintains its view set out in the draft rule determination.

In general, a single project assessment and consultation process should be applied to all joint planning projects, irrespective of the location of a system limitation. This approach will result in all joint planning projects being subject to an equally transparent project assessment process, robust cost benefit assessment and comprehensive consultation process.

In addition, the Commission considers that the RIT-T process, rather than the RIT-D, is the appropriate process to apply to joint planning projects, as the general rule. Given that joint planning projects will, by definition, affect both a transmission network and a distribution network, the quantification of market benefits would be a key factor in a joint planning project's broader assessment to identify the most economic investment option. On the basis that the RIT-T mandates the quantification of material market benefits, application of the RIT-T to joint planning projects would lead to any applicable market benefits being appropriately considered and quantified.

Lead party to apply the applicable regulatory investment test

The proposed rule provided for parties undertaking joint planning to agree on a lead party responsible for carrying out the requirements of the RIT-T.[150]

In its submission to the consultation paper, the ENA did not consider that it was appropriate to require DNSPs to carry out the requirements of the RIT-T on the basis

149 As noted in section 8.3.1, for clarity, reference to the $5 million threshold has been replaced in the final rule with a reference to the RIT-T cost threshold. See clause 5.10.2 (local definition of "RIT-T project").

150 Where a lead party is agreed, the other parties would be deemed to have discharged their obligations to undertake the relevant regulatory investment test for the particular joint planning project.

that DNSPs would not be equipped nor have sufficient resources to do so. The ENA considered that TNSPs should always be the lead party in the instances a RIT-T assessment was required.[151]

While the Commission acknowledged this concern, it did not agree with the suggestion that TNSPs should always be the lead party when carrying out the requirements of the RIT-T. In the draft rule determination, the Commission noted that while the proposed rule provided for the relevant TNSP and DNSP to agree on a party to lead the relevant regulatory investment test process, the selection of a lead party did not preclude the other parties' participation in the assessment process. This arrangement would allow parties to allocate the work required for the RIT-T project assessment process among themselves, in light of the particulars of the matter in hand.

In addition, the Commission noted that the arrangements would require that the relevant NSPs work together to meet the necessary regulatory requirements with the aim of identifying the most efficient investment options to address limitations and constraints identified on NSPs networks.[152] In instances where a DNSP was identified as the lead party for carrying out the requirements of the RIT-T, the relevant TNSP should work closely with that DNSP in carrying out the requirements of the RIT-T, including providing input into any market benefits assessment.

Having considered the arguments and evidence put forward in submissions to the draft rule determination in relation to the lead party for the project assessment process, the Commission maintains its view set out in the draft rule determination on this matter.

Several DNSPs suggested that the rule be amended to deem TNSPs the lead party to carry out the requirements of the RIT-T unless otherwise agreed by the parties.[153] However, the Commission does not consider it appropriate for the rule to allocate responsibility to one party over another on the basis that each NSP should retain control over the planning of the network which it operates. In addition, while it may be more efficient in some instances for a TNSP to lead the RIT-T project assessment process, the rules provide flexibility for DNSPs to be the lead party where this is appropriate. As noted above, the selection of a lead party does not preclude participation by the other parties in the relevant project assessment process. Further, it is difficult to envisage a TNSP not wishing to cooperate to ensure efficient planning outcomes, particularly where a project is deemed likely to have a significant impact on the TNSP or its network.

151 ENA, Consultation Paper submission, p. 10.

152 As noted previously, the draft rule requires the relevant TNSPs and DNSPs to use best endeavours to work together to achieve efficient planning outcomes and identify the most efficient options to address the needs identified.

153 ENA, Draft Rule Determination submission, p. 1; Ergon Energy, Draft Rule Determination submission, p. 5; Energex, Draft Rule Determination submission, pp. 2, 13.

8.4.4 Treatment of dual function assets

As noted in section 5.4.2, the proposed rule did not propose to change the current approach to the treatment of dual function assets in the context of network planning and expansion. However, the draft rule made a number of minor amendments to ensure the joint planning arrangements were clear and workable for dual function assets.

No specific comments were received from stakeholders in submissions to the draft rule determination in respect of the treatment of dual function assets in the context of the joint planning arrangements. The final rule is therefore consistent with the arrangements in the draft rule. A brief summary is provided below.

TNSP- DNSP joint planning obligations

The joint planning arrangements set out in clause 5.14.1 are intended to apply to each DNSP with the TNSP of the transmission networks to which the DNSP's network is connected and vice versa. On the basis that dual function assets predominately form part of a network that is a distribution network,[154] these requirements are not intended to apply to DNSPs with TNSPs who are registered within the same organisation for the purposes of owning, controlling or operating dual function assets. In other words, these arrangements are not intended to prescribe the process for joint planning to be carried out internally by a DNSP in relation to the distribution assets and dual function assets which form its distribution network. This is intent is clarified in the final rule.[155]

For the avoidance of doubt, a DNSP's 'distribution network' in this clause includes distribution assets and any dual function assets which the DNSP owns and operates. Therefore, in carrying out joint planning with a TNSP of a transmission network to which the DNSP's network is connected, a DNSP must plan (as relevant) having regard to its distribution assets and any dual function assets which may also form part of its distribution network.

Applicable regulatory investment test

As noted in section 5.4.2, dual function assets will continue to be treated in the same manner as distribution assets for the purposes of the project assessment process. Therefore, consistent with the discussion above, joint planning projects which include the possibility of expenditure on dual function assets will be subject to assessment under the RIT-T in all cases where at least one potential credible option to address an identified need contains a network or non-network option on a transmission network (other than dual function assets) with an estimated capital cost greater than $5 million.

154 See the definition of 'dual function asset' in NER Chapter 10.

155 Clause 5.14.1(c).

8.4.5 Consequential amendments to the RIT-T rules

The final rules relating to joint planning require that a number of consequential changes be made to the rules in relation to the RIT-T (including to the RIT-T dispute resolution process).[156] These changes are not intended to alter the application of the RIT-T to projects other than joint planning projects. Rather, the changes are intended to facilitate integration of the joint planning provisions (including new definitions) into the existing rules and, in doing so, improve readability of the final rule relative to the proposed rule. The key changes are as follows:

- references to "transmission network service provider or distribution network service provider (as the case may be)" have been removed and replaced, where relevant, with references to "RIT-T proponent";
- references to "transmission investment or joint network investment (as the case may be)" have been removed and replaced with references to "RIT-T project" or, where relevant, to "network investment";
- NER clauses 5.6.5C(a)(6) and (7) have been omitted on the basis that the application of the RIT-T to dual function assets has been clarified in clause 5.17.3(b);
- NER clauses 5.6.5C(a)(4), (8) and (9) have been amended to ensure the provisions are capable of being applied in the joint planning context;[157] and
- other amendments to the format and location of clauses defining credible options and setting out the cost threshold determination process.

By using consistent language throughout the Chapter 5 Part B (where appropriate), the non-material changes set out above will promote clarity of meaning and improve the overall readability of the rules.

8.5 Rule making test

The Commission is satisfied that the joint planning arrangements set out in the final rule will, or are likely to, better contribute to the achievement of the NEO than the proposed rule. The final rule is likely to promote efficient investment in electricity networks for the long term interests of consumers of electricity through:

- providing greater clarity around the processes for joint planning between DNSPs and TNSPs, and between DNSPs, thereby promoting efficiency in the development of distribution and transmission networks; and

156 See clauses 5.15 and 5.16 of the final rule. The proposed rule also included a number of consequential changes to the RIT-T rules. See proposed clauses 5.6.5B, 5.6.5C, 5.6.5D, 5.6.5 E, 5.6.6, 5.6.6A and 5.6.6AA.

157 Clauses 5.16.3(a)(4), (6)-(7).

- improving consistency and transparency of joint planning project assessments, thereby promoting more efficient decision making by NSPs.

In addition, by providing some flexibility in the approach to assessing joint planning projects, the final rule achieves an appropriate balance between the regulatory burden placed on NSPs in carrying out the project assessment and consultation process, and the need to subject joint planning projects to an appropriately robust and comprehensive project assessment process given the nature of the investment options.

9 Regulatory investment test for distribution

This chapter sets out the Commission's views in relation to the RIT-D, having regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 9.1 describes the proposed RIT-D arrangements and summarises stakeholder responses to the first round of consultation on this matter;
- section 9.2 describes the RIT-D arrangements set out in the draft rule and summarises stakeholder responses to the second round of consultation on this matter;
- section 9.3 sets out the differences between the draft rule and the final rule;
- section 9.4 sets out the Commission's assessment of the final rule in respect of the RIT-D; and
- based on the Commission's assessment in section 9.4, section 9.5 sets out the Commission's conclusions on this matter.

9.1 Proposed rule

9.1.1 Description of the proposed rule

The purpose of establishing the RIT-D process is to provide a framework for DNSPs to consider a range of potential options to address the investment needs of the network.[158] Under the proposed rule, the RIT-D process would be relevant where a need to invest in the distribution network has been identified and the estimated capital cost of the most expensive option to address the relevant identified need which is technically and economically feasible is $5 million or more.

Through the RIT-D process, a DNSP would be able to identify a technology-neutral credible option that maximises the net present value of economic benefits. In the case where the identified need is for reliability corrective action, it is possible that a preferred option may have a negative net economic benefit (that is, a net economic cost).

The RIT-D process would not apply to investments which relate to: urgent or unforeseen network issues; negotiated, alternative control and unclassified services; replacement and refurbishment expenditure; connection assets; or where the proposed investment has been identified through joint planning processes between DNSPs and TNSPs.

158 MCE, Rule Change Request, 30 March 2011, p. 4.

The proposed rule also specifies that the RIT-D must:

- be based on a cost-benefit analysis of reasonable scenarios for each credible option compared to the scenario where no option is implemented;
- include a level of analysis that is proportionate to the scale and potential impact of the credible options;
- be applied in a predictable, transparent and consistent manner; and
- include consideration of potential market benefits.

Under the proposed rule, the AER would be required to develop and publish RIT-D application guidelines which are reflective of these principles. The guidelines would also be consistent with the RIT-D process proposed to be outlined in the NER. The RIT-D process would include the following stages:

- *An initial screening test* (the 'specification threshold test' or 'STT') to determine the appropriate RIT-D consultation and reporting requirements. Projects which meet the requirements of the STT would proceed to the project specification stage. All other projects would proceed directly to the project assessment stage.[159]
- *A project specification stage* where DNSPs would be required to consult on alternative proposals to meet the identified need before the project assessment stage. The recommended period for consultation would be four months.
- *A project assessment stage* involving consideration of applicable market benefits and costs for each credible option to determine the preferred option. DNSPs would be required to quantify all applicable costs, but would have the option to decide whether market benefits should be included. This information is to be set out by the DNSP in a final project assessment report.

In order to determine if non-network options have been duly considered, the proposed rule would also provide the AER with specific powers to:

- review a DNSP's policies and procedures to determine if non-network options have been duly considered; and
- audit projects which have been identified by DNSPs as not meeting the RIT-D threshold.

159 Under proposed clauses 5.6.6AB(c)-(e), DNSPs would be required to undertake a specification threshold test to assess: (1) the reasons for a proposed distribution investment, including the assumptions used in identifying the identified need; and (2) technically feasible non-network options that could either defer or remove the need for a proposed distribution investments to address the identified need. If, after undertaking the STT, a DNSP determined that there were no technically feasible non-network options to either defer or remove the need for a proposed distribution investment to address the identified need, the DNSP would not be required to publish a project specification report under proposed clause 5.6.6AB(g).

Under the proposed rule, the AER would also be required to publish a report by 31 March each year setting out the results of any audits undertaken over the previous 12 months.

The proposed rule also included discrete proposals for the introduction of a dispute resolution process. These proposals are dealt with separately in Chapter 10 of this final determination.

Current arrangements

The current rules require DNSPs to carry out an economic cost effectiveness test for any distribution network investment project to identify potential investment options that satisfy the regulatory test.[160] The term 'cost effectiveness test' is used in the NER to refer to the reliability limb of the regulatory test whereby the lowest cost option of meeting a reliability obligation would be selected. Currently, the NER does not accommodate the assessment of market benefits for different investment options under this limb.[161]

For distribution projects with a capital cost above $10 million, the NER also requires DNSPs to consult on their economic cost effectiveness analysis and publish a report on the results of the cost effectiveness test.[162] Several jurisdictions also have in place additional requirements on DNSPs in respect of case-by-case project assessments and consultation, and project evaluations.[163]

It is intended that the new RIT-D process would replace the existing regulatory test requirements set out in the NER and any supplementary jurisdictional arrangements.

9.1.2 Proponent's view

The rule change request states that the RIT-D process has been designed to ensure that DNSPs consider investment options in a transparent, consultative and technologically neutral manner. In doing so, the process is intended to facilitate the discovery and adoption of the most economically efficient investment option to address an identified need. The proponent considers that the process would increase efficiency in the

160 Since the commencement of the NEM, there has been a requirement to assess the economic contribution or feasibility of network augmentation investment proposals by means of a 'regulatory test', the form of which has varied over time. The regulatory test can be applied differently, depending on the primary purpose of the prospective investment. There are two possible limbs: (1) a reliability limb; and (2) a market benefits limb. For further information see www.aer.gov.au.

161 As such, the rules assume that all DNSP augmentations are driven by reliability obligations, which may not the case.

162 The NER does not require DNSPs to consult in relation to the economic assessment of projects, nor explain their decisions in respect of investments, under $10 million.

163 Both New South Wales and South Australia (SA) require a case-by-case project assessment of all proposed augmentations to evaluate the possibility of non-network solutions. In addition, only these two states specify an evaluation process that distributors should follow in considering projects. See AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Scoping and Issues Paper, 12 March 2009, Sydney, p. 20.

development and operation of distribution networks, and potentially provide for more efficient network charges and improved reliability for consumers of electricity.[164]

In addition, the proponent considers that clearer and more comprehensive information regarding DNSPs' decision making processes would assist other market participants such as TNSPs, connection applicants and non-network providers to make more efficient investment decisions when operating in the NEM. Detailed information regarding the economic justification of distribution investments may also assist the AER in its determination of DNSPs' revenues under Chapter 6 of the NER which should result in more efficient network charges.[165]

9.1.3 Stakeholder views - first round of consultation

In submissions to the consultation paper, stakeholders raised a significant number of issues in relation to the proposed RIT-D. Several key themes emerged, specifically in relation to: the scope of the RIT-D (particularly the approach to applying the RIT-D cost threshold and the types of investments subject to the RIT-D); the operation of the specification threshold test; and the provision of specific review and audit powers for the AER. A summary of the key issues is set out below.

RIT-D cost threshold

A number of stakeholders expressed concern in relation to the application of the RIT-D cost threshold to the most expensive option which is technically and economically feasible.[166] Specifically, the ENA, Ergon Energy and Energex considered this approach would create a regulatory burden on DNSPs on the basis that:

- the term 'economically and technically' feasible could be broadly interpreted, thus increasing the likelihood of the most expensive option for investment being above $5 million; and
- such terminology would essentially require DNSPs to undertake a preliminary 'mini least cost regulatory investment test' prior to undertaking the specification threshold test.[167]

Stakeholders proposed a number of alternative approaches to applying the RIT-D cost threshold. For example, the ENA and Energex suggested the focus of the requirement be on the 'least expensive option'.[168] This was supported by Ergon Energy who

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164 MCE, Rule Change Request, 30 March 2011.

165 ibid.

166 ENA, Consultation Paper submission, pp. 4, 13, 15; Ergon Energy, Consultation Paper submission, pp. 4-5; Energex, Consultation Paper submission, pp. 9, 15; Victorian DNSPs, Consultation Paper submission, pp. 5, 16; ETSA Utilities, Consultation Paper submission, pp. 6-8.

167 ENA, Consultation Paper submission, pp. 4, 13, 5; Ergon Energy, Consultation Paper submission, pp. 4-5; Energex, Consultation Paper submission, pp. 9, 15.

168 ENA, Consultation Paper submission, pp. 4, 13, 15; Energex, Consultation Paper submission, pp. 9, 15.

considered that either the 'least expensive option' or, alternatively, the 'preferred option', should be the focus.[169] ETSA Utilities and the Victorian DNSPs considered the threshold should be set with reference to the capital cost of the 'preferred network investment option'.[170] In addition, Essential Energy considered the provision would more meaningfully relate to the 'credible option' definition and use.[171]

In relation to the RIT-D cost threshold level, the AER expressed support for the $5 million figure on the basis that it provided consistency with the RIT-T and was sufficiently high that it would not create a significant RIT-D assessment burden on DNSPs.[172]

In contrast, the ENA, Endeavour Energy and the Victorian DNSPs questioned whether the $5 million cost threshold level was appropriate.[173] Endeavour Energy considered $5 million was too low and requested further consultation on the matter. The Victorian DNSPs considered the threshold should be no lower than $5 million.

Overall, Ergon Energy considered the RIT-D design parameters were an improvement on current arrangements and consistent with the NEO.[174]

Projects subject to the RIT-D

A number of stakeholders suggested several other classes of distribution investments should be excluded from assessment under the RIT-D.[175] In addition, a number of stakeholders requested clarity on whether the RIT-D would be required in certain circumstances.[176]

In relation to the exclusion of investments required to address urgent and unforeseen network issues, several stakeholders considered the timeframe of six months in the definition of 'urgent or unforeseen network issue'[177] was unrealistic given the lead times required for procurement of equipment, design and construction.[178] As a more reasonable alternative, these stakeholders suggested amending the timeframe to

169 Ergon Energy, Consultation Paper submission, pp. 4-5.

170 Victorian DNSPs, Consultation Paper submission, pp. 5, 16; ETSA Utilities, Consultation Paper submission, pp. 6-8.

171 Essential Energy, Consultation Paper submission, p. 7.

172 AER, Consultation Paper submission, p. 6.

173 ENA, Consultation Paper submission, p.15; Endeavour Energy, Consultation Paper submission, pp. 6-8; Victorian DNSPs, Consultation Paper submission, pp. 5, 16.

174 Ergon Energy, Consultation Paper submission, p. 9.

175 ENA, Consultation Paper submission, p. 16; Ergon Energy, Consultation Paper submission, pp. 5, 17; ETSA Utilities, Consultation Paper submission, pp.6-8.

176 Energex, Consultation Paper submission, pp. 7, 10, 18; Ergon Energy, Consultation Paper submission, p. 15; ETSA Utilities, Consultation Paper submission, pp. 6-8; ENA, Consultation Paper submission, p. 15; Ausgrid, Consultation Paper submission, pp. 6-8.

177 Proposed clause 5.6.5CB(c).

178 ENA, Consultation Paper submission, p. 16; Ergon Energy, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 5; Essential Energy, Consultation Paper submission, p. 7; ETSA Utilities, Consultation Paper submission, pp. 6-8.

between 12 and 24 months.[179] Ergon Energy also suggested amending the terminology from 'required to be operational' to 'required to be commenced'.[180] The ENA considered that rather than prescribe a more appropriate timeframe, urgent and unforeseen work should fall within the exemptions framework.[181]

In contrast, the AER suggested it would be rare for a distribution project greater than $5 million to be urgent or unforeseen. On this basis, the AER was supportive of the proposed limitations on exemptions from the RIT-D for urgent and unforeseen projects. It considered these provisions would ensure that DNSPs could not exclude projects from assessment under the RIT-D process due to errors or deficiencies in a DNSPs own planning arrangements. The AER also considered that these provisions would restrict any "gaming opportunities" for a DNSP to delay project planning to avoid the RIT-D assessment process.[182]

Specification threshold test

While the majority of stakeholders appeared to support the purpose of the STT, several stakeholders considered that the proposed drafting required clarification as to which projects were intended to be streamlined through the RIT-D process.[183]

Specifically, several stakeholders considered the phrase 'technically feasible' was problematic and would result in DNSPs never being able to identify those projects originally intended to be streamlined through the RIT-D process, thereby rendering the STT ineffective.[184] As an alternative, the ENA and Energex suggested that 'technically feasible non-network options' be amended to 'credible non-network options' on the basis that this change would necessitate non-network options being both commercially and technically feasible, and able to be completed in a timely manner.[185] Ergon Energy considered this provision should be drafted to limit the number of assessments to only those proposals which could potentially be implemented.[186]

In addition, Ausgrid requested the inclusion of a more refined criteria than 'technically feasible' in order to determine when consultation on non-network options was considered appropriate. Ausgrid suggested guidance could be taken from the NSW Demand Management Code of Practice for Electrical Distribution.[187]

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179 Ergon Energy, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 5; Essential Energy, Consultation Paper submission, p. 7; ETSA Utilities, Consultation Paper submission, pp. 6-8.

180 Ergon Energy, Consultation Paper submission, p. 18.

181 ENA, Consultation Paper submission, p. 16.

182 AER, Consultation Paper submission, p. 8.

183 ENA, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 2.

184 ENA, Consultation Paper submission, p. 18; Energex, Consultation Paper submission, p. 13; ETSA Utilities, Consultation Paper submission, pp. 6-8.

185 ENA, Consultation Paper submission, p. 18; Energex, Consultation Paper submission, p. 13.

186 Ergon Energy, Consultation Paper submission, p. 21.

187 Ausgrid, Consultation Paper submission, p. 3.

AER review and audit activities

The majority of DNSPs did not support the proposal to provide the AER with specific review and audit powers in relation to DNSPs consideration of non-network options, noting that these activities would be captured by the AER's existing functions and powers set out in legislation in relation to monitoring, investigating and enforcing compliance.[188] Specifically, Energex was opposed to this requirement on the basis that the framework in which DNSPs identify and determine these projects is already examined by the AER as part of the regulatory determination process.[189] Endeavour Energy considered the AER's existing powers of review through the dispute resolution process were appropriate and sufficient.[190] Ergon Energy considered the prima facie position should be that a DNSP’s policies and procedures are fully compliant with the rules and the prerequisite should be that the AER has valid reason for reviewing a DNSP’s policies and procedures.[191] In contrast, the AER, TEC and EnerNOC supported these proposals.[192]

In respect of the proposal requiring the AER to publish an annual audit report, a number of stakeholders considered that there was not sufficient justification for a separate report to be published. Instead, the results of any audits could be included in the quarterly compliance reports currently published by the AER.[193] The AER also considered that it was not clear why this obligation was necessary given that it is the enforcement body for the NEM and publishes quarterly compliance reports and investigative reports on its enforcement and compliance activities.[194] The AER suggested that the proposal be drafted as an option rather than an obligation.

In contrast, Aurora Energy and EnerNOC supported of the requirement that the AER must publish an annual report detailing the results of any audits undertaken in the last 12 months.[195]

Reapplication of the RIT-D

Energex suggested that the AEMC clarify the circumstances in which a DNSP would be expected to reapply the RIT-D.[196] In its supplementary submission, Energex noted

188 Ergon Energy, Consultation Paper submission, p. 19; Energex, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 16; Ausgrid, Consultation Paper submission, pp. 6-8; Endeavour Energy, Consultation Paper submission, p. 9; Essential Energy, Consultation Paper submission, p. 7; Aurora Energy, Consultation Paper submission, p. 8.

189 Energex, Consultation Paper submission, p. 18.

190 Endeavour Energy, Consultation Paper submission, p. 9.

191 Ergon Energy, Consultation Paper submission, p. 19.

192 AER, Consultation Paper submission, p. 8; TEC, Consultation Paper submission, p. 5; EnerNOC, Consultation Paper submission, p. 6.

193 Ergon Energy, Consultation Paper submission, pp. 9-10; Energex, Consultation Paper submission, p. 19; Victorian DNSPs, Consultation Paper submission, p. 16; Endeavour Energy, Consultation Paper submission, p. 9; Essential Energy, Consultation Paper submission, p. 7.

194 AER, Consultation Paper submission, p. 8.

195 Aurora Energy, Consultation Paper submission, p. 8; EnerNOC, Consultation Paper submission, p. 6.

that the issue of the reapplication of the RIT-D was primarily driven by uncertainty around the relationship between conducting a RIT-D and then building an option to address the identified limitation.[197] Energex considered that DNSPs should not be required to undertake multiple RIT-D assessments in relation to the same network limitations in instances where circumstances may change between a RIT-D assessment and commencement of construction.

In addition, the AER considered that further thought should be given to whether DNSPs should be required to reapply the RIT-D in certain circumstances, including where a significant period of time has elapsed since completion of an original assessment.[198]

General comments

The ENA expressed concern that the overall complexity of the proposed RIT-D process would introduce unacceptable delays in the provision of electricity network infrastructure which may become the subject of compliance and enforcement disputes.[199]

The AER also expressed concern in respect of the proposed approach to setting out the principles underpinning the RIT-D. The AER noted that its preference would be for the rules to set out high level principles regarding the coverage of the RIT-D, with further details on the nature of the test and classes of costs and benefits to be set out in the RIT-D application guidelines.[200]

More generally, Aurora Energy noted that it did not support the introduction of the RIT-D on the basis that it appeared to be addressing a "perceived" rather than an "actual" failure. Aurora Energy considered that the RIT-D would be more administratively onerous than the current regulatory test, and that the changes proposed to allow for preferred non-network solutions could lead to issues in respect of reliability and security of supply.[201]

9.2 Draft rule

9.2.1 Description of the draft rule

The draft rule largely adopted the proposed rule in relation to the RIT-D as described above, subject to several modifications considered to improve their application and better promote the NEO. The modifications made to the proposed rule were as follows:

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196 Energex, Consultation Paper supplementary submission, p. 3.

197 ibid.

198 AER, Consultation Paper submission, pp. 6-7.

199 ENA, Consultation Paper submission, p. 4.

200 AER, Consultation Paper submission, pp. 4-6.

201 Aurora Energy, Consultation Paper submission, p. 7.

- *Specification threshold test*: the draft rule made several changes to the concept of the STT (under the heading 'non-network screening process'). Specifically, the draft rule provided for a RIT-D proponent[202] to discharge its obligation to prepare and publish a 'non-network options report' (previously the 'project specification report') where it determines that there will not be a non-network option that is a potential credible option to address an identified need.[203]

- *Project specification report*: the draft rule made several changes to the project specification report (renamed the 'non-network options report') so that it was focussed on: (1) providing relevant information to non-network providers to assist them in considering, developing and proposing viable non-network options; and (2) seeking information from interested stakeholders on non-network options that are potential credible options, including on the range of materially relevant market benefits and costs.[204]

- *Reapplication of the RIT-D in certain circumstances*: the draft rule included a new provision which clarified that, unless otherwise determined by the AER, a RIT-D proponent must reapply the RIT-D where there is a material change in circumstances which, in the reasonable opinion of the RIT-D proponent, means the preferred option identified in the original RIT-D assessment is no longer a preferred option.[205]

- *AER review and audit activities*: the draft rule did not include additional powers for the AER to review and audit a DNSP's activities regarding the consideration of non-network options.[206]

- *Additional classes of market benefits*: the draft rule removed the ability for a DNSP to consider any other class of market benefit it considered to be relevant when carrying out a RIT-D project assessment. However, the draft rule included a new obligation on a RIT-D proponent to consider any other class of market benefit (or financial cost) determined to be relevant by the AER.[207]

The Commission also made a number of minor drafting amendments considered to improve and clarify the application of the RIT-D rules. These amendments did not affect the principles underlying the proposed rule and are detailed in section 9.2.2 of the draft rule determination.[208]

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202 'RIT-D proponent' is included as a new definition in the draft rule. It clarifies that, in light of the joint planning arrangements, a DNSP or a TNSP may carry out the requirements of the RIT-D where the relevant criteria are met. See Chapter 8 for further discussion of this definition.

203 Proposed clauses 5.6.6AB(c)-(e) and draft clauses 5.17.4(b)-(d).

204 Proposed clause 5.6.6(h) and draft clause 5.17.4(e).

205 Draft clauses 5.17.4(t) and (u).

206 Proposed clauses 5.6.5CB(f)-(h).

207 Proposed clause 5.6.5CA(4)(viii) and draft clause 5.17.1(4)(viii).

208 AEMC 2012, *Distribution Network Planning and Expansion Framework*, Rule Determination, 14 June 2012, Sydney, pp. 77-78.

9.2.2 Stakeholder views - second round of consultation

In submissions to the draft rule determination, stakeholders raised a several issues in relation to the draft RIT-D rules. The key issues are summarised below.[209]

RIT-D principles

The AER expressed concern in relation to the level of discretion afforded to DNSPs in deciding whether or not to quantify market benefits during a RIT-D assessment.[210] The AER considered that the approach taken in the draft rule may be a violation of the principle that the RIT-D be capable of being applied in a predictable and consistent manner. It suggested that the draft rule be amended to require the mandatory quantification of all market benefits determined to be material or which would alter the selection of the preferred option.

The ENA, Energex, Ergon Energy and the Victorian DNSPs requested clarification from the AEMC that the quantification of market benefits would be optional under the RIT-D.[211] The ENA also considered that the decision on whether or not to quantify market benefits should not be subject to the dispute resolution process.

Ergon Energy, the Victorian DNSPs and Energex also suggested that the RIT-D principles be amended to include a statement that the RIT-D does not require DNSPs to undertake network investment.[212] The Victorian DNSPs also considered a similar principle should also be stated in respect of the RIT-T.

RIT-D cost threshold

A number of stakeholders reiterated their concern in relation to the proposed application of the RIT-D cost threshold to the 'most expensive' potential credible option.

The ENA considered that DNSPs would experience significant implementation and ongoing costs associated with applying the threshold to the 'most expensive' option on the basis that this would capture all but the smallest projects.[213] It considered that this would be inconsistent with the intention of having a cost threshold that attempts to address "the current disproportionate regulatory burden on DNSPs". The ENA noted that if the intention was to provide adequate incentive on DNSPs to comply with the rules, then the existing AER compliance mechanisms should be relied on as the most cost-effective.

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209 Appendix A provides details all the issues raised in submissions, including the Commission's response.

210 AER, Draft Rule Determination, p. 4.

211 ENA, Draft Rule Determination submission, p. 2; Energex, Draft Rule Determination submission, pp. 16-17; Ergon Energy, Draft Rule Determination submission, p. 5; Victorian DNSPs, Draft Rule Determination submission, p. 17.

212 Ergon Energy, Draft Rule Determination submission, p. 4; Energex, Draft Rule Determination submission, pp. 22-23; Victorian DNSPs, Draft Rule Determination submission, p. 8.

213 ENA, Draft Rule Determination submission, p. 2.

The Victorian DNSPs considered that the $5 million threshold level would only be appropriate if applied to the 'preferred project'.[214] These stakeholders considered this approach would: (1) better ensure that the costs of conducting the RIT-D did not exceed the likely benefits for a particular project; and (2) would avoid creating a situation whereby NSPs were discouraged from considering more expensive capital projects so that the RIT-D was not inadvertently triggered.

Ergon Energy and Energex expressed a number of concerns in relation to the application of the RIT-D cost threshold to the most expensive potential credible option. First, these stakeholders considered reference to potential 'credible' option was problematic on the basis that it would require DNSPs to undertake an net present value (NPV) analysis (or mini regulatory investment test) in order to determine whether an option was commercially feasible.[215] Energex noted that it was unaware of any proper test for determining commercial feasibility which would not involve an assessment of costs and benefits.

Second, these stakeholders had significant concerns in relation to the requirement to apply the cost threshold level to the 'most expensive' option, particularly given DNSPs would be unlikely to build the 'most expensive' option. Ergon Energy considered it was unclear why this term had been adopted and suggested the AEMC reconsider using the term 'least expensive' option. Energex also reiterated its support for amending the approach to refer to ‘least cost’ option on the basis that this would significantly reduce compliance costs for DNSPs by avoiding unnecessary RIT-D assessments. Energex noted that, unless the approach was amended, it would be required to conduct a RIT-D for significantly more projects than what was conducted in 2012.

Energex also considered that if the threshold test was intended to be a ’desktop exercise’, then a provision to this effect should be included in the rules (for example, a rule stating that only readily available material should be used).[216]

Projects subject to the RIT-D

Several stakeholders expressed concern in relation to the definition of 'urgent and unforeseen network issue' set out in the draft rule.[217] The Victorian DNSPs considered the requirement for projects which were ‘reasonably foreseeable’ to be subject to the RIT-D would penalise customers by exposing them to unacceptable reliability issues where an urgent need was not foreseen by the DNSP. The Victorian DNSPs suggested the rule be amended such that the definition of urgent problems does not relate to the foreseeability of the project need.

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214 Victorian DNSPs, Draft Rule Determination submission, pp. 8, 9-12.

215 Ergon Energy, Draft Rule Determination submission, p. 4; Energex, Draft Rule Determination submission, pp. 2, 17-19.

216 Energex, Draft Rule Determination submission, pp. 2, 17-19.

217 Victorian DNSPs, Draft Rule Determination submission, pp. 8, 12.

Energex suggested an additional subclause be added to what would be deemed urgent and unforeseen so that it captures those projects which are required to be implemented to meet a reliability standard that would otherwise be breached if the project was subject to the RIT-D process.[218]

Ergon Energy reiterated its view that the requirement for a project to be 'operational' would not be workable in practice (given the majority of investments will take longer than six months to be operational). In addition, this would not capture projects that would need to commence earlier than the time taken to complete the RIT-D process to ensure reliability and system criteria were met. It requested the AEMC re-examine this issue.[219]

Screening for non-network options

Energex considered that it was unclear whether the notice required to be published under draft clause 5.17.4(d) was for information purposes only.[220] It expressed concern that third parties may raise an issue with the notice under the misapprehension that it is published for consultative purposes. Energex suggested that the AEMC consider amending the rules so that it is clear the notice is for information purposes only.[221]

The AER expressed concern that the RIT-D procedures encouraged RIT-D proponents to only look at pure non-network or network options and not options which combine both types of investment.[222] It considered the rule should be clarified to state that a RIT-D proponent should look at whether a non-network option is a potential credible option or can form part of a potential credible option.

In addition, the AER noted that, as drafted, the screening process may not ensure an adequate assessment of non-network options on the basis that DNSPs were not required to consult prior to making a determination.[223] It also expressed concern that the demand side engagement obligations may not ensure DNSPs adequately engage with non-network proponents early in the planning process. The AER proposed that if a RIT-D proponent concludes that a non-network option is not a potential credible option, then, in addition to publishing their finding, they must notify all non-network providers on their register of the conclusion and then allow one month for submissions on that conclusion.

Non-network options report

The ENA and Ergon Energy considered the required minimum four month consultation period on the non-network options report was too long and

218 Energex, Draft Rule Determination submission, p. 24.

219 Ergon Energy, Draft Rule Determination submission, p. 9.

220 Energex, Draft Rule Determination submission, p. 21.

221 Energex was also concerned that the RIT- D process diagram set out in the draft rule determination did not reflect the process set out in the draft rules. This issue is addressed in Appendix A.

222 AER, Draft Rule Determination submission, p. 5.

223 AER, Draft Rule Determination submission, pp. 4-5.

disproportionate to other consultation periods in the NER.[224] The ENA considered that DNSPs would experience significant implementation and ongoing costs from delays resulting from the protracted RIT-D assessment and dispute timeframes. Ergon Energy suggested that the rule be amended to allow RIT-D proponents to adopt a staged consultation approach to the non-network options report (if desired). It considered this would enable DNSPs to manage their risk by minimising the information they are required to prepare in the first instance.

While the Victorian DNSPs concurred with the Commission that draft rule provides a better method for streamlining the RIT-D where non-network options are not credible, they also considered the proposed four month consultation period was excessive. The Victorian DNSPs suggested 30 business days would be an appropriate consultation period.[225]

Reapplication of the RIT-D

Ergon Energy and Energex both questioned whether a DNSPs decision to reapply the RIT-D would be subject to the dispute resolution process.[226] These stakeholders considered the rules already provided the AER with sufficient power to independently review a DNSPs reapplication assessment as part of its monitoring and enforcement role of the NER.

Energex also suggested that reapplication of the RIT-D not be required where a project is urgent or where the additional delay caused by any reapplication would result in the DNSP being unable to meet its reliability standards.[227]

The AER supported the inclusion of a provision requiring the reapplication of the RIT-D.[228] However, it suggested that where a material change in circumstance is a delay in the identified need (for example, due to a change in the demand forecast), DNSPs should be required to wait until the identified need arises again before reapplying the RIT-D. This would ensure that the new assessment would consider any new credible options which have arisen since the first application of the RIT-D.

Ergon Energy sought the AEMC's view on what may constitute a 'material change'. It questioned whether, for example, a material change would occur only when there was a major change in the scope of the RIT-D project.[229]

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224 ENA, Draft Rule Determination submission, p. 2; Ergon Energy, Draft Rule Determination submission, pp. 4-5.

225 Victorian DNSPs, Draft Rule Determination submission, p. 13.

226 Ergon Energy, Draft Rule Determination submission, p. 5; Energex, Draft Rule Determination submission, p. 22.

227 Energex, Draft Rule Determination submission, p. 22.

228 AER, Draft Rule Determination submission, p. 5.

229 Ergon Energy, Draft Rule Determination submission, p. 9.

Publication of the final project assessment report

The AER considered the $20 million threshold which would determine whether a RIT-D proponent could discharge its obligation to publish a separate final project assessment report, may be too high.[230] It considered that distribution projects above $10 million tend to be major projects and should be subject to their own final report. Consequently, a more appropriate threshold would be $10 million.

RIT-T rules

In respect of the investments which would be exempt from the RIT-T, the Victorian DNSPs expressed concern that transmission-distribution connection points were excluded from the RIT-T without good cause.[231] They considered that a regulatory investment test should be applied to transmission-distribution connection decisions.

9.3 Differences between the draft rule and final rule

Having regard to the views of stakeholders and its own analysis and review, the Commission has largely adopted the draft rules in relation to the RIT-D, subject to a number of minor drafting amendments to improve and clarify its application. The manner and reasoning for these amendments is set out below.

9.3.1 Amendments

The Commission has made a number of additional amendments to improve and clarify the application of the final rule without affecting the principles underlying it. These changes are as follows:

- *Screening for non-network options*: the final rule makes a number of minor amendments to clarify that a RIT-D proponent is not required to prepare and publish a non-network options report if it determines "on reasonable grounds" that there will not be a non-network option that is a potential credible option, "or forms a significant part of a potential credible option", for the RIT-D project to address the identified need.[232]

- *Non-network options report period of consultation*: the final rule has amended the minimum period of time DNSPs are required to provide relevant stakeholders to make submissions on the non-network options report. The timeframe has been reduced from four months to three months.[233]

- *Reapplication of the RIT-D in certain circumstances*: the final rule clarifies that a material change in circumstances may include, but is not limited to, a change to the key assumptions used in identifying: (1) the identified need described in the

230 AER, Draft Rule Determination submission, p. 5

231 Victorian DNSP, Draft Rule Determination submission, pp. 6, 9.

232 Clause 5.17.4(c).

233 Clause 5.17.4(h).

final project assessment report; or (2) the credible options assessed in the final project assessment report.[234] The final rule also clarifies that, in determining whether a RIT-D proponent does not need to reapply the RIT-D in accordance with clause 5.17.4(t), the AER must have regard to (among other things) whether the RIT-D project is required to address a network issue that, if not addressed, is likely to materially adversely affect the reliability and secure operating state of the distribution network, or a significant part of that network.[235]

- *RIT-D application guidelines*: the final rule expands the scope of matters to be included in the RIT-D application guidelines to require the AER to provide guidance on what will be considered to be "a material and adverse national electricity market impact" for the purposes of the definition of interested parties in clause 5.15.1.[236]
- *Other minor changes*: to reflect comments made in submissions to the draft rule determination, the final rule includes a number of other minor drafting amendments. The policy issues log set out in Appendix A, and the legal issues log set out in Appendix B, provide further details on these amendments.

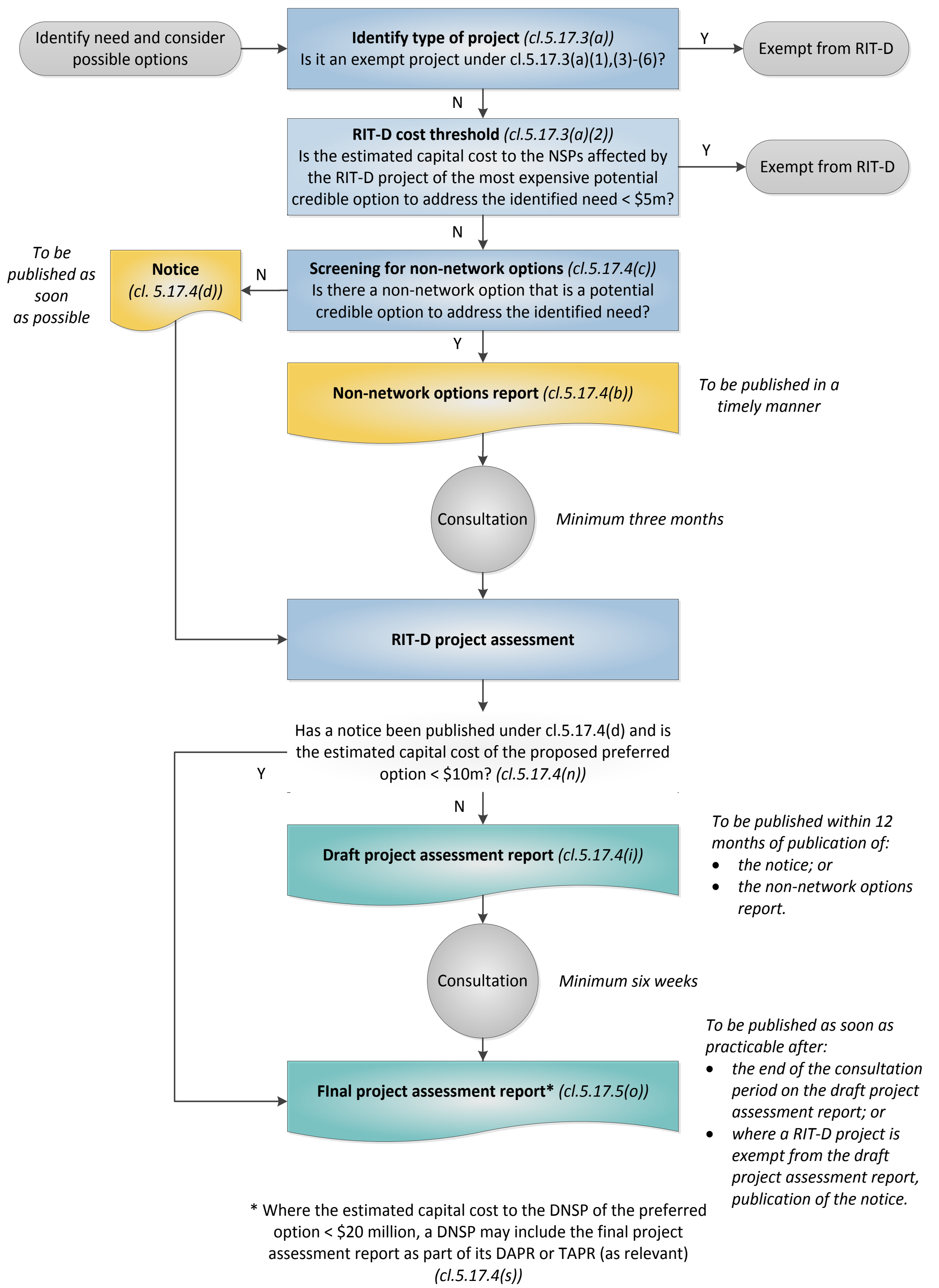
A summary of the RIT-D process is set out in figure 9.1 below.

234 Clause 5.17.4(u).

235 Clause 5.17.4(v).

236 Clause 5.17.2(b)(2)(iii).

Figure 9.1 RIT-D process



9.4 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request for the RIT-D. Outlined below is the Commission's assessment of the final rule, including the reasons why it considers this aspect of the final rule meets the NEO.

9.4.1 RIT-D principles

Amalgamation of the reliability and market benefits limbs

The proposed rule set out a design for the RIT-D which amalgamated the reliability and market benefits limbs of the current regulatory test into a single cost-benefit framework. All projects for which the RIT-D is applicable would be assessed under this framework.

In the draft rule determination, the Commission noted that there were significant advantages in having a single cost-benefit framework process that could be applied consistently across all prospective projects, irrespective of the driver for the investment. Importantly, the single process would allow all projects to be assessed against local reliability standards as well as against their ability to maximise benefits to the broader market. This would help DNSPs in identifying the most efficient investment option, rather than simply the least-cost investment option, to address a network issue. The Commission considered this would facilitate efficient decision making by NSPs and promote efficient investment in networks.

In submissions to the draft rule determination, stakeholders did not raise any specific issues in respect of the introduction of a single cost-benefit framework. The Commission therefore maintains its view set out in the draft rule determination on this matter.

Assessment of market benefits and costs

The RIT-D principles specified in the proposed rule required that DNSPs consider all applicable market benefits and costs for each credible option when applying the RIT-D. However, while DNSPs would be required to quantify all applicable costs, they would have the option of quantifying any applicable market benefits.

In the draft rule determination, the Commission considered that allowing some flexibility in the assessment of market benefits under the RIT-D was appropriate on the basis that, in many cases, RIT-D projects would tend to have limited market benefits. This design would help in establishing a project assessment process that was fit for purpose for each RIT-D project.

In its submission to the draft rule determination, the AER expressed concern that allowing the optional quantification of market benefits may violate the principle which states that the RIT-D must be capable of being applied in a predictable and consistent manner.[237] The AER suggested the draft rule be amended to require the mandatory quantification of all market benefits determined to be material or which would alter the selection of the preferred option.[238]

In addition to the principle that the RIT-D be capable of being applied in a predictable, transparent and consistent manner, the NER also requires that the RIT-D must not require a level of analysis that is disproportionate to the scale and likely impact of each of the credible options being considered.[239] There are inevitable tensions between some of the RIT-D principles. It is therefore important that the final rule strikes an appropriate balance between them.

Having considered the AER's submission in detail, the Commission is satisfied that an optional approach to the assessment of market benefits is appropriate. Having regard to the general characteristics of distribution investments, the final rule will help to balance the regulatory burden on the RIT-D proponent from carrying out the RIT-D with the potential benefits of the assessment process.

In submissions to the draft rule determination, several stakeholders also requested that the AEMC provide clarification that the quantification of market benefits would be optional under the RIT-D.

Clause 5.17.1(d) of the final rule states that:

> "(d) A RIT-D proponent may, under the *regulatory investment test for distribution*, quantify each class of market benefits under paragraph (c)(4) where the RIT-D proponent considers that:
>
> (1) any applicable market benefits may be material; or
>
> (2) the quantification of market benefits may alter the selection of the preferred option."

The Commission confirms that it is the intention of clause 5.17.1(d) that the quantification of market benefits is optional under the RIT-D. However, this clause must be read in conjunction with clause 5.17.1(b) which states that:

> "(b) ...For the avoidance of doubt, a preferred option may, in the relevant circumstance, have a negative net economic benefit (that is, a net economic cost) where an identified need is for reliability corrective action."

Therefore, where an identified need is not for reliability corrective action, a RIT-D proponent would need to quantify both the applicable costs and market benefits associated with each credible option in order for the preferred option to have a positive

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237 Clause 5.17.1(c)(3).

238 AER, Draft Rule Determination, p. 4.

239 Clause 5.17.1(c)(2).

net economic benefit. On this basis, the quantification of market benefits under the RIT-D would be optional for reliability driven projects only.

9.4.2 Projects subject to the RIT-D

RIT-D cost threshold

The purpose of the RIT-D cost threshold is to balance the administrative burden on RIT-D proponents conducting the RIT-D process with the potential benefits. It achieves this by providing a dollar amount below which the RIT-D would not be applied.

The proposed rule provided for the cost threshold level to be applied to the most expensive option which is both technically and economically feasible. The terms 'technically and economically feasible' were originally included in the RIT-T rules to clarify that the RIT-T cost threshold would not be expected to be applied to potential options which are not comparable in cost to other potential options to address an identified need. In effect, this qualification would avoid the RIT-T process being triggered by a potential investment option which, based on its estimated cost, would be unlikely to be identified as a preferred option in the RIT-T assessment.

In submissions to the draft rule determination, a number of stakeholders expressed concern that the terms 'technically and economically feasible' were open to interpretation and, in line with the concerns raised by Grid Australia in the context of the RIT-T,[240] would lead to almost every project being subject to the RIT-D.[241] These stakeholders suggested amending the approach to applying the RIT-D cost threshold to the least expensive technically feasible option or, alternatively, to a DNSPs preferred option.

In the draft rule determination, the Commission stated that while further clarification regarding the application of the RIT-D cost threshold may be beneficial, for a number of reasons it did not consider that amending the rule in the manner suggested by stakeholders was the best means of addressing their concerns.

First, changing the approach to applying the RIT-D cost threshold (for example, from 'most expensive' option to 'least expensive' option) would require reconsideration of whether the $5 million cost threshold level remained appropriate. The Commission's preference was not to change the proposed RIT-D settings on the basis that application of the $5 million cost threshold level to the most expensive potential credible option would subject the appropriate range of projects to a robust economic assessment without imposing an unreasonable burden on DNSPs in respect of the timing and resources required to conduct the process.

240 AEMC 2008, *National Transmission Planning Arrangements*, Draft Report, 2 May 2008, Sydney, p. 37.

241 ENA, Consultation Paper submission, pp. 4, 13, 15; Ergon Energy, Consultation Paper submission, pp. 4-5; Energex, Consultation Paper submission, pp. 9, 15; Victorian DNSPs, Consultation Paper submission, pp. 5, 16; ETSA Utilities, Consultation Paper submission, pp. 6-8.

Second, the concerns raised by stakeholders were a direct consequence of the interpretation of the terminology used in the proposed rule, rather than a fundamental issue with the RIT-D cost threshold settings themselves. On this basis, the Commission proposed a change to the terminology used to describe the approach to applying the RIT-D cost threshold with the aim of better clarifying the intent. Specifically, reference to 'the most expensive option which is technically and economically feasible' was replaced with reference to 'the most expensive potential credible option'.

The Commission considered it would be more meaningful to relate the RIT-D cost threshold to the subset of potential options to which the RIT-D must be applied (that is, to the group of potential 'credible options' as defined under section 5.15.2 of the draft rule). It also clarified that an extremely high cost option which would be unlikely to deliver materially higher market benefits compared to other potential options would not be expected to be included in the list of potential options to which the RIT-D cost threshold level would be applied.

In addition, the term 'potential' was included to recognise that at this stage in the RIT-D process, a RIT-D proponent would not have carried out the necessary analysis to enable it to have fully formed a view on which options were ‘credible options’ for the purpose of assessment under the RIT-D. However, a RIT-D proponent would be expected to have formed at least an initial view on the possibility of potential options being both technically and commercially feasible, and likely to be implemented in a timely manner. It is to this initial list of potential credible options that the RIT-D cost threshold should be applied.

In submissions to the draft rule determination, a number of stakeholders continued to express concern in relation to the application of the RIT-D cost threshold to the most expensive potential credible option.[242] However, having considered these concerns in detail, the Commission remains of the view that the RIT-D cost threshold as set out in the draft rule is appropriate. In making this decision, the Commission notes:

- The RIT-T rules include equivalent provisions in respect of the RIT-T cost threshold and these provisions have proved to be workable in practice. The RIT-T application guidelines include guidance on what constitutes a credible option, and the number and range of credible options a TNSP would reasonably be expected to consider in undertaking the RIT-T. In addition, the RIT-T application guidelines provide both guidance and examples on what would constitute 'commercially feasible' and 'technically feasible' options. Equivalent guidance will be provided by the AER in the RIT-D application guidelines. [243]

242 These concerns are set out in detail in section 9.2.2 and Appendix A of this determination.

243 In the draft rule determination, we concluded that the terms "commercially feasible" and "economically feasible" were interchangeable expressions in the context within which they were used in the proposed rule. We recognise that these terms may have different meanings and interpretations outside of their use in the RIT-T (and RIT-D). It is for this reason that the AER included guidance in the RIT-T application guidelines as to the meaning of these terms in this specific context. We expect that equivalent guidance will be provided by the AER in the RIT-D application guidelines.

- The trigger for consultation and assessment under the current regulatory test makes reference to the preferred network option identified by DNSPs. The current trigger and its link to network options has the potential to cause bias and therefore act as a barrier to non-network options being given due consideration in the project assessment process. This is because applying the threshold to the preferred (or most likely) network option risks creating a situation where that option becomes the benchmark for assessment, rather than any other credible option that may address an identified need. Applying the threshold to the most expensive option will expand the scope of the RIT-D relative to the current regulatory test, and help to facilitate a neutral assessment of both network and non-network options.

- Applying the RIT-D cost threshold to the most expensive potential credible option will not result in anomalous outcomes, nor have possible unintended consequences if it is applied as intended. As noted in the draft rule determination, it is not intended that the RIT-D be triggered by potential options which are not comparable in cost to other potential options identified to address a specific network issue (the exception to this being where it is expected that an option is likely to deliver materially higher market benefits). Further clarification on the application of the RIT-D cost threshold is a matter to be addressed by the AER in the RIT-D application guidelines as required under clause 5.17.2.

- As noted previously, the Commission is satisfied that application of the $5 million cost threshold to the most expensive potential credible option will subject the appropriate range of projects to a robust and transparent economic assessment. The RIT-D procedures include a number of mechanisms carefully designed to help minimise the regulatory burden placed on DNSPs in carrying out the RIT-D process.[244]

Projects subject to the RIT-D

While it is intended that the RIT-D be applied to all projects involving expenditure in respect of a network, there are several types of projects which would be exempt from the RIT-D. As noted in section 9.1.1, these include projects which relate to: urgent or unforeseen network issues; negotiated, alternative control and unclassified services; replacements and refurbishment expenditure; and connection assets.

In the draft rule determination, the Commission considered it appropriate to exempt these projects from the scope of the RIT-D on the basis that the benefits to be gained from their assessment under the RIT-D would, in most cases, be unlikely to outweigh the costs, risks or regulatory burden on relevant NSPs from applying the RIT-D process. For example, including replacement and refurbishment expenditure within the scope of the RIT-D may impose a disproportionate regulatory burden on DNSPs due to the large volume of replacements undertaken by DNSPs and the limited

244 These include the ability for a RIT-D proponent to be exempt from the obligations to publish: (1) a non-network options report in accordance with clause 5.17.4(c); and (2) a draft project assessment report in accordance with clause 5.17.4(n).

alternatives for replacement investments. The Commission considered that to require NSPs to apply the RIT-D in these circumstances would represent an unnecessary regulatory burden, particularly as public consultation and reporting on the assessment of replacement investments would be unlikely to yield alternative solutions which may be more efficient.

In submissions to the consultation paper, a number of stakeholders advocated for the exclusion of several other classes of distribution projects from the scope of RIT-D. Several stakeholders also requested clarification as to whether other certain types of investment projects would or would not be considered to be within the scope of the RIT-D.[245] The Commission's response to each issue was set out in Appendix A of the draft rule determination.[246]

For the purposes of clarification, the Commission notes that DNSPs (and TNSPs where a TNSP has been identified as the lead party for a RIT-D project) would be required to apply the RIT-D to all projects which meet the following criteria:

- the driver for the investment is the need to address an issue on a distribution network (or a transmission network if the need is identified under the joint planning process); and
- the expenditure will be made by an NSP; and
- the expenditure will be (fully or partially) recovered from all users of the network; and
- the RIT-D project meets the RIT-D cost threshold.

Exemptions would then be provided for:

- RIT-D projects required to address an urgent and unforeseen network issue;
- RIT-D projects related to the replacement and refurbishment of assets (except where that investment includes an augmentation to the network with an estimated capital cost greater than $5 million); and
- projects where the identified need is identified through the joint planning process and to which the RIT-T is applicable.

The Commission notes that it is not the intention to include in the rules an exhaustive list of all circumstances in which the RIT-D would apply. Apart from the 'criteria' listed above, further clarification could be included in the AER guidelines if the AER and stakeholders consider that may be helpful.

245 Energex, Consultation Paper submission, pp. 7, 10, 18; Ergon Energy, Consultation Paper submission, pp. 15-16; ETSA Utilities, Consultation Paper submission, pp. 6-8; ENA, Consultation Paper submission, p. 15; Ausgrid, Consultation Paper submission, pp. 6-8.

246 AEMC 2012, *Distribution Network Planning and Expansion Framework*, Rule Determination, 14 June 2012, Sydney, pp. 160-165.

Urgent and unforeseen network issues

The proposed rule provided an exemption from the RIT-D for projects required to address an urgent and unforseen network issue. Under the proposed rule, a distribution investment would be considered to address an urgent and unforeseen network issue if:

- it was necessary that the proposed distribution investment be operational within six months of the NSP identifying the identified need; and
- the event or circumstances causing the identified need was not reasonably foreseeable by, and was beyond the reasonable control of, the DNSP; and
- a failure to address the identified need would be likely to materially adversely affect the reliability and secure operating state of the distribution network.

In submissions to the consultation paper, several stakeholders expressed concern in relation to the requirement for an investment to be operational within six months of a network issue being identified, in order to qualify for the exemption.[247] While the Commission acknowledged this concern in the draft rule determination, it considered that the definition of urgent and unforeseen network issue was appropriate given the circumstances and types of projects intended to be captured by the provision.[248] In addition, the exemption was intended to be used rarely and only where the need for investment resulted from unanticipated and extenuating circumstances such as extreme weather: it was not intended that the exemption be used by DNSPs in the place of accurate and timely planning practices.

However, in submissions to the draft rule determination, the Victoria DNSPs, Energex and Ergon Energy continued to express concern with certain aspects of the definition of urgent and unforeseen network issue.[249] Having considered these issues in detail, the Commission remains of the view that the definition of 'urgent and unforeseen' network issue is appropriate for the reasons explained in the draft rule determination.

Further, in response to a concern raised by the Victorian DNSPs, we note that projects required to address urgent network issues that would otherwise put at risk the reliability of the distribution network but which could have been reasonably foreseen by a DNSP, should not be exempt from the RIT-D. It is important that DNSPs have strong incentives to undertake comprehensive planning and to deliver appropriate levels of network reliability to meet consumers' needs.

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247 ENA, Consultation Paper submission, p. 16; Ergon Energy, Consultation Paper submission, p. 18; Victorian DNSPs, Consultation Paper submission, p. 5; Essential Energy, Consultation Paper submission, p. 7; ETSA Utilities, Consultation Paper submission, pp. 6-8.

248 This was subject to several minor drafting amendments to the terminology to recognise the requirements of the joint planning process.

249 These concerns are set out in detail in section 9.2.2 and Appendix A of this determination.

9.4.3 RIT-D procedures

Screening for non-network options

In establishing a project assessment process which was fit for purpose and proportionate to its potential benefits, the proposed rule introduced a screening process (the 'specification threshold test') designed to tailor the consultation and reporting requirements to each RIT-D project. The test, carried out prior to commencement of the RIT-D, required DNSPs to assess:

- the reasons for a proposed distribution investment, including the assumptions used in identifying the identified need; and
- technically feasible non-network options that could either defer or remove the need for a proposed distribution investments to address the identified need.

If, after undertaking the specification threshold test, a DNSP determined that there were no technically feasible non-network options to either defer or remove the need for a proposed distribution investment to address an identified need, the DNSP would be exempt from the requirement to publish a project specification report. The DNSP would, however, be required to make available on its website a specification threshold test report. The purpose of this report would be to outline its assessment and the methodologies and assumptions used to make this assessment.

In submissions to the consultation paper, a number of stakeholders expressed concern that the drafting of the proposed rule failed to capture the original intent of the initial screening test. Specifically, these stakeholders were concerned that the requirement to assess 'technically feasible' non-network options would result in all distribution projects meeting the screening test criteria, therefore rendering it ineffective as a means of providing flexibility in the RIT-D process.[250] As an alternative, these stakeholders suggested that the phrase 'technically feasible non-network options' be replaced with reference to 'credible non-network options'. In effect, this change would provide for the streamlining of the RIT-D process for projects where, following the screening test assessment, a DNSP was unable to identify a credible non-network option (that is, a non-network option which was commercially and technically feasible and able to be implemented in a timely manner).

Having regard to stakeholder views, the Commission noted that linking the screening process to 'credible non-network options' would allow RIT-D proponents to draw on any information gathered through earlier engagement with non-network providers on the technical and commercial feasibility, and timeliness, of particular non-network options. This would enable them to take a more informed view on the material potential for non-network solutions and should encourage RIT-D proponents to engage with non-network providers earlier in the process and on an ongoing basis.

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250 This is because it would always be possible to identify at least one 'technically feasible' non-network option (irrespective of whether a technically feasible option was commercially and/or economically feasible).

The draft rule therefore redesigned the concept of the specification threshold test to provide an exemption from the requirements to prepare and publish a non-network options report (previously the 'project specification report'), where a RIT-D proponent determined that there would not be a non-network option which was a potential credible option to address the identified need. Where a RIT-D proponent made such a determination (based on the information available to it at the time), it would not be required to consult with interested stakeholders to investigate potential non-network options further.

The Commission considered this change would provide for a more targeted screening process to identify those projects where there was the material potential for non-network options as an alternative to network investment.

In its submission to the draft rule determination, the AER considered that the screening process as drafted may not ensure an adequate assessment of non-network options on the basis that DNSPs were not required to consult prior to making a determination. The AER proposed that if a RIT-D proponent concluded that a non-network option was not a potential credible option, then, in addition to publishing its finding, it must notify all non-network providers on the register of the conclusion and then allow one month for submissions on that conclusion.[251]

The Commission has considered this issue in detail but considers that the design of the non-network options screening test will only provide exemptions from the requirement to prepare and publish a non-network options report in limited circumstances – that is, where a RIT-D proponent has reasonable grounds to determine that a non-network option will not be a potential credible option.[252]

To make this clear, a minor amendment has been made to clause 5.17.4(c) to require that a DNSP must determine "on reasonable grounds" that there will not be a non-network option that is a potential credible option to address an identified need. Where a DNSP does not have reasonable grounds to make such a determination, it would be required to prepare and publish a non-network options report.[253]

To clarify, the notice required to be published under clause 5.17.4(d) is intended for information purposes only.

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251 AER, Draft Rule Determination submission, pp. 4-5.

252 In most cases, this provision will provide for the streamlining of projects where the nature of the identified need does not accommodate a non-network solution. However, the process also provides for the streamlining of projects where a DNSP has reasonable grounds to determine that, while an identified need may be able to accommodate a non-network solution, there are no technically and/or commercially feasible non-network options available to address the identified need. This possibility should provide an incentive for DNSPs to engage with non-network providers earlier in the process and on an ongoing basis.

253 Clause 5.17.4(c) also includes an additional amendment to recognise that a non-network option may form all, or a significant part of, a potential credible option. This change is specified in section 9.3.1.

Non-network options report

Under the proposed rule, investments which met the requirements of the specification threshold test would be subject to consultation through the publication of a project specification report. The purpose of this report was to consult publicly on the range of options (network and non-network) to meet the identified need, and seek comments on any alternative options.

In the draft rule determination, the Commission made several changes to the content of the project specification report (renamed the non-network options report) to focus it on:

1. providing information to non-network proponents to assist them in considering, developing and proposing viable non-network options; and

2. seeking information from interested stakeholders on potential credible options, including on the range of materially relevant costs and market benefits.

For the report to be useful and meet these objectives, the Commission considered it would need to provide relevant information that would be of assistance to market participants and interested parties, including non-network proponents, in preparing useful and informative non-network proposals and/or submissions.

On this basis, the draft rule set out the key information required to be included in the non-network options report. This included: a description of the identified need; the relevant annual deferred augmentation charge associated with the identified need; the technical characteristics that a non-network option would be required to meet; and a summary of potential non-network options which may address the identified need, as identified by the RIT-D proponent.

The Commission noted that the draft rule did not prevent relevant NSPs from providing additional information to, or requesting additional information from, stakeholders, where additional information may assist NSPs in their application of the RIT-D.[254]

In submissions to the draft rule determination, stakeholders did not provide specific comments on the required content of the non-network options report.. The Commission therefore maintains its view that the non-network options report will, by promoting greater consultation with relevant stakeholders, assist RIT-D proponents to identify potential non-network options and be better informed on the costs and market benefits associated with a potential investment option. This process should reduce the

254 For example, further information may be requested on: potential non-network options (for example, whether there are any alternative non-network solutions not already identified by the RIT-D proponent); non-network credible options (for example, in respect of the potential non-network solutions identified, whether these are commercially and technically feasible at the scale required, and/or likely to be available in a similar timeframe to the network options); or inputs into the RIT-D assessment (for example, in respect of the non-network credible options already identified, the estimated costs and possible market benefits of each credible option).

risk that efficient non-network options are overlooked in the project assessment process, and thus improve the application of the RIT-D assessment.

In respect of the period of consultation required for the non-network options report, the ENA, Ergon Energy and the Victorian DNSPs considered that the requirement for DNSPs to provide stakeholders with a minimum four month period to provide submissions was too long and disproportionate to other consultation periods in the NER.

The Commission notes that the four month consultation period was considered appropriate in order to allow sufficient time for interested stakeholders to provide submissions, and non-network proponents to consider and potentially develop proposals for non-network solutions. Further, in respect of the RIT-T project specification consultation report (the equivalent report), the period of consultation must not be less than 12 weeks from the date of publication of the report. The decision to provide four months rather than three was considered appropriate given distribution projects are more likely to attract non-network options relative to transmission projects.

However, having considered the arguments and evidence put forward in submissions to the draft rule determination, the Commission has determined to amend the period of consultation on the non-network options report from four months to a minimum period of three months. The Commission expects that three months should be sufficient to allow stakeholders to consider the report and prepare submissions in line with the intended objectives.

Draft project assessment report

The proposed rule provided that, within 12 months (or any longer time period as agreed in writing by the AER) of either: (1) the end of consultation on the project specification report; or (2) where a project specification report is not required, the publication of the specification threshold test notice, a DNSP must prepare and publish a draft project assessment report setting out certain specified information.[255]

The purpose of the draft project assessment report was to provide greater transparency in respect of a DNSP's decision making process, including in respect of its consideration and assessment of the range of credible options, and the identification of the preferred option. In the draft rule determination, the Commission considered this would promote greater consultation with, and encourage participation by, interested stakeholders in the network planning process.

The proposed rule also required that interested stakeholders be provided with a minimum period of six weeks to make a submission to the draft project assessment report. The Commission considered that specifying a minimum timeframe for

255 The required content of the draft project assessment report is set in draft clause 5.17.4(j). This includes (among other things): a description of each credible option assessed; quantification of applicable costs and, where relevant, applicable market benefits; the results of the net present value analysis of each credible option; and the identification of the proposed preferred option.

consultation would provide relevant NSPs with greater certainty regarding the impact of the RIT-D process on the timing of an investment, thereby assisting those NSPs to better manage any risk associated with the RIT-D process.

Subject to a few minor amendments to accommodate changes to the non-network option screening process and non-network option report, the draft rule maintained the arrangements set out within the proposed rule.[256]

Noting that there were no new issued raised in submissions to the draft rule determination in respect of the draft project assessment report, the Commission maintains its view set out in the draft rule determination.

Exemptions from preparing a draft project assessment report

The proposed rule provided an exemption from the requirement to prepare and publish a draft project assessment report for projects where: (1) a DNSP was not required to publish a project specification report; and (2) where the estimated capital cost of the proposed preferred option is less than $10 million.[257]

In the draft rule determination, the Commission considered that providing an exemption would help to prevent straightforward projects from being unnecessarily delayed by the project assessment process. It would also reduce the regulatory burden faced by proponents of the RIT-D in conducting the test. Further, the Commission noted that it considered the rule provided sufficient safeguards to prevent the exemption from being inappropriately used, including providing stakeholders with the avenue to raise a dispute where appropriate. The draft rule was therefore reflective of the arrangements set out in the proposed rule.[258]

On the basis that stakeholders did not raise any issues in submissions in respect of this aspect of the draft rule, the Commission maintains its view set out in the draft rule determination.

Final project assessment report

The proposed rule required that, as soon as practicable following either: (1) the end of consultation on the draft project assessment report; or (2) where a project specification report was not required, the publication of a specification threshold test report, a DNSP must publish a final project assessment report.

In the draft rule determination, the Commission noted that, in line with its views in relation to the draft project assessment report, the obligation to publish a final project

256 The draft rule also included a number of minor amendments to accommodate instances where a TNSP is identified as the lead party to carry out the RIT-D as part of the joint planning arrangements.

257 For such investments, DNSPs would be required to publish a final project assessment report following publication of the notice required under draft clause 5.17.4(d).

258 The draft rule also included a number of minor amendments to accommodate instances where a TNSP is identified as the lead party to carry out the RIT-D as part of the joint planning arrangements.

assessment report would further increase transparency in respect of a DNSP's decision making process. This should promote greater consultation with, and encourage participation by, interested stakeholders in the network planning process.

In addition, the proposed rule allowed for DNSPs to publish a final project assessment report as part of their DAPR where the preferred option had an estimated capital cost of less than $20 million. The Commission considered that providing DNSPs with the opportunity publish final project assessment reports within their DAPRs would decrease compliance costs while still providing for the timely publication of RIT-D conclusions for more significant projects.

Subject to a few minor amendments to clarify the information to be included within the final project assessment report,[259] the draft rule largely adopted the arrangements set out in the proposed rule.

In its submission to the draft rule determination, the AER considered the $20 million threshold may be too high as distribution projects above $10 million tend to be major projects and should be subject to their own final report. The AER considered a more appropriate threshold would be $10 million. It considered this would be unlikely to impose an onerous regulatory burden on DNSPs as it was not likely to capture a large number of discrete projects.

Having considered this issue in detail, the Commission still considers that the $20 million threshold is appropriate as a means of managing some of the compliance costs on DNSPs in respect of reporting under the RIT-D process. With that said, it is important to note that DNSPs will only be likely to use this exemption in limited circumstances – specifically, where a preferred option is finalised close to the date of publication of the DAPR. This is because the dispute resolution process will only commence once a final project assessment report has been published, irrespective of whether it is published as a standalone document or within a DAPR. Therefore, by waiting to include a final project assessment report as part of a DAPR, a DNSP may risk potential delays to a project where the timeframes are not closely aligned.

9.4.4 Reapplication of the RIT-D

In its submission to the consultation paper, Energex sought clarification on the circumstances in which a DNSP would be expected to reapply the RIT-D.[260] In addition, the AER requested that the Commission consider whether DNSPs should be required to reapply the RIT-D in certain circumstances, including where a significant period of time has elapsed since completion of an original assessment.[261]

In the draft rule determination, the Commission noted that it would be reasonable and prudent to require a RIT-D proponent to reapply the RIT-D in full and consult with

259 The information requirements differ depending on whether a RIT-D proponent has prepared and published a draft project assessment report. See draft clause 5.17.4(r).

260 Energex, Consultation Paper submission, p. 18.

261 AER, Consultation Paper submission, p. 7.

stakeholders in circumstances where it is no longer likely that an original RIT-D assessment identifies the most efficient option. The draft rule therefore included a provision which specified that (unless otherwise determined by the AER) a RIT-D proponent would be expected to reapply the RIT-D where there was a material change in circumstances which, in the RIT-D proponent's reasonable opinion, meant that the preferred option identified in the original RIT-D assessment was no longer the preferred option. In making a determination, the AER would be expected to have regard to the credible options and the details of the change in circumstances. The Commission considered that further clarity on this issue would help to reduce uncertainty for RIT-D proponents as to when the RIT-D would need to be reapplied, while maintaining the integrity of the RIT-D project assessment process.[262]

In its submission to the draft rule determination, Energex suggested that reapplication of the RIT-D should not be required where a project is urgent or where the additional delay caused by any reapplication would result in the DNSP being unable to meet its reliability standards. In addition, the AER suggested that where a material change in circumstance was a delay in the identified need (for example, due to a change in the demand forecast), DNSPs should be required to wait until the identified need arises again before reapplying the RIT-D. This would ensure that the new assessment included any new credible options which may have arisen since the first application of the RIT-D.

In response to the concern raised by Energex, the final rule clarifies that, where a RIT-D proponent requests that the AER make a determination that reapplication of the RIT-D is not required, the AER must also have regard to (among other things) whether the RIT-D project is required to address a network issue that, if not addressed, is likely to materially adversely affect the reliability and secure operating state of the distribution network, or a significant part of that network. In addition, the final rule states that a material change in circumstances may include, but is not limited to, a change to the key assumptions used in identifying the identified need described in, and/or the credible options assessed in, the final project assessment report.

The Commission considers that reapplication provisions set out in the final rule will provide certainty to RIT-D proponents as to the course of action required where there is a material change in circumstances. This includes, for example, where new information becomes available which was not known nor anticipated at the time of the original assessment, which means that the preferred option identified in the original RIT-D assessment may no longer be the preferred option.[263]

262 There is currently no equivalent provision in the NER for the reapplication of the RIT-T in certain circumstances.

263 The RIT-D provides flexibility for a RIT-D proponent to respond to new information where it is known that new information may become available in the future. The AER's RIT-D application guidelines will provide further guidance and worked examples as to how a RIT-D proponent may respond to uncertainty when applying the RIT-D.

9.4.5 AER review and audit activities

In order to help determine whether or not a DNSP has given due consideration to non-network options in the planning process, the proposed rule provided the AER with specific audit and review powers to: (1) review a DNSP's policies and procedures to determine if non-network options have been duly considered; and (2) audit projects which have been identified by a RIT-D proponent as not meeting the RIT-D cost threshold. These proposals were intended to provide an increased incentive for DNSPs to fully consider non-network solutions for all investment decisions.

In the draft rule determination, the Commission noted that the AER already has a number of functions and powers set out in legislation in relation to monitoring, investigating and enforcing compliance with various aspects of the national energy framework, including with the NER. The AER’s compliance and enforcement strategy sets out the range of mechanisms used to monitor compliance, which include undertaking audits to assess participants' compliance with specific obligations. In addition, the AER issues quarterly compliance reports setting out the results of its monitoring and enforcement activities.

In addition, the Commission noted that it did not consider it appropriate for the NER to mandate and prioritise the AER’s compliance and enforcement activities. The AER's approach to compliance is based on a risk assessment of the impact and probability of breaches of particular obligations. It is also variable over time, as needed and in light of changes in the market and other matters. This approach is set out in the AER's compliance and enforcement statement of approach document.[264]

For this reason, the draft rule did not include additional powers for the AER to review and audit DNSPs activities regarding the consideration of non-network options.

Noting that no new issues were raised on this matter in submissions to the draft rule determination, the Commission has maintained its view set out in the draft rule determination.

9.4.6 RIT-D and RIT-D application guidelines

At the same time the AER publishes the RIT-D, the proposed rule required that the AER also publish guidelines (RIT-D application guidelines) on the operation and application of the RIT-D. This would include information on how disputes in relation to the application of the RIT-D would be addressed and resolved by the AER.

The proposed rule set out the information that the AER would be required to provide in the RIT-D application guidelines. This would include guidance and worked examples on various aspects of the test, such as: what constitutes a credible option; acceptable methodologies for valuing the market benefits and costs of a particular credible option; what may constitute an externality under the RIT-D; the appropriate approach to undertaking a sensitivity analysis; and the appropriate approaches to

264 AER 2010, *Compliance and Enforcement*, *Statement of Approach*, December 2010. See: www.aer.gov.au.

assessing uncertainties and risks. This information would assist NSPs in applying the RIT-D in accordance with the rules.

In the draft rule determination, it was noted that the RIT-D application guidelines were intended to work together with the test and the RIT-D principles (set out in the rules) to effectively govern the application of the RIT-D. These arrangements reflected an appropriate balance between the rules prescribing the framework necessary to achieve the objectives of the RIT-D, and the AER developing and administering the test, and ensuring compliance with the rules.

The proposed rule also provided the AER with the option of publishing the RIT-D and RIT-D application guidelines together with the RIT-T and RIT-T application guidelines as a single document. This could provide for greater efficiency in the AER's processes and may improve consistency between the RIT-T and RIT-D.

Subject to a few minor amendments to clarify the scope of guidance to be provided by the AER, the draft rule largely adopted the arrangements set out in the proposed rule in relation to the publication of the RIT-D application guidelines.

On the basis that stakeholders did not raise any issues in submissions in respect of this aspect of the draft rule, the Commission maintains its view set out in the draft rule determination.

The draft rule provided the AER with a period of nine months following the commencement of the rule to develop and publish the RIT-D and RIT-D application guidelines. This timeframe is discussed further in section 11.4.2.

9.5 Rule making test

The Commission is satisfied that the RIT-D arrangements set out in the final rule will, or are likely to, better contribute to the achievement of the NEO than the proposed rule. The final rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity through:

- promoting greater consultation with stakeholders which should assist in the identification, consideration and quantification of all relevant investment options and associated costs and benefits;
- improving consistency and transparency of distribution investment assessments, thereby promoting more efficient decision making by NSPs; and
- facilitating a more strategic assessment of projects which should optimise decision making and improve the efficiency of the distribution assessment process.

The Commission also considers that the final rule will promote good regulatory practice by subjecting the appropriate range of projects to a robust economic assessment without imposing an unreasonable burden on DNSPs in respect of the timing and resources required to conduct the process.

The project assessment process for the RIT-D is broadly consistent with the project assessment process for the RIT-T, subject to a number of additional mechanisms which recognise the nature and volume of investments undertaken at the distribution level. In addition to promoting efficient investment in distribution networks, the final rules for the RIT-D also achieve consistency with the transmission arrangements.

10 Dispute resolution process

This chapter sets out the Commission's views in relation to the dispute resolution process, having regard to the views of stakeholders in submissions to the consultation paper and draft rule determination. This chapter is structured as follows:

- section 10.1 describes the proposed dispute resolution process and summarises stakeholder responses to the first round of consultation on this matter;
- section 10.2 describes the dispute resolution process set out in the draft rule and summarises stakeholder responses to the second round of consultation on this matter;
- section 10.3 sets out the differences between the draft rule and the final rule;
- section 10.4 sets out the Commission's assessment of the final rule in respect of the dispute resolution process; and
- based on the Commission's assessment in section 10.4, section 10.5 sets out the Commission's conclusions on this matter.

10.1 Proposed rule

10.1.1 Description of the proposed rule

The rule change request proposes to introduce a specific dispute resolution process for the RIT-D which has been based on the dispute resolution process for the RIT-T. The proposed rule intends that:

- the dispute resolution process would be a compliance only review and only apply to a DNSP's application of the RIT-D against the requirements in the rules;
- the process would apply to all investments which are subject to the RIT-D and would cover all matters set out by a DNSP in the final project assessment report;
- the dispute resolution process would be conducted by the AER;
- registered participants, AEMO, the AEMC, connection applicants, intending participants, interested parties[265] and non-network providers would be able to dispute matters set out in a DNSP's final project assessment report within 30 days of the publication of the final project assessment report;

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265 The proposed rule sought to amend the definition of 'interested party' as currently defined in Chapter 10 of the NER as follows: "a person including an end user or its *representative* who, in the AER's opinion, has, or identifies itself to the AER as having the potential to suffer a material and adverse market impact from the proposed *transmission investment* or *distribution investment* (as the case may be) that is the *preferred option* identified in the *project assessment conclusions report* or the *final project assessment report* (as the case may be)."

- within 40 to 100 business days of receiving the dispute notice (depending on the complexity of the dispute), the AER would either:
  - reject the dispute where it determines that the grounds for the dispute are invalid, misconceived or lacking in substance; or
  - make a determination on the dispute to direct the DNSP to amend its final project assessment report if:
    - the DNSP has not correctly applied the RIT-D in accordance with the rules; or
    - the DNSP has made a manifest error in its calculations; and
- in making a determination on a dispute, the AER would specify the timeframe for the DNSP to amend its final project assessment report.

The proposed rule would also allow the AER to grant exemptions from the dispute resolution process if it considers the need for the relevant distribution investment to proceed outweighs the benefits from conducting the dispute resolution process.

Current arrangements

Currently, disputes regarding the application of the regulatory test by DNSPs must be resolved according to the dispute resolution process in Chapter 8 of the NER. These provisions are general in nature and not tailored to the specific types of disputes that may be raised in relation to distribution planning. Further, the dispute resolution process in Chapter 8 of the NER only applies to disputes between registered participants. There are currently no formal jurisdictional dispute resolution processes for distribution in any of the NEM jurisdictions.

10.1.2 Proponent's view

The rule change request notes that the proposed dispute resolution process is intended to provide greater transparency and clarity regarding how disputes can be resolved and the obligations on disputing parties. The proponent considers that the proposed process would allow disputes to be resolved in a timely manner, ensuring that distribution investments are not unduly delayed.[266]

10.1.3 Stakeholder views - first round of consultation

Scope of the dispute resolution process

The ENA, Ergon Energy and the AER were supportive of the proposal to limit the scope of the dispute resolution process to a DNSP's compliance with the RIT-D

266 MCE, Rule Change Request, 30 March 2011.

rules.[267] The ENA considered that a compliance only review would reduce the administrative burden and other costs on DNSPs and the AER, while also reducing the likelihood of unnecessary delays in the assessment of distribution projects.[268]

In relation to the scope of parties eligible to raise a dispute, stakeholders were divided on this issue. Aurora Energy, EnerNOC and Ergon Energy noted support for the proposed scope of potential dispute applicants.[269] However, almost half of the DNSPs who provided a submission considered the proposed scope was too broad and unlikely to prevent vexatious claims being lodged and projects being delayed.[270]

As an alternative, the Victorian DNSPs suggested limiting the scope of potential dispute applicants to connection applicants, AEMO and affected registered participants.[271] The ENA, Energex and Ergon Energy suggested that parties should be prevented from raising a dispute in relation to any issue that could have been raised during consultation on the RIT-D draft project assessment report.[272] Ergon Energy suggested that disputes be disallowed where the party lodging a dispute had not submitted a non-network proposal to the project specification report.[273] Endeavour Energy also suggested limiting the scope of parties to those who made a submission during the consultation period.[274] Essential Energy suggested that 'relevant and substantive interest' provisions should be included in the rule to clarify valid concerns.[275]

While broadly supportive of the classes of parties that could raise a dispute, the AER considered two aspects of the definition of 'interested party' required further clarification.[276] The AER suggested amending references to "identifies itself as having" and "market" in the definition to remove some ambiguity from the current drafting.

267 ENA, Consultation Paper submission, p. 20; Ergon Energy, Consultation Paper submission, p. 10; AER, Consultation Paper submission, p. 9. ENA, Consultation Paper submission, p. 20.

268 ENA, Consultation Paper submission, p. 20.

269 Ergon Energy’s support was premised on adequate controls being in place to minimise vexatious or frivolous disputes. Ergon Energy, Consultation Paper submission, p. 10; Aurora Energy, Consultation Paper submission, p. 8; EnerNOC, Consultation Paper submission, p. 6.

270 Endeavour Energy, Consultation Paper submission, p. 9; Victorian DNSPs, Consultation Paper submission, p. 6; Essential Energy, Consultation Paper submission, p. 8; Ergon Energy, Consultation Paper submission, p. 24; Energex, Consultation Paper submission, p. 18; ENA, Consultation Paper submission, pp. 20-21.

271 Victorian DNSPs, Consultation Paper submission, p. 6.

272 ENA, Consultation Paper submission, pp. 20-21; Ergon Energy, Consultation Paper submission, p. 24; Energex, Consultation Paper submission, p. 18.

273 Ergon Energy, Consultation Paper submission, p. 24.

274 Endeavour Energy, Consultation Paper submission, p. 9.

275 Essential Energy, Consultation Paper submission, p. 8.

276 AER, Consultation Paper submission, p. 9.

Exemptions from the dispute resolution process

A significant number of stakeholders expressed support for the proposal to allow the AER to grant exemptions from the proposed dispute resolution process.[277] Energex noted that certain investments may be time sensitive and essential to maintain security of supply and considered the proposal would allow the AER to act in best interests of the market.[278] In addition, Endeavour Energy considered it may be beneficial to include a clause requiring the AER to consider wider community good in relation to time sensitive projects or projects to address security of supply.[279]

In contrast, the AER considered the proposed exemption process was unnecessary and unlikely to improve the proposed dispute resolution process. The AER was of the view that the circumstances in which it may grant an exemption are adequately dealt with in other provisions of the proposed rule. It noted that urgent and unforeseen investments would be exempt from RIT-D, and that the AER would have the power to dismiss disputes if misconceived or lacking in substance.[280]

10.2 Draft rule

10.2.1 Description of the draft rule

The draft rule largely adopted the proposed rule in relation to the dispute resolution process as described above, subject to a modification considered to improve its application and better promote the NEO. The modification made to the proposed rule was as follows:

- *AER granting of exemptions from the dispute resolution process*: the draft rule removed the ability for the AER to grant an exemption from the dispute resolution process.[281]

The Commission also made a number of minor drafting amendments considered to improve and clarify the application of the dispute resolution process. These amendments did not affect the principles underlying the proposed rule and are detailed in section 10.2.2 of the draft rule determination.[282]

277 Ergon Energy, Consultation Paper submission, p. 10; Energex, Consultation Paper submission, p. 19; Victorian DNSPs, Consultation Paper submission, p. 17; Aurora Energy, Consultation Paper submission, p. 9; EnerNOC, Consultation Paper submission, p. 6; Essential Energy, Consultation Paper submission, p. 8; Endeavour Energy, Consultation Paper submission, p. 10.

278 Energex, Consultation Paper submission, p. 19.

279 Endeavour Energy, Consultation Paper submission p. 10.

280 AER, Consultation Paper submission, p. 10.

281 Proposed clause 5.6.6AC(j).

282 AEMC 2012, *Distribution Network Planning and Expansion Framework*, Rule Determination, AEMC, 14 June 2012, Sydney, p. 110.

10.2.2 Stakeholder views - second round of consultation

Scope of the dispute resolution process

Energex reiterated its concern that the scope of matters that can be disputed, and the scope of parties that can raise a dispute, remains too broad. It considered the draft rule had the potential to increase project delays and costs due to the increased risk of lengthy and protracted disputes. Energex maintained its position that unless the results of the final project assessment report diverged significantly from the draft project assessment report, parties should not be allowed to raise a dispute in relation to any issue that could have been raised during consultation of the draft project assessment report.[283]

Exemptions from the dispute resolution process

The Victorian DNSPs supported the reinstatement of provisions which would allow the AER to grant exemptions from the dispute resolution process. These stakeholders considered the advantages of including the provision in the rules would substantially outweigh any disadvantages. The Victorian DNSPs also noted that if the Commission's reasoning for removal of this provision (set out in the draft determination) was correct, the provision would be redundant but its inclusion would have no adverse effects or consequences.[284]

Other comments

In their joint submission to the draft rule determination, the Victorian DNSPs expressed support for clarification on the definition of interested party. These stakeholders accepted that the changes made in the draft rule would appropriately minimise the scope for frivolous disputes to be raised, particularly by end-use customers that may not understand purpose and scope of RIT-D.[285]

In respect of the definition of interested party, Energex suggested that the AEMC define the term ‘adverse market impact’ as per the definition of ‘interested party’ under clause 5.15.1. Energex considered there should be absolute clarity as to who should be deemed an ‘interested party’ for the purposes of raising a dispute.[286]

The AER noted that it was supportive of the dispute resolution procedures set out in the draft rule. In particular, it noted that the AEMC had taken on board its proposals to clarify the definition of interested party and remove the provisions for the AER to grant an exemption from the dispute resolution process.[287]

283 Energex, Draft Rule Determination submission, pp. 24-25.

284 Victorian DNSPs, Draft Rule Determination submission, pp. 24-25.

285 Victorian DNSPs, Draft Rule Determination submission, p. 15.

286 Energex, Draft Rule Determination submission, p. 25.

287 AER, Draft Rule Determination submission, p. 5.

10.3 Differences between the draft rule and final rule

Having regard to the views of stakeholders and its own analysis and review, the Commission has largely adopted the draft rules in relation to the dispute resolution process, subject to two minor amendments to improve and clarify its application. The manner and reasoning for these amendments is set out below.

10.3.1 Amendments

The Commission has made two additional drafting amendments to improve and clarify the application of the final rule without affecting the principles underlying it. This drafting changes are as follows:

- *Scope of matters to be disputed*: the final rule clarifies that a disputing party[288] may, by notice to the AER, dispute "conclusions made by the RIT-D proponent in the final project assessment report" on the grounds that (1) a RIT-D proponent has not applied the RIT-D in accordance with the rules, or (2) there was a manifest error in the calculation performed by the RIT-D proponent in applying the RIT-D.[289]
- *Definition of interested party*: a minor amendment has been made to the definition of "interested party" to clarify that a "material and adverse market impact" experienced by the interested party must arise in the "national electricity market".[290]

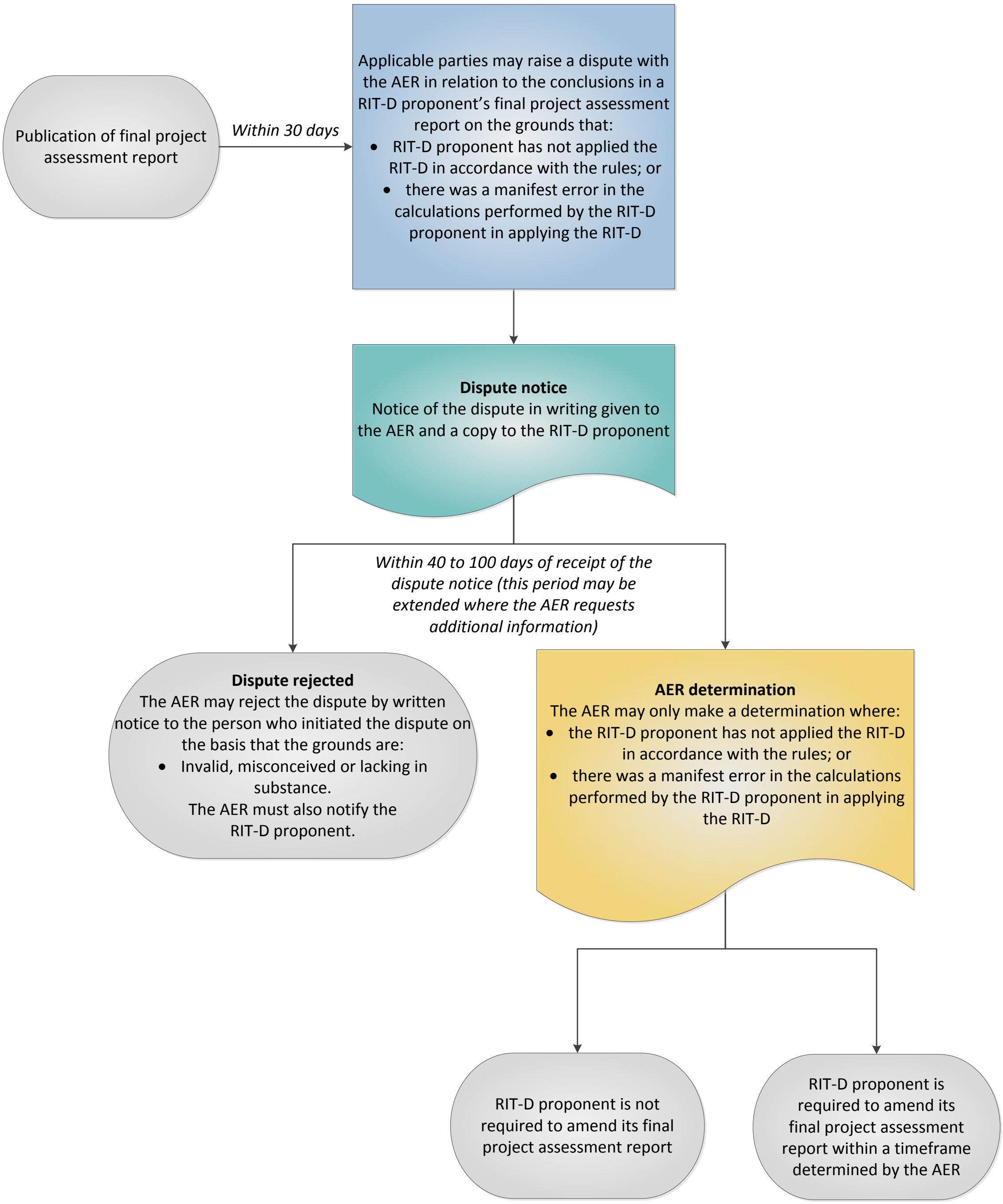
A summary of the dispute resolution process is set out in figure 10.1 below.

288 Registered participants, connection applicants, intending participants, AEMO, interested parties (as defined in Chapter 10 of the NER) and non-network providers.

289 Clause 5.17.5(a).

290 Clause 5.15.1.

Figure 10.1 Dispute resolution process



10.4 Commission's assessment

The Commission has analysed and assessed the policy and drafting issues arising from the rule change request for the dispute resolution process. Outlined below is the Commission's assessment of the final rule, including the reasons why it considers this aspect of the final rule meets the NEO.

10.4.1 Dispute resolution process

Scope of the dispute resolution process

The proposed rule set out arrangements for a dispute resolution process which would enable certain specified parties to raise a dispute with the AER in relation to the matters set out by a DNSP in its final project assessment report. The scope of the dispute resolution process would be limited to a DNSP's compliance with the rules rather than a merits review of NSPs' decisions. This was intended to ensure that NSPs remain the ultimate decision makers regarding which investments are made.

The proposed rule also expanded the scope of parties eligible to raise a dispute with the AER, relative to current arrangements. The expanded scope included the AEMC, AEMO, connection applicants, intending participants, non-network providers, interested parties (as defined in the rules) and registered participants. It was intended that any party who may be impacted by an NSP's decisions under the RIT-D, including non-network providers and interested parties, should have the ability to raise a dispute with the AER concerning a DNSPs application of the RIT-D.

In submissions to the consultation paper, a number of stakeholders expressed concern that the scope of the dispute resolution process was too broad and did not provide appropriate safeguards against baseless or vexatious claims being lodged with the effect of delaying projects.[291] To reduce this risk, a number of stakeholders suggested limiting the scope of parties eligible to raise a dispute to those who had participated in the RIT-D consultation process.[292]

While the Commission acknowledged these concerns in the draft rule determination, it nonetheless considered that the proposed arrangements provided sufficient safeguards to protect against any risk of the dispute resolution process being used inappropriately by some stakeholders in certain circumstances. Importantly, the proposed rule provided the AER with the ability to reject disputes immediately if the grounds for dispute were invalid, misconceived or lacking in substance.

In its submission to the draft rule determination, Energex reiterated its concern that the scope of matters that could be disputed, and the scope of parties that could raise a dispute, remained too broad under the draft rule.[293] However, after reconsidering this issue, the Commission maintains its view set out in the draft rule determination.

The dispute resolution process is an important tool in providing a check on the discretion afforded to NSPs during the RIT-D project assessment process. By providing a transparent and accessible mechanism for parties to raise questions regarding a RIT-D proponent's application of the RIT-D, the arrangements will provide accountability for their behaviour. In addition, in respect of the scope of parties eligible to raise a dispute, the Commission continues to believe that it is appropriate that any

291 Endeavour Energy, Victorian DNSPs, Essential Energy, Ergon Energy, Energex, ENA.

292 ENA, Ergon Energy, Energex.

293 Energex, Draft Rule Determination submission, pp. 24-25.

stakeholder who may be impacted by an NSP's decisions under the RIT-D be provided with the opportunity to raise a compliance issue directly with the AER, without being limited in the circumstances in which it may do so.

With that said, we have reviewed the dispute resolution process and consider the provisions setting out the grounds for a dispute would benefit from further clarification. In particular, draft clause 5.17.5(a), while specifying the grounds for dispute, fails to identify the subject of dispute. Therefore, to ensure that clause 5.17.5(a) is consistent with the provisions relating to the remedy available to the AER in making a determination under the dispute process (detailed in clause 5.17.5(d)(3)), the final rule includes an amendment to clarify that the subject of dispute is the conclusions made by a RIT-D proponent in its final project assessment report.

For the avoidance of doubt, the final rule states that a disputing party may only raise a dispute in relation to the conclusions made by the RIT-D proponent in a final project assessment report on the grounds that:[294]

- the RIT-D proponent has not applied the RIT-D in accordance with the rules; or
- there was a manifest error in the calculations performed by the RIT-D proponent in applying the RIT-D.

In addition, a dispute may not be raised on matters outlined in the final project assessment report which:[295]

- are treated as externalities by the RIT-D; or
- relate to an individual's personal detriment or property rights.

In addition, it should be noted that it is not the intention of the dispute resolution process to provide an avenue for stakeholders to raise disputes simply because they disagree with the conclusions reached by an NSP in its final project assessment report. Rather, the dispute resolution process is intended to provide stakeholders with an opportunity to identify to the AER instances where a RIT-D proponent may not have applied the RIT-D in accordance with the rules, potentially resulting in the RIT-D proponent failing to identify the most efficient option in its final project assessment report. In this instance, it would be necessary for the effectiveness of the process to require the relevant NSP to amend the matters set out in the final project assessment report based on the correct application of the RIT-D rules.

Procedures for a dispute

The proposed rule also set out a clearly defined process in relation to raising and considering disputes, including a limit on the timing for stakeholders to raise a dispute

294 Clause 5.17.5(a).

295 Clause 5.17.5(b).

and on the AER in relation to considering a dispute and determining the outcome.[296] In the draft rule determination, the Commission considered that providing transparency and clarity around these timeframes could provide NSPs with greater certainty regarding the impact of a potential disputes on the timing of an investment. This would assist NSPs to better manage any risk associated with the dispute resolution process.

Noting that stakeholders did not offer substantive comments on this aspect of the draft rule in submissions to the draft rule determination, the Commission maintains its view set out in the draft rule determination on this matter.

Definition of 'interested party'

In its submission to the consultation paper, the AER expressed concern that the current definition of 'interested party' was ambiguous.[297] Having considered the AER's concerns, the Commission determined that without further clarification, the definition of 'interested party' may unintentionally expand the scope of parties eligible to raise a dispute. On this basis, the draft rule clarified that:

- whether or not a person is an interested party for the purposes of this definition is solely a matter for the AER (in its opinion); and
- the material and adverse market impact experienced by the interested party must arise in the national electricity market.

The Commission considered that this clarification would remove the ambiguity, resulting in only the intended parties being eligible to raise a dispute.

Having regard to the views set out in submissions to the draft rule determination on this issue, the Commission has determined to include the amended definition set out in the draft rule, in the final rule.

In response to the suggestion made by Energex that the AEMC define the term 'adverse market impact' to provide clarity as to who should be deemed an 'interested party', the final rule expands the matters to be included in the AER's RIT-D application guidelines to include an explanation of what the AER considers to be "a material and adverse national electricity market impact".[298]

296 Within 30 business days following the publication of a final project assessment report and within 40-100 days of the receipt of a dispute notice, respectively. Note that these timeframes are subject to a 'stop the clock' provision under 5.17.5(h) where the AER requests additional information from a disputing party or RIT-D proponent.

297 The proposed rule defines 'interested party' for the purpose of the RIT-T and RIT-D as: "a person including an end user or its representative who, in the AER's opinion, has, or identifies itself to the AER as having the potential to suffer a material and adverse market impact from the proposed transmission investment or distribution investment (as the case may be) that is the preferred option identified in the project assessment conclusions report or the final project assessment report (as the case may be)." See: AER, Consultation Paper submission, p. 9.

298 Clause 5.17.2(b)(2)(iii).

10.4.2 Exemptions from the dispute resolution process

The proposed rule provided for the AER to grant an exemption from the dispute resolution process where it considered the need for a distribution project to proceed outweighed the benefits from conducting the dispute resolution process.

In the draft rule determination, the Commission was not convinced of the need to provide for exemptions from the dispute resolution process. Importantly, the Commission did not consider it appropriate to require the AER to determine the need for a particular project to proceed on the basis that the regulator should not take over the role of network planner once a dispute has been lodged.

In addition, the Commission noted that the circumstances in which the AER may grant an exemption from the dispute resolution process would be adequately dealt with via other mechanisms built into the process. For example, the draft rule provided for the AER, upon receipt of a dispute notice, to dismiss a dispute if the grounds for the dispute were invalid, misconceived or lacking in substance. In addition, urgent and unforeseen investments (which, arguably, would be the investment type most likely to meet the proposed exemption criteria) would be exempt from the RIT-D, and therefore the dispute resolution process would not be relevant to these projects.

On this basis, the draft rule omitted the proposal to provide the AER with the ability to grant exemptions from the dispute resolution process from the draft rule.

In its submission to the draft rule determination, the Victorian DNSPs supported reinstatement of the proposed provision. They considered the advantages of including this provision in the rules would substantially outweigh any disadvantages.

Having reconsidered the merits of allowing the AER to grant exemptions from the dispute resolution process, the Commission maintains its view set out in the draft rule determination that the circumstances in which the AER may grant an exemption are adequately dealt with in other provisions in the final rule.

10.4.3 Determination that a proposed project satisfies the RIT-D

The rules in relation to the RIT-T currently provide for a TNSP to request, in writing, that the AER make a determination as to whether a preferred option set out in a RIT-T project assessment conclusions report satisfies the RIT-T.[299] While the proposed rule sought to make a number of minor amendments to this clause to accommodate the proposed joint planning arrangements, an equivalent provision was not proposed for inclusion within the new RIT-D rules. In the draft rule determination, the Commission invited stakeholders' views on this matter.

The AER and Aurora Energy both commented on this issue in their submissions. However, while Aurora Energy expressed support for the inclusion of an equivalent provision in the RIT-D rules, the AER was opposed.

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299 Clause 5.16.6.

The AEMC has conferred further with the AER on this issue. The AER was also opposed to the inclusion of this provision in being included within the RIT-T rules. In its submission to the RIT-T draft rule determination, the AER stated that:[300]

> "It is not clear why a TNSP would seek a determination from the AER under this provision. Given the clause only applies where the project assessment conclusions report is not in dispute and the economic regulatory regime does not provide for an ex post review of a TNSP's capital expenditure program, such a determination would have no practical effect. The AER believes that this provision should be removed."

In the final rule determination for the RIT-T, the AEMC acknowledged the AER's concern but noted that the clause mirrored a provision in the regulatory test and had not been considered as part of the National Transmission Planner (NTP) Review.[301] It concluded that any decision on whether or not to delete this provision should be subject to consultation, and as such, a separate rule change request. No rule changes dealing specifically with this issue have been raised with the AEMC.

Having regard to the views of the AER and Aurora Energy in their submissions to the draft rule determination, and having undertaken our own analysis and review, the Commission has determined not to include an equivalent provision in the RIT-D rules. In line with the views put forward by the AER in its original submission to the RIT-T, the Commission considers that, given the current economic regulatory framework, a determination by the AER as to whether a preferred option set out in a RIT-D final project assessment report satisfies the RIT-D would have little practical effect.

10.5 Conclusion

The Commission is satisfied that the arrangements for the dispute resolution process set out in the final rule will, or are likely to, better contribute to the achievement of the NEO than the proposed rule. The final rule is likely to promote efficient investment in distribution networks for the long term interests of consumers of electricity through:

- providing a transparent and accessible mechanism for stakeholders to question NSPs decision making, providing regulatory discipline on NSPs behaviour, thereby promoting efficient decision making;
- building into the process several safeguards to help ensure against distribution projects being unduly delayed, thereby promoting efficient investment in the distribution network; and
- providing clarity for the resolution of disputes by requiring all projects subject to the RIT-D to be within the scope of a common dispute process.

300 AER submission, RIT-T Draft Rule Determination, p. 8.

301 AEMC 2009, *Regulatory Investment Test for Transmission*, Draft Rule Determination, 2 April 2009, Sydney, p. 67.

11 Implementation and transition

This chapter sets out the implementation and transition arrangements designed to facilitate a smooth transition from existing arrangements to the new national framework for distribution network planning and expansion. The Commission is mindful that market participants - in particular, DNSPs - should not face unnecessary regulatory risks from a lack of clarity or certainty about the transition to the new national framework. The Commission has therefore sought to manage the transition efficiently and with as little disruption as possible.

11.1 Proposed rule

11.1.1 Description of the proposed rule

In the Distribution Network Planning and Expansion Review, the AEMC outlined that its recommendations for the design of a national framework were premised on existing jurisdictional arrangements for distribution network annual planning, annual reporting and project assessment being rolled back to coincide with implementation of the national framework.[302] It was intended that this process be progressed by the states and territories, with the assistance of the Commonwealth where necessary, with ongoing engagement from the AEMC throughout the rule change process.[303]

In the review, the AEMC also indicated that various market participants would need time to transition to a national framework, once the rule commenced.[304] Specifically, the AEMC indicated that:

- DNSPs would require a minimum period of nine months (following the making of the rule) before being required to publish their first DAPR. This would provide DNSPs with sufficient time to comply with the new planning and reporting requirements;[305] and

302 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. 9.

303 In its final report for the review, the AEMC indicated that it was appropriate for a 'transition plan' to be developed and agreed by the jurisdictions as part of the MCE's response to the AEMC's final report. In its response to the AEMC's final report, the MCE stated that it supported the AEMC's ongoing engagement with the Commonwealth, states and territories throughout the rule change process, to ensure an efficient transition to the new national framework. See: AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, p. 9; and Ministerial Council on Energy 2010, *Review of National Framework for Electricity Distribution Network planning and Expansion: Response to the Australian Energy Market Commission's Final Report*, September 2010.

304 AEMC 2009, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, Final Report, 23 September 2009, Sydney, pp. 8-9.

305 While the AEMC final report recommended that this transition period apply to DNSPs, the proposed rule did not formally incorporate this time period as a specific provision.

- the AER should be provided with a period of 12 months to develop and prepare the RIT-D and RIT-D application guidelines. The proposed rule therefore provided for a one year transition period to apply before the RIT-D commenced, following the making of the rule.[306]

Although these transitional issues were not discussed in detail in the final report from the AEMC's review, the proposed rule provided DNSPs with a period of nine months following commencement of the rule, to prepare and publish their first demand side engagement document.[307]

11.1.2 Stakeholder views - first round of consultation

Duplication of state and national arrangements

In submissions to the consultation paper, the ENA and several DNSPs expressed concern regarding the potential for duplication of distribution network planning and expansion requirements at a national and jurisdictional level.[308] Energex considered the transition to a national framework may be difficult to achieve given the time required to amend jurisdictional regulatory instruments. It considered this issue needed to be provided for by transitional provisions in the NER.

The ENA considered that a clear commitment needed to be made to removing jurisdictional requirements to accommodate the introduction of the new national framework. The Victorian DNSPs also suggested that the AEMC work with jurisdictions to agree a timetable for implementation, and to ensure the roll-back of jurisdictional frameworks was coordinated.

Transition to a national framework

Aurora Energy expressed concern that the proposed timeframes for market participants to comply with the new requirements would not be appropriate for all jurisdictions.[309] It suggested that each jurisdiction would be best placed to advise the AEMC on transition planning. Essential Energy considered the proposed timeframes for compliance with the new requirements would create significant challenges for DNSPs in New South Wales in particular, given that each business would be in the process of preparing their regulatory proposal due for lodgement in May 2013. It

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306 This 12 month period is provided for in the proposed amendments to the NER Chapter 11 savings and transitional arrangements.

307 Proposed clause 5.6.2AA(m). Note that the proposed rule did not provide timeframes within which DNSPs would be required to have established their demand side engagement database and register.

308 ENA, Consultation Paper submission, pp. 3, 5; Ergon Energy, Consultation Paper submission, p. 4; Energex, Consultation Paper submission, p. 20; Victorian DNSPs, Consultation Paper submission, pp. 6, 7, 17; Endeavour Energy, Consultation Paper submission, p. 10.

309 Aurora Energy, Consultation Paper submission, p. 10.

suggested that a more appropriate commencement date for NSW DNSPs would be mid-2014.[310]

In contrast, the Victorian DNSPs considered the timings provided for DNSPs to transition to the national framework, although challenging, would be achievable.[311] The Victorian DNSPs supported the proposed nine months for preparation of the first DAPR and the proposed transitional period of 12 months for the RIT-D. However, they also suggested that the rule include a 12 month transitional period for the RIT-T for joint investments.

Transition from the regulatory test to the RIT-D

A number of DNSPs were concerned that the proposed rule did not provide guidance regarding the stage at which DNSPs would be required to comply with the RIT-D for projects that had commenced under the regulatory test.[312] These stakeholders suggested that any project assessment not complete at the date of the relevant amendment to the RIT-D and/or the RIT-D application guidelines should continue and be completed under the regulatory test.

In their supplementary submissions, two of these stakeholders further suggested that the draft rules provide for DNSPs to identify to the AER (at the time of the final determination) the proposed projects which had commenced data analysis under the regulatory test, and which DNSPs intend to complete their assessment under the regulatory test.[313] These projects would then be exempt from the requirements of the RIT-D project assessment process.

In addition, several stakeholders were concerned that the proposed rule did not acknowledge that compliance with the RIT-D could only commence after publication of the RIT-D rules and associated application guidelines. These stakeholders suggested that the rules should specify the timeframe, after the release of the application guidelines, within which a DNSP would be required to comply.[314] The ENA and Energex considered a six month transitional period was necessary.[315] Ergon Energy considered a transitional period of at least 12 months would be required in order to provide DNSPs with sufficient time to understand the new regulatory requirements and to adapt processes, procedures, documentation and information systems, as

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310 Essential Energy, Consultation Paper submission, p. 8.

311 Victorian DNSPs, Consultation Paper submission, p. 6.

312 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 21; Essential Energy, Consultation Paper submission, p. 9; Endeavour Energy, Consultation Paper submission, p. 10.

313 ENA, Consultation Paper supplementary submission, pp. 1-2; Energex, Consultation Paper supplementary submission, p. 4.

314 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 20; Ergon Energy, Consultation Paper submission, pp. 4, 17; Endeavour Energy, Consultation Paper submission, p. 11.

315 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 20.

relevant.[316] Endeavour Energy also noted that DNSPs would require time to train and prepare staff for the commencement of the rule, to ensure compliance.[317]

11.2 Draft rule

11.2.1 Description of the draft rule

The draft rule made a number of modifications to the transition and implementation arrangements set out in the proposed rule. These amendments were considered to improve its application and better promote the NEO. The modifications made to the proposed rule were as follows:

- *Publication of the first DAPR*: the draft rule included a transitional provision providing DNSPs with a minimum period of six months after the rule commenced before being required to publish their first DAPR.[318]
- *DAPR content*: the draft rule included a transitional provision clarifying that DNSPs would not be required to report on projects assessed under the RIT-D in their DAPRs until such time as the RIT-D rules commence. DNSPs would, however, be required to report on projects which have been (or will be) assessed under the regulatory test during that period.[319]
- *Establishment of the demand side engagement register*: the draft rule included a new provision requiring DNSPs to establish their demand side engagement register by the date of publication of their first demand side engagement document.[320]
- *Publication of the RIT-D and RIT-D application guidelines*: the draft rule required the AER to develop and publish the RIT-D and RIT-D application guidelines within nine months of the commencement of the rule.[321]
- *Transition from the regulatory test to the RIT-D*: the draft rule included a number of transitional provisions, including requiring that:
  - NSPs submit to the AER, by 31 December 2013, a list of projects which the NSP has commenced assessing under the regulatory test. Unless otherwise determined by the AER, these projects would be exempt from consideration under the RIT-D project assessment process and would continue to be assessed under the regulatory test;[322] and

316 Ergon Energy, Consultation Paper submission, pp. 4, 17.

317 Endeavour Energy, Consultation Paper submission, p. 11.

318 Draft clause 11.[xx].2.

319 Draft clause 11.[xx].4.

320 Draft clause 5.13.2(j).

321 Draft clause 5.17.2(d).

322 Draft clause 11.[xx].3(c).

- in the first RIT-D application guidelines, the AER provide guidance as to when a regulatory test assessment will be considered to have 'commenced'.[323]

In line with the proposed rule, the draft rule also provided for the RIT-D to commence 12 months after the date the rule commences (where the Commission determined to make a final rule). The Commission also identified 1 January 2013 as a possible date for commencement of a final rule.

11.2.2 Stakeholder views - second round of consultation

In its submission to the draft rule determination, Aurora Energy stated that it considered the savings and transitional rules proposed in the draft rule were adequate.[324]

The Victorian DNSPs noted that the draft rule would require application of the RIT-T to relevant joint planning projects from the date the rule commenced. These stakeholders suggested that it would be preferable for the rules to provide a 12 month transition period (consistent with the proposed period for transition to the RIT-D). In this way, the RIT-T would only apply to joint planning projects from the date 12 months after commencement of the rule.[325]

11.3 Differences between the draft rule and final rule

Having regard to the views of stakeholders and its own analysis and review, the Commission has largely adopted the draft rules in relation to the implementation and transition arrangements, subject to a number of minor drafting amendments to improve and clarify its application. The manner and reasoning for these amendments is set out below.

11.3.1 Amendments

The Commission has made a number of additional, minor drafting amendments to improve and clarify the application of the final rule without affecting the principles underlying it. These drafting changes are as follows:

- *DAPR content*: the final rule clarifies that DNSPs are not required to include in the first DAPR the information specified in schedule 5.8(a)(5) if information on energy and demand forecasts was not required to be reported under jurisdictional electricity legislation applicable at the time the previous report was prepared.[326]

323 Draft clause 11.[xx].3(d).

324 Aurora Energy, Draft Rule Determination submission, p. 3.

325 Victorian DNSPs, Draft Rule Determination submission, p. 16.

326 Clause 11.50.3.

- *Publication of the first demand side engagement document*: the final rule clarifies that the first demand side engagement document must be published no later than 31 August 2013.[327]

- *Publication of the RIT-D and RIT-D application guidelines*: the final rule clarifies that the RIT-D and RIT-D application guidelines must be published no later than 31 August 2013.[328]

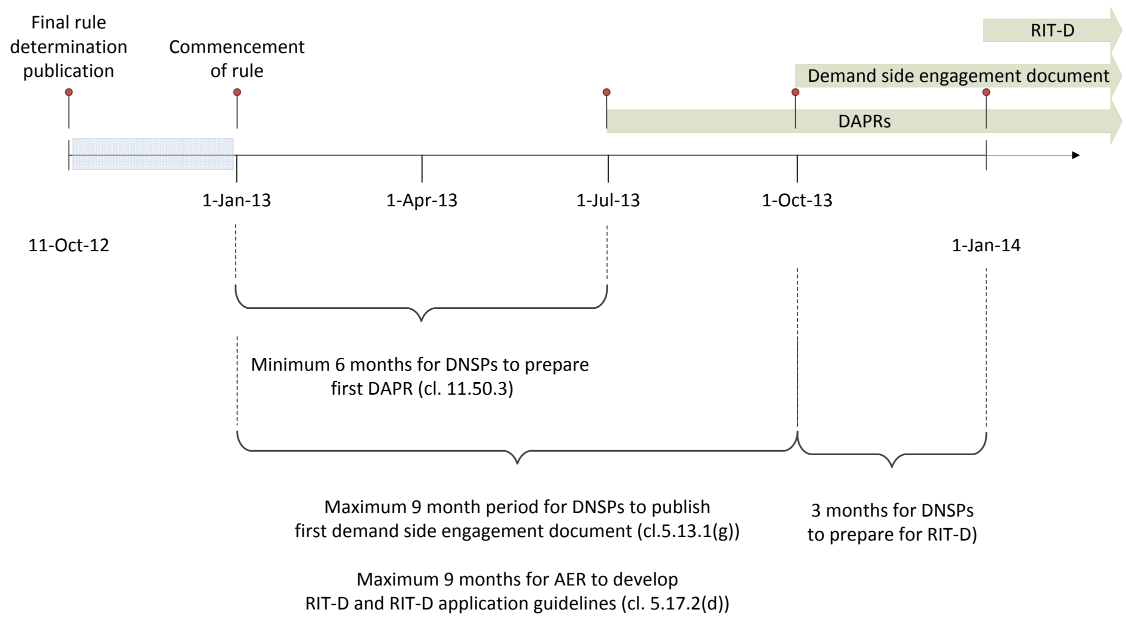
- *Transition from the regulatory test to the RIT-T or RIT-D (where relevant) for joint planning projects*: the final rule clarifies that joint planning projects for which assessment under the regulatory test has commenced as at 31 December 2013 would continue to be assessed under the regulatory test.[329]

- *Other minor changes*: several amendments have also been made to the clause reference numbers in section 11.50.4 to accommodate changes to the transition rule in relation to the content of the DAPR.[330]

In addition, and as set out in section 2.1, the final rule will commence on 1 January 2013.[331]

A summary of the implementation timeframes is set out in figure 11.1 below.

Figure 11.1 Implementation and transition timeframes



327 Clause 5.13.1(g).

328 Clause 5.17.2(d).

329 Clause 11.50.5 (definition of "regulatory test project").

330 Clause 11.50.4.

331 Schedule 5 of the final rule contains some changes to NER Chapters 6 and 6A that are consequential to the commencement of the RIT-D. These provisions will commence on 1 January 2014.

11.4 Commission's assessment

11.4.1 Date of commencement of the final rule

The Commission has identified 1 January 2013 as the commencement date for the final rule. Based on the information made available from jurisdictions, this date will allow the majority of DNSPs to prepare their annual planning reports for 2012 under existing arrangements, while providing a minimum period of six month for DNSPs to prepare their annual planning reports for 2013 under the new arrangements.[332]

The Commission understands that all jurisdictions have commenced (to varying degrees) the process of reviewing and rolling back duplicate state based planning arrangements. Commencement of the final rule on 1 January 2013should therefore allow sufficient time for the jurisdictions to make the necessary amendments to relevant state based instruments to ensure that there is no duplication with the national framework.

11.4.2 Transition arrangements

Publication of the first DAPR

It was intended that DNSPs be provided with a minimum period of nine months before being required to publish their first DAPR. This period of time (beginning from the date the rule commenced) was considered sufficient to enable DNSPs to comply with the new planning and reporting requirements.

In the draft rule determination, the Commission noted that while it recognised the importance of providing DNSPs with sufficient time to undertake the necessary preparatory work to ensure compliance with the new reporting requirements, it also recognised the importance of achieving the benefits of DNSPs reporting under the new national framework in a timely manner. Assuming a commencement date of 1 January 2013 for the final rule, providing DNSPs with a minimum period of nine months to prepare their first DAPR would result in a number of DNSPs not publishing a DAPR until 2014 – a considerable period of time after the start of the rule.[333]

The draft rule therefore provided DNSPs with a minimum period of six months from the proposed commencement date of the rule before being required to publish the first DAPR. This would ensure that the majority of DNSPs publish an annual planning report for 2013 under the new national framework.

In submissions to the draft rule determination, stakeholders did not raise any specific issues in respect of the proposed six month transition period. The Commission therefore maintains its view set out in the draft rule determination that this period is

332 This is based on the assumption that each jurisdiction will retain the current dates set out in jurisdictional legislation as the 'DAPR date' (with the exception of NSW, which does not currently prescribe a date for publication of network management plans).

333 For example, those DNSPs whose DAPR date is specified in the period from January to September.

appropriate. DNSPs have also been provided with additional time in between publication of this final rule determination and commencement of the rule to prepare for compliance with the new arrangements from 1 January 2013.

Publication of the first demand side engagement document

The proposed rule provided DNSPs with a maximum period of nine months to publish their first demand side engagement document. In the draft rule determination, the Commission considered nine months would be sufficient for DNSPs to prepare the information required for publication in this document.

The proposed rule did not specify a timeframe within which DNSPs would be required to have established their demand side engagement registers. In the draft rule determination, the Commission considered it was appropriate to require that the register be established by the date a DNSP publishes its demand side engagement document. The draft rule therefore reflected this intent.

In submissions to the draft rule determination, several stakeholders were concerned that the demand side engagement document was required to be published no later than the date by which the AER was required to publish the RIT-D and RIT-D application guidelines.[334]

In response, the Commission notes that, to the extent that the demand side engagement strategy and RIT-D are linked, the demand side engagement document can be amended and updated by DNSPs at any time, outside of any formal process in the rules. In addition, we expect that DNSPs will have commenced preparations for transition to the new RIT-D prior to the AER finalising the test and application guidelines. At the very least, publication of the draft RIT-D and RIT-D application guidelines should provide DNSPs with a level of information sufficient to understand the new regulatory requirements and to produce the demand side engagement document. For this reason, the final rule maintains a maximum nine month transition period for publication of the demand side engagement document.

Publication of the RIT-D and RIT-D application guidelines

The proposed rule did not specify a date by which the AER was required to publish the RIT-D and RIT-D application guidelines. However, given that the proposed rule provided for a one year transition period to apply before commencement of the RIT-D, it was expected that the AER would develop and publish the RIT-D and RIT-D application guidelines by the date 12 months following commencement of the rule.[335]

In the draft rule determination, the Commission acknowledged that it was important to ensure that sufficient time was made available for the AER to develop the RIT-D and RIT-D application guidelines in accordance with the distribution consultation procedures, including providing stakeholders with adequate time to respond to key issues. However, this needs to be balanced with the need to ensure that this initial step

334 Energex and Essential Energy.

335 Proposed clause 11.30.

in the RIT-D implementation process is undertaken in an efficient and timely manner. Given that the AER has considerable experience in the current regulatory test and the RIT-T, providing the AER with a period of nine months to prepare and publish the RIT-D and application guidelines would achieve an appropriate balance between these objectives. The draft rule therefore required the AER to publish the test and guidelines nine months from commencement of the rule.

In submissions to the draft rule determination, stakeholders did not raise any specific issues in respect of the proposed timeframe for publication of the RIT-D and RIT-D application guidelines. The Commission therefore maintains its view set out in the draft rule determination that this period is appropriate.

Commencement of the RIT-D

As noted previously, the proposed rule provided for a one year transition period to apply before commencement of the RIT-D. During this period, the AER would be required to develop and publish the RIT-D and RIT-D application guidelines.

In submissions to the consultation paper, a number of stakeholders expressed concern that the proposed rule did not specify a date following the release by the AER of the RIT-D and RIT-D application guidelines by which DNSPs would be expected to comply with the new RIT-D rules. Stakeholders suggested that six months[336] or a period of at least 12 months[337] would be required.

Having considered this issue, the draft rule provided DNSPs with a period of three months following publication of the RIT-D and RIT-D application guidelines in order to finalise preparations for compliance with the new RIT-D project assessment and consultation process. The Commission considered three months was appropriate given that DNSPs would be expected to have commenced preparations for transition to the new RIT-D prior to the AER finalising the test and application guidelines. At the very least, publication of the draft RIT-D and RIT-D application guidelines should provide DNSPs with a level of information sufficient to understand the new regulatory requirements and begin the process of adapting processes and procedures to ensure compliance.[338]

Stakeholders did not raise any specific issues in respect of this matter in submissions to the draft rule determination. The Commission therefore maintains its view set out in the draft rule determination that a three month transition period is appropriate.[339]

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336 ENA, Consultation Paper submission, p. 22; Energex, Consultation Paper submission, p. 21.

337 Ergon Energy, Consultation Paper submission, p. 10.

338 No change has been made to the proposed rule which requires the RIT-D to commence 12 months after the date the rule commences. Rather, the three month transition period will arise as an outcome of the amended timeframe provided to the AER to develop and publish the RIT-D and application guidelines.

339 To give effect to these arrangements, the savings and transitional rules include two commencement dates: clauses 11.50.1-11.50.4 and clause 11.50.6 will commence on 1 January 2013 (the "commencement date"); clause 11.50.5 will commence on 1 January 2014 (the "RIT-D commencement date").

Transition from the regulatory test to the RIT-D

In submissions to the consultation paper, a number of DNSPs were concerned that the proposed rule did not provide guidance regarding the stage at which DNSPs would be required to comply with the RIT-D for projects that had commenced assessment under the regulatory test. Two stakeholders suggested that the draft rules provide for identification to the AER (at the time of the final determination) of proposed projects which had commenced data analysis under the regulatory test.[340] These projects would then be exempt from assessment under the RIT-D project assessment process.

In the draft rule determination, the Commission clarified that it was not the intention for a RIT-D project which has commenced (or recently completed) assessment under the regulatory test to undergo further assessment under the RIT-D project assessment process once the RIT-D rules commence. In order to provide clarity on this issue, the draft rule included a transitional provision requiring DNSPs to submit to the AER, by 31 December 2013, a list of RIT-D projects which have commenced assessment under the regulatory test.[341] Unless otherwise determined by the AER, these projects would then be exempt from consideration under the RIT-D (and would continue assessment under the regulatory test). The Commission considered that this approach would provide an effective and efficient means of facilitating a smooth transition to the new project assessment process.

The draft rule did not include a formal process around the approval by the AER of a DNSPs list of RIT-D projects considered to have commenced assessment under the regulatory test. However, it is expected that there would be some interaction between the AER and DNSPs in finalising and approving the lists.

To provide some clarity on when the AER would consider a regulatory test assessment to have commenced, the draft rule also required the AER to provide guidance on the meaning of this term in its RIT-D application guidelines.[342]

Stakeholders did not raise any specific issues in respect of this issue in submissions to the draft rule determination. The Commission therefore maintains its view set out in the draft rule determination on this matter.

Transition from the regulatory test to the RIT-T or RIT-D (where relevant) for joint planning projects

It is intended that NSPs would comply with the joint planning provisions set out under clause 5.14 from the date of commencement of the final rule. However, until such time

340 ENA, Consultation Paper supplementary submission, pp. 1-2; Energex, Consultation Paper supplementary submission, p. 4.

341 Draft clause 11.50.5.

342 Requiring the AER to provide guidance in the RIT-D application guidelines would also minimise the risk that DNSPs' interpretations of the term ‘commenced assessment’ may be influenced by a desire to subject as many projects as possible to the requirements of the regulatory test rather than to the requirements of the new RIT-D project assessment process.

as the RIT-D rules commence on 1 January 2014, the current assessment process for joint planning projects will not change.

For the avoidance of doubt, DNSPs would also be required to include on their list of RIT-D projects to be provided to the AER by 31 December 2013, any RIT-D projects which are joint planning projects and which have commenced assessment under the regulatory test. These joint planning projects would be exempt from consideration under the RIT-D (but would continue assessment under the regulatory test).[343]

11.5 Rule making test

The Commission is satisfied that the implementation and transitional rules as set out in the final rule are appropriate and will, or are likely to, contribute to the achievement of the NEO. The final rule should ensure a smooth transition to the new distribution planning and expansion framework without creating unnecessary regulatory burden for market participants affected by the rule.

343 This has been effected by changes to clause 11.50.5 and the definition of "regulatory test project".

Abbreviations

ACG	Allen Consulting Group
ACT	Australian Capital Territory
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CDC	Copper Development Centre
CEO	Chief Executive Officer
COAG	Council of Australian Governments
Commission	See AEMC
CPRS	Carbon Pollution Reduction Scheme
DAPR	Distribution annual planning report
DNSP	Distribution network service provider
DSP	Demand side participation
DUOS	Distribution use of system
ENA	Energy Networks Association
EURCC	Energy Users Rule Change Committee
MCE	Ministerial Council on Energy
MCE SCO	MCE Standing Committee of Officials
MW	Megawatts
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market

NEO	National Electricity Objective
NER	National Electricity Rules
NERA	NERA Economic Consulting
NPV	Net present value
NSP	Network service provider
NTP	National Transmission Planner
Proponent	See MCE
RET	Renewable Energy Target
RIN	Regulatory information notice
RIT-D	Regulatory investment test for distribution
RIT-T	Regulatory investment test for transmission
SA	South Australia
SCER	Standing Council on Energy and Resources
STT	specification threshold test
TAPR	Transmission annual planning report
TEC	Total Environment Centre
TFR	Transmission Frameworks Review
The Review	Review of National Framework for Electricity Distribution Network Planning and Expansion
TNSP	Transmission network service provider

A Summary of policy issues raised in submissions to the draft rule determination

The table below provides a summary of the policy issues raised by stakeholders in their submissions to the draft rule determination. The table, ordered by key sections of the draft rule, sets out the Commission's response to each issue. For ease of reference, the relevant page numbers have been included in the table.

The submissions received are available on the AEMC website at www.aemc.gov.au.

Stakeholder	Issue	AEMC response
Distribution annual planning review		
5.13.1 Requirements		
Energex	5.13.1(d)(1): suggests the AEMC consider amending clause 5.13.1(d)(1) to include bulk supply substations. Zone substations connect between the sub-transmission and distribution networks. A bulk supply substation connects with the transmission and sub-transmission network. (p. 2)	Clause 5.13.1(c) requires that the distribution annual planning review include all assets that would be expected to have a material impact on the DNSPs network over the forward planning period. In accordance with this clause, DNSPs are required to apply the requirements of the planning review to any assets which, although not specified under clause 5.13.1(d), meet the requirement under clause 5.13.1(c). This may include bulk supply stations.
Energex	5.13.1(d)(vi): suggests the AEMC also consider amending clause 5.13.1(d)(vi) to replace 'embedded generating units' with 'known embedded generating units'. There may be some embedded generators that the DNSP is unaware of due to them being located deep within the customer's own network. (pp. 2-3)	Under industry best practice, we would expect DNSPs to be aware of all embedded generating units which are likely to impact on their forecasts of maximum demands. However, for clarity, we have amended clause 5.13.1(d)(vi) in line with Energex's suggestion.
Energex	5.13.1(d)(2)(v): suggests that the AEMC consider amending clause 5.13.1(d)(2)(v) to include 'the requirement for voltage regulation and other aspects of power quality; and…' or if it implements Energex's suggestions below, replace 'voltage regulation' with 'power quality'.	Clause 5.13.1(d)(2) requires each DNSP to identify limitations on their networks, including limitations caused by one or more of the factors listed. The list of factors is not exhaustive and is intended as guidance. However, we recognise that voltage regulation is only one aspect of

Stakeholder	Issue	AEMC response
	(p. 3)	power quality and have therefore amended clause 5.13.1(d)(2) to include “other aspects of quality of supply to other Network Users”.
Energex	5.13.1(d)(2)(v): suggests the current definition of voltage fluctuation is too restrictive as it implies voltage perturbations only whereas "power quality" refers to current unbalance limits, harmonic limits in addition to voltage limits. Notes that voltage regulation is part of a suite of 'power quality' requirements defined in several Australian Standards. Energex therefore suggests that "voltage regulation' should be replaced with "power quality" to better reflect Australian planning standards. (pp. 4-5)	Noted. As above.
Distribution annual planning report		
5.13.2 General		
Endeavour Energy	Submits that, where there is not a jurisdictional requirement for a planning date, then a default date of 30 June should be specified in the rule. As NSW does not have a jurisdictionally mandated annual planning date, the draft rule mandated 31 December date by which the DAPR must be published will apply. Noted it has previously submitted that jurisdictions should be allowed to determine the start date for the annual planning period based on variations in seasonal loading across DNSPs. Endeavours network predominately experiences its peak loading during summer and it has traditionally aligned its planning practices to ensure a forward plan is in place prior to the start of summer each year. (p. 1)	The final rule removes reference to the forward planning period commencing “one day after the DAPR date”. We note that clause 5.13.1(a)(1) specifies that a DNSP must “determine an appropriate forward planning period for its distribution assets”. In addition, clause 5.13.1(b) states that “the minimum forward planning period for the purposes of the annual planning review is 5 years”. Together, we consider these provisions are sufficient to ensure that DNSPs plan and report over a forward, minimum five year, period commencing on a date deemed appropriate by each DNSP. On this basis, we do not consider it necessary to amend the default DAPR date as suggested.
ENA	Considers jurisdictions should be able to prescribe the start of the forward planning period. Considers the publication date needs to be on a jurisdictional basis due to the fact that networks have different planning drivers and rely on up to date seasonal data to finalise planning forecasts. (p. 2)	Noted. As above.

Stakeholder	Issue	AEMC response
Ergon Energy	Does not support the forward planning period for the DAPR beginning on the date one day after the DAPR date. Jurisdictions should also be able to prescribe the start date of the forward planning period. If no such date is specified, the default date should be the beginning of the financial year, 1 July. (p. 6)	Noted. As above.
Energex	Does not support the forward planning period for the DAPR beginning on the date one day after the DAPR date. Preference is for the forward planning date to be specified in jurisdictional legislation (similar to the DAPR publication date). If no such date is specified in the jurisdictional legislation, suggests the default date be 1 July. This accords with current Queensland reporting arrangements and efficiently aligns the planning period cycle into regulatory years (consistent with the AER QLD Distribution Determination). (pp. 1, 3-4)	Noted. As above.
Energex	Suggests that any intervening period arising between the end of a planning period and the publication of a new DAPR should be dealt with in a similar manner to distribution determinations (refers to clause 6.11.3). (p. 6)	This change is not necessary given that DAPRs will be published annually for a minimum five year forward planning period. It is therefore unlikely that there will be an intervening period as suggested.
Clean Energy Council	Concerned that the Commission has removed the requirement for certification of the DAPR at the executive level. Consider that while there may be structural reasons for DNSPs to argue against this, DNSPs should also be willing to be held accountable for their investment decisions. (p. 3)	We continue to believe that existing regulatory mechanisms and incentives are sufficient to ensure that DNSPs deliver robust, high quality DAPRs in line with the rules. See section 6.4 for a summary of previous discussions on this matter.
Schedule 5.8		
Aurora Energy	Considers there may be a potential duplication of reporting as a result of the rule change. Note that much of the information required in the DAPR is also required by the AER in the draft Regulatory Information Notice (RIN) used for monitoring Aurora's compliance with its draft determination. As a consequence, Aurora would be required to present	The AER's RIN is intended to focus on collecting relevant cost and expenditure information from DNSPs to assist it in its monitoring and enforcement requirements. As the DAPR would also provide information on forecast system limitations and potential solutions, the DAPR would support the information available under the RIN. We note

Stakeholder	Issue	AEMC response
	a single set of base data in at least two ways to meet its regulatory obligations. Note that this duplication will be resource intensive and potentially result in a reduction in transparency as a result of the existence of two versions of the same information. (p. 2)	that the AER supports the DAPR reporting requirements as a means of providing transparency and accountability to DNSPs actions, thereby assisting it in its regulatory and enforcement functions. In addition, the routine publication of DAPRs is likely to reduce the need for similar information to be obtained from DNSPs via other regulatory mechanisms in the future.
ENA	Considers DNSPs will experience significant implementation and ongoing costs associated with: unnecessary duplication of reporting requirements in the DAPR which are already provided for in RIT-D reports. Suggests several clauses be removed, for example, S5.8 (b)(2)(vi), (c)(4), (c)(5), (d)(6), (d)(7), (e), (g), (h), (i) and (l)(1), as they include information already provided for in RIT-D reports. (p. 2)	See section 6.4.2 for further discussion on this matter. Comments on specific schedule 5.8 reporting requirements are also set out below.
Energex	Concerned by the onerous information requirements of the DAPR. Considers a number of requirements in schedule 5.8 will result in duplicate reporting and significantly increase the size of the DAPR. Queries the intent of these clauses and requests the AEMC consider the costs associated with producing this data and remove unnecessary and redundant reporting. (p. 2)	Noted. As above.
Energex	S5.8(a)(5): Energex currently does not report this in its Network Management Plan (NMP) and would assume that this would require energy and demand forecast to be reported. (pp. 6-10)	The final rule includes a transitional rule which provides that a DNSP is not required to include in its first DAPR the information specified in schedule 5.8(a)(5) where this information was not required to be reported under jurisdictional electricity legislation applicable at the time the previous report was prepared. See clause 11.50.4(a).
Energex	S5.8(b)(2): Energex suggests the AEMC consider replacing (i) ‘transmission-distribution connection points’ with ‘bulk supply substations’. A bulk supply substation connects with the transmission and sub-transmission network. (pp. 6-10)	The definition of transmission-distribution connection point is sufficiently broad to cover bulk supply substations. We recognise that DNSPs operating in different jurisdictions often use terminology to refer to the same or similar assets. Our preference is to ensure that the terms used in the rules, and their definitions, are broad enough to capture these differences.

Stakeholder	Issue	AEMC response
Ergon Energy	S5.8(b)(2)(ii): Ergon Energy does not currently produce information on sub-transmission lines. This provision will require Ergon to implement new systems, which are both time-consuming and costly. Ergon presently provides an exceedance report for sub-transmission line segments. (p. 7)	Clause 5.13.1(d)(1) requires DNSPs to prepare forecasts of maximum demands covering the forward planning period for (among other things) sub-transmission lines as part of the distribution annual planning review. Schedule 5.8(b)(2)(ii) then requires DNSPs to report this information in their DAPRs. Sub-transmission lines have been included within the scope of the annual planning review and DAPR because these assets, and the activities associated with them, are likely to materially affect future performance and reliability of a distribution network. On the basis, it is important that the specified information is collated and reported.
Ergon Energy	S5.8(b)(2)(v): Ergon Energy does not presently differentiate between summer and winter firm capacity. For practical purposes, the difference between summer and winter firm capacities is negligible. (p. 7)	While the difference between summer and winter firm capacities may be negligible in some jurisdictions, this may not be the case in all jurisdictions. In addition, where the difference between summer and winter firm capacities is negligible, reporting on both should not add significant costs.
Energex	S5.8(b)(2)(vi): Energex does not currently report this in its NMP and this requirement will require it to initiate system changes which are both time consuming and costly. Energex suggests that this information would only be relevant where there are emerging limitations and then it would be used in the RIT-D process for substations and feeders. As such, Energex suggests that the AEMC consider removing this requirement. (pp. 6-10)	The requirement for DNSPs to provide information on peak load, including on the number of hours per year that peak load is expected to be reached, provides important context to non-network providers, including demand side management solution providers, on the potential opportunities available for investment. Schedule 5.8(b)(2)(vi) clarifies that DNSPs would only be required to provide an 'estimate' of the number of hours per year that peak load is expected to be reached. We understand that DNSPs would be likely to have access to the metering data required to be able to report this information and therefore do not consider this requirement should add significant costs.
Ergon Energy	S5.8(b)(2)(vi): Ergon Energy is able to provide summer and winter peak loads, but it is not possible to provide the number of hours per year that 95 per cent of peak load is expected to be reached with our present systems. As noted above, implementing new systems will be time-consuming and costly. (p. 7)	Noted. As above.

Stakeholder	Issue	AEMC response
Energex	S5.8(b)(2)(vii): Energex does not currently report on this in its NMP and notes that it would be unable to do so for distribution feeders but can supply this information for zone and bulk supply substations. (pp. 6-10)	Schedule 5.8(b)(2)(vii) is not applicable to primary distribution feeders. This provision requires DNSPs to report on power factor at times of peak load for transmission-distribution connection points, sub-transmission lines and zone substations only.
Ergon Energy	S5.8(b)(2)(vii): Ergon Energy does not currently report this in its Network Management Plan. We would only be able to provide this information for zone and bulk supply substations. (p. 7)	Noted. As above.
Energex	S5.8(b)(2)(ix): Energex does not currently report this in its NMP and notes that this requirement will require Energex to initiate costly system changes to capture this information. (pp. 6-10)	Information on the generation capacity of embedded generating units is a key input into the production of accurate load forecasts. Under industry best practice, we would expect DNSPs to have access to this data and to be able to report it in their DAPRs without significant costs. However, a minor amendment has been made to schedule 5.8(b)(2)(ix) to clarify that DNSPs are only be required to report on the generation capacity of 'known' embedded generating units.
Ergon Energy	S5.8(b)(2)(ix): Data on the generation capacity of embedded generating units is not separately reported at present. However, it is taken into account in the demand forecasts. Ergon Energy would need to implement a new system to ensure data can be reported as required. (p. 7)	Noted. As above.
Energex	S5.8(b)(5): Energex suggests the AEMC consider adding unbalanced loads to this list. For example, the presence of disturbing loads such as harmonics. (pp. 6-10)	While schedule 5.8(b)(5) specifies a number of key network parameters, we recognise that other power quality issues may take on greater significance in certain locations. For clarity, this provision has been broadened to include "the quality of supply to other Network Users (where relevant)".
Ergon Energy	S5.8(b)(5)(iv): To provide forecasts of factors affecting ageing and potentially unreliable assets, Ergon Energy will need to implement, at least, a two-stage program. Firstly, to create an interface between network load forecasts and correlate it with ageing and unreliable	Publication of the information required under schedule 5.8(b)(5)(v) is important as a means of providing transparency around the factors which may have a material impact on the network. A catastrophic failure of aging assets has the potential to lead to widespread outages,

Stakeholder	Issue	AEMC response
	assets. Then to transfer adjusted (or corrected) load forecasts into the capital augmentation programs. (p. 7)	particularly in urban areas. It is therefore appropriate that reporting on these assets is included within the scope of the DAPR. To clarify that only descriptive (as opposed quantitative) information would be required, the clause has been amended in the final rule.
Energex	S5.8(c)(1): Energex would not be able to report the month and year but rather the season and year. (pp. 6-10)	Schedule 5.8(b)(5)(iv) has been amended to clarify that DNSPs may provide an estimate of the months (plural) and year when reporting the timing of a system limitation. DNSPs who currently provide this information by season will be able to report by season by specifying the relevant months.
Ergon Energy	S5.8(c)(1): Ergon Energy cannot provide timing by month and year. This is currently provided by season (e.g. summer period) to reflect the nature of our network. We suggest deleting the reference to “month and year” from this clause. (p. 7)	Noted. As above.
Energex	S5.8(c)(3): The information that is intended to be captured under this clause is already reported under joint planning documentation because it is the TNSP that picks up the emerging limit. Energex therefore suggests that this clause be deleted to avoid unnecessary duplication of reporting and increased compliance costs. (pp. 6-10)	Schedule 5.8(c)(3) requires DNSPs to report on the impact of a system limitation identified on a sub-transmission line or zone substation, on the capacity at transmission-distribution connection points. We recognise that the provision of this information may require input from a TNSP. However, it is appropriate that this information be reported under schedule 5.8(c) given that the information relates to emerging limits identified by a DNSP on a distribution network.
Energex	S5.8(c)(4): Energex suggests that reporting this information would be a duplication of information already available under the RIT-D process and for Energex may result in an additional 2000 pages (50 RIT-D projects x 40 pages each) being added to the DAPR. Currently Energex’s NMP is 1200 pages, therefore it is strongly recommended that this clause be deleted to reduce unnecessary compliance costs. (pp. 6-10)	A key objective of the DAPR is to provide sufficient information to allow non-network proponents to consider, and where appropriate develop, alternative solutions to address potential system limitations. By requiring DNSPs’ to publish their initial views on possible solutions which may address forecast system limitations, non-network providers will be provided with a valuable early indication of potential investment opportunities in the forward period. Schedule 5.8(c)(4) has been amended to clarify that only a brief discussion on the types of potential solutions must be provided.

Stakeholder	Issue	AEMC response
Energex	S5.8(c)(5): Energex suggests that reporting this information would be a duplication of information already available under the RIT-D process. If Energex were to report on this in the DAPR, it would require Energex to initiate system changes, which are both time consuming and costly. If the system could not be automated to capture this data, Energex estimates that it would need to engage one to two additional employees to capture and analyse this information for the DAPR. Energex therefore suggests that this clause be deleted in the interests of reducing DNSP's business costs. (pp. 6-10)	Information on the potential for reductions in load to defer or avoid the need for network investment is likely to be of significant interest to non-network providers, particularly embedded generators and demand side management solution providers. While the provision of this information may initially impose compliance costs on some DNSPs, these will be outweighed by the benefits of providing non-network providers with greater transparency around potential investment opportunities. Importantly, this information is only required to be published where a system limitation has been forecast to occur.
Ergon Energy	S5.8(c)(5): Deferrals of system limitations by 12 months, based on an estimated reduction in forecast load, requires a sophisticated data management and forecasting system. In addition, depending on the level and type of constraints, deferral of a major project by 12 months based on an estimated load reduction (which may after 12 months, fail) will put at risk the network and supply to customers. (p. 7)	Noted. As above.
Ergon Energy	S5.8(d)(1): Ergon Energy suggests inserting "based on 4/3 planning criteria (75 per cent utilisation of feeder normal cyclic rating)" at the end of this clause. (p. 7)	The DAPR reporting requirements are intended to allow DNSPs to maintain their existing network planning and forecasting methodology. Therefore, in order to recognise the differences in design planning criteria underpinning different networks, S5.8(d)(2) has been amended to provide some flexibility in the definition of an overloaded primary distribution feeder. Reference to "100% of normal cyclic rating" in the final rule has been qualified by: "or other utilisation factor, as appropriate".
Energex	S5.8(d)(2): Energex suggests that the AEMC should reconsider the requirement to report on the primary feeders that are forecast to exceed 100% of its normal cyclic rating. Energex's notes that normal planning practice is to load distribution feeders up to a utilisation factor to accommodate one feeder being out of service. The number will vary but will not be 100%. Energex suggests that '100% of normal cyclic rating' be replaced with '75% of its normal cyclic rating'. Energex's	Noted. As above.

Stakeholder	Issue	AEMC response
	currently reports on this 75% in its NMP. (pp. 6-10)	
Ergon Energy	S5.8(d)(2): It is normal planning practice to load distribution feeders up to a utilisation factor that accommodates one feeder out of service. Therefore, the number will not be 100 per cent. “100% of its normal cyclic rating” should be replaced with “75% of its normal cyclic rating”. (p. 7)	Noted. As above.
Energex	S5.8(d)(6): Energex suggests that reporting this information would be a duplication of information already available under the RIT-D process. Further, Energex suggests that it is unclear why this information would need to be reported in the DAPR. In order to meet this requirement, Energex would have to initiate system changes, which are both time consuming and costly. Energex therefore suggests that this clause be deleted. (pp. 6-10)	Reporting on potential solutions to address overloaded primary distribution feeders provides important context for non-network providers in considering whether potential investment opportunity exists. DNSPs are only required to report on primary distribution feeders for which a DNSP has prepared forecasts of maximum demands under 5.13.1(d)(1)(iii) and which are forecast to experience an overload. Therefore, we do not consider that this requirement will add significant additional costs. In addition, to ensure the drafting is consistent with schedule 5.8(c)(4), schedule 5.8(d)(3) has been amended to refer to 'types of potential solutions' rather than 'technically feasible options'. DNSPs would not be expected to have undertaken detailed analysis on the potential solutions to address a system limitation at this stage in the planning process. DNSPs would, however, be expected to have at least an initial view on the types of solutions which may address the overload (for example, local generation, demand side management).
Ergon Energy	S5.8(d)(6): Ergon Energy does not currently report on this information in its jurisdictional NMP. To meet this requirement, Ergon Energy will need to implement system changes that are costly and time-consuming. (p. 7)	Noted. As above.
Ergon Energy	S5.8(d)(7): It is difficult to forecast overloads at the primary distribution feeder level. To report 12 months’ potential variations in forecasting at this level, Ergon Energy will need to develop a sophisticated data	Under industry best practice, it is likely that DNSPs would regularly identify and plan for overloaded distribution feeders. However, we note that DNSPs are only required to report on those primary distribution

Stakeholder	Issue	AEMC response
	management and forecasting system and will require additional resources. (p. 8)	feeders for which a DNSP has prepared forecasts under 5.13.1(d)(1)(iii) and which are forecast to experience an overload. As noted above, information on any overloaded primary distribution feeders would enhance the ability of non-network proponents to identify feasible opportunities for embedded generation and demand management.
Energex	S5.8(d)(7): Energex suggests that this clause requires the DNSP to report on partial RIT-D information and queries if this is the AEMC's intent. The DAPR should not result in duplicate reporting with the RIT-D and this clause should be removed. (pp. 6-10)	As above. In addition, this clause requires the reporting of information on overloaded primary distribution feeders irrespective of whether or not they fall within the RIT-D process.
Energex	S5.8(e): Energex suggests that this information is already contained in the RIT-D process documentation and should therefore be removed. Should the AEMC wish to keep this clause (which may add up to thousands of additional pages), Energex suggests that the DAPR should not result in duplicate reporting and a DNSP should only be required to include a link to its website where the information can be easily obtained. (pp. 6-10)	Clause 5.17 of the final rule outlines the RIT-D project specification and assessment requirements for each project to which the RIT-D applies. The objective of the RIT-D documentation is to provide specific, detailed information on DNSPs' assessments of these projects. The inclusion of a high level summary within the DAPR of the RIT-D assessments undertaken in the preceding year allows the outcomes of the planning process to be captured in an accessible format, in a central location. To avoid any doubt that only key, high level information is required to be provided, a number of minor drafting amendments have been made to schedule 5.8(e).
Ergon Energy	Notes that many of the requirements relating to the RIT-D duplicates information already available under the RIT-D process (S5.8(e)). For information that is available elsewhere, considers a specific reference to that source is sufficient. (p. 8)	Noted. As above.
Energex	S5.8(g): Energex suggests that this information is already contained in the RIT-D process documentation for augmentation projects and if it were required to attach the RIT-D and planning documentation to the DAPR, the volume of the DAPR would increase significantly. Currently, Energex's Regulatory Test Project Approval Reports are approximately 50 pages in length. Energex suggests that only refurbishment and	Schedule 5.8(g) requires DNSPs to report on all committed investments that are to address a refurbishment or replacement need, or an urgent and unforseen network issue, and which have an estimated capital cost greater than $2 million. The objective of this requirement is to further increase transparency of the planning process by making available a specified level of information in respect of

Stakeholder	Issue	AEMC response
	replacements that are not the subject of RIT-D should be reported. (pp. 6-10)	projects which fall outside the RIT-D process. To avoid any doubt that only summary information is required to be provided, a number of minor drafting amendments have been made to schedule 5.8(g).
Energex	S5.8(h) and (i): Energex is unclear of the perceived benefit of including this information in the DAPR. Energex currently publishes the information required under S5.8(h)(1) and (i)(1), however the information required under (2) would be more problematic as there may be commercially confidential information that cannot be made available. Energex suggests a better approach would be to publish a list of approved planned investments. This list would then be part of the RIT-D list. Energex further suggests that under (h)(3) and (i)(3), if only the approved RIT-D projects are required to be listed then the contact details will already be provided as part of the RIT-D consultation process. (pp. 6-10)	The objective of schedule 5.8(h) and (i) is to provide transparency around the activities undertaken by DNSPs under the joint planning process. A number of minor drafting amendments have been made to ensure the requirement is reflective of its intent. In addition, this clause requires the reporting of information on investments planned under the joint planning process irrespective of whether or not they fall within the RIT-D process.
Energex	S5.8(l)(1): Energex suggests that the requirement to publish this information in the DAPR would result in duplicate reporting because this information is already contained in the RIT-D process documentation. Energex suggests that the AEMC consider removing this clause. (pp. 6-10)	The provision of information under schedule 5.8(l) allows the outcomes of DNSPs planning activities, particularly those directly supported by the demand side engagement strategy, to be captured in an easily accessible format, in a central location. This provides transparency around the outcomes of DNSPs demand side engagement activities, and should promote the continued development of demand side activities. Further, inclusion of a qualitative summary of non-network options that have been included in the past year is unlikely to add significant cost.
Clean Energy Council	In respect of schedule 5.8(b)(2), considers that, while the number of hours in which peak demand occurs is important, the times of day in which the peak is forecast to occur would inform crucial decisions made by generation technologies such as solar photovoltaic or co-and tri-generation. For this reason, time of day should also be recorded in the DAPR. Timestamp data is usually obtainable from SCADA records of demand and power factor and therefore its extraction should be simple and able to be provided at a low cost by DNSPs with SCADA	Noted. However, at this stage in the rule change process we do not consider it is appropriate to include new information within schedule 5.8 without undertaking further consultation with stakeholders. For this reason, we have not made the change suggested by the CEC.

Stakeholder	Issue	AEMC response
	systems in place. Suggests that where SCADA systems are not in place, estimates of the time of day would suffice. (p. 3)	
Clean Energy Council	In respect of schedule 5.8(m), considers the requirement to report on investment on metering and information technology systems is minimalistic given the crucial role these systems will play in the future design of distribution networks. Considers the DAPR should reflect longer term requirements for planning and investment in these technologies. (p. 4)	Requiring DNSPs to report on recent and planned investments in metering and information technology systems is important given the potential impact these technologies may have on network performance and demand side participation. However, we note that reporting beyond the required five year minimum forward planning period would be beyond the scope of the DAPR. Interested parties would be free to approach DNSPs to seek additional information on any aspect of the DAPR. To this end, the contact details for a suitably qualified staff member to whom queries on the report may be directed will be available on each DNSPs website.
Energex	S5.8(m): Currently, Energex does not report on this type of information in its NMP. Energex is unclear why the AEMC thinks the DAPR should include this information and what the benefit of reporting to the AER would be. (pp. 6-10)	Noted. As above.
Energex	S5.8(n): Energex suggests this clause be removed. Energex does not do regional plans because Energex's distribution area is in one region. Further, the overlay of maps that this clause requires is duplicate reporting because the information is already contained in other sections of the DAPR. (pp. 6-10)	Publication of regional development plans will assist non-network providers and other potential investors to efficiently identify the location of forecast system limitations and potential opportunities for investment. These plans will also provide useful information to communities and increase the transparency of the planning activities undertaken by DNSPs on a regional basis. Given that DNSPs would be likely to have the capability to produce a map(s) of their networks, we do not consider that this requirement should add significant cost.
Energex	Notes that distribution networks generally specify the rating of equipment (lines, cables, transformers) in Amps or MV.A. Forecast loads are generally specified in Amps or MV.A (with also a breakdown of the MV.A figure into its MW and MVAR components). The DAPR requirements do not seem to specify the units of measure which need to be used in reporting. However, under S5.8(c)(5)(iii), for example,	Schedule 5.8(c)(5)(iii) has been amended such that, where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, DNSPs would be required to include in the DAPR the estimated reduction in forecast load in MW "or improvements in power factor" needed to defer the forecast system

Stakeholder	Issue	AEMC response
	there is reference to 'the estimated reduction in forecast load in MW needed to defer the forecast system limitation'. Considers a reference to MW only could be seen as precluding power factor correction as a solution to network limitations. Suggests that this reference should be to MV.A not MW, or not be specific about the units at all. For example, 'the estimated reduction in forecast load needed to defer the forecast system limitation'. (p. 5)	limitations.
Energex	Suggests a more appropriate definition for primary feeders is: "A primary distribution feeder means a distribution line connecting a sub-transmission asset to either other distribution lines that are not sub-transmission or LV lines, or to distribution assets that are not sub-transmission or LV assets." (p. 5)	The definition of primary distribution feeder is based on the functionality of the assets rather than specific voltage levels. This approach is appropriate and sufficiently broad to cover all the intended assets. In respect of the view held by some stakeholders that only "significant" feeders be reported within the DAPR, we have made a minor drafting amendment to ensure the final rule is consistent with the broader requirements of the annual planning review. Clause 5.13.1(d)(1)(iii) requires DNSPs to prepare forecasts covering the forward planning period of maximum demands for primary distribution feeders "to the extent practicable". The final rule therefore clarifies that DNSPs are only required to report on those primary distribution feeders for which a DNSP has prepared forecasts of maximum demands under 5.13.1(d)(1)(iii) and which are forecast to experience an overload.
Essential Energy	Considers the definition of 'primary feeders' is demanding in that it leads to a large volume of information collation, assessment and reporting which would be unlikely to lead to improvements in network planning outcomes or project expenditure needs. Consider a more realistic outcome could be achieved by qualifying that these reporting requirements are applicable to 'significant' primary feeders, or where a constraint or a consequential nominated (substantial) minimum level of investment is required. Suggests a 'significant' primary feeder could be defined as those originating from a zone substation with a form capacity or 10MVA or more, and/or with a peak load greater than 2/3MVA. (pp.1-2)	Noted. As above.

Stakeholder	Issue	AEMC response
Other		
Energex	Does not support removing ability for AER to grant an exemption or variation to the proposed annual reporting requirements. Inclusion of this clause would not result in inconsistency with regard to annual reporting across jurisdictions because the circumstances in which the AER would grant such an exemption or variation would be limited. Notes that a DNSP would only ever initiate such an application where it is clear that the DNSP cannot meet the requirement or where the cost of providing the information would clearly outweigh the benefit. Further suggests that inclusion of such a clause would prevent any future unnecessary rule changes or derogation should a DNSP be unable to meet a reporting requirement. Suggests that the AEMC should reconsider including this clause in the final rule. (p. 2)	While it may be appropriate in some circumstances for the NER to provide some flexibility to cater for differences in local circumstances, the inclusion of a broad exemption clause is not the best means of providing that flexibility. Having considered the detailed comments provided in submissions in relation to the schedule 5.8 reporting requirements, several minor amendments have been made to ensure the final rule is appropriate and fit for purpose for all DNSPs. These amendments are set out in section 6.3.
Ergon Energy	Believes the AEMC should reconsider its position on the ability for DNSPs to apply or exemptions or variations to the annual reporting requirements. Notes that complying with some of the DAPR requirements will necessitate changes to current processes and require additional resources. Consider a DNSP would only apply for an exemption/variation where the DNSP cannot meet a specific requirement, or the costs of providing information outweigh the benefits. In addition, the AER would only grant an exemption where the DNSP has sufficiently justified their position. (p. 7)	Noted. As above.
Essential Energy	Reaffirms belief that the AER should have the ability to grant an exemption or variation to the content of the DAPR. Considers this is particularly important during transition from jurisdictional to national reporting, and until a DNSP has systems in place to comply with the more onerous national requirements. (p. 2)	The final rule provides DNSPs with a minimum period of six months from commencement of the rule before being required to publish a DAPR. In addition, DNSPs will have an additional period of time between publication of this final determination and commencement of the rule to prepare for compliance with the new arrangements. We consider this is an appropriate transitional period which removes the need to provide for exemptions or variations to the reporting requirements during the move to the national framework. With that

Stakeholder	Issue	AEMC response
		said, the final rule includes a number of transitional provisions in relation to several of the DAPR reporting requirements. See clause 11.50.4 of the final rule.
Demand side engagement strategy		
5.13.1 Demand side engagement obligations		
Essential Energy	Considers the requirement to publish the demand side engagement document no later than nine months following commencement of the rule is problematic in that the DSES will need to be developed to align with the RIT-D which is also required to be published nine months after the rule commences. Given the dependency that exists between the timing of the DSES and the RIT-D, requests clarification as to how the conflicting requirements are to be managed. (p. 2)	To the extent that the demand side engagement strategy and RIT-D are linked, the demand side engagement document can be amended and updated by DNSPs at any time, outside of any formal process under the rules. In addition, publication of the draft RIT-D and RIT-D application guidelines should provide DNSPs with a level of information sufficient to understand the new regulatory requirements and to feed these into the demand side engagement document, as relevant.
Energex	Notes draft clause 5.13.2(g) requires a DNSP to publish their demand side engagement document no later than 9 months after the date of the commencement of the rule. Suggests this would result in the AER RIT-D, RIT-D Application Guidelines and DNSP demand side engagement document being published at the same time. Suggests that aspects of the AER's RIT-D and Application Guidelines will affect the contents of the demand side engagement document and therefore clause 5.13.2(g) should be amended so that this document is required to be published after the publication of the AER's documentation. (p. 12)	Noted. As above.
Schedule 5.9		
Victorian DNSPs	Note that schedule 5.9(e) requires a DNSP's demand side engagement document include: an outline of the criteria that a potential non-network provider is to meet or consider in any offers or proposals. Do not consider the drafting is sufficiently clear. In	Schedule 5.9(e) includes a minor amendment in line with the suggestion made by the Victorian DNSPs.

Stakeholder	Issue	AEMC response
	particular, do not consider it is appropriate for DNSPs to outline criteria that a potential non-network provider is "to consider". Propose the following drafting: an outline of the criteria that may be applied by the DNSP in evaluating non-network proposals. (p. 7)	
Clean Energy Council	In respect of schedule 5.9(g) and (h), notes that an embedded generator contracted by a DNSP to provide network support will be subject to a penalty for failing to provide the support on demand, as contracted. Consider the extent of this penalty could deter non-network providers from becoming involved in planning processes. Suggests that the demand side engagement strategy also provide information on the methodology for calculating penalties applicable to non-network providers contracted for support. This will better enable non-network proponents to understand the risks they face and therefore make more efficient investment decisions. (p. 4)	At this stage in the rule change process we do not consider that it is appropriate to include new reporting obligations within schedule 5.9 without further consultation with stakeholders. For this reason, we have not made the change suggested by the CEC.
Joint planning arrangements		
5.14.1 DNSP-TNSP requirements		
Victorian DNSPs	In respect of clause 5.14.1(b), the businesses state they do not understand how or why an interested party should be involved in the joint planning of a declared shared network. Noted that the rule must promote the NEO, but that they are not aware of any reason why the Commission considers this proposal would promote the NEO. (p. 6)	Clause 5.14.1(b) in the final rule mirrors current NER clause 5.6.2(c). The intent of this clause has not been considered in detail in either the AEMC's Distribution Network Planning and Expansion Review or in the context of this rule change. Given that any decision on whether or not to amend or delete this provision should be subject to consultation with stakeholders, no change has been made to clause 5.14.1(b).
5.14.1 Lead party		
ENA	Considers DNSPs will experience significant implementation and ongoing costs associated with: the proposal for DNSPs to complete a RIT-T for all joint planning projects even where such development involves minimal transmission investment. Considers the requirement for DNSPs to implement and maintain compliance with not only the	The joint planning arrangements do not “require” DNSPs to carry out the RIT-T for all joint planning projects. Rather, the final rule allows NSPs to allocate the work required for the RIT-T project assessment process among themselves, in light of the particulars of the matter in hand. While it may be more efficient in some instances for a TNSP to

Stakeholder	Issue	AEMC response
	RIT-D but also the RIT-T is an additional cost not borne by TNSPs. Suggests an amendment to clause 15.4.1(d)(4)(iii) as follows: Where a project is determined to be a RIT-T project, the TNSP is deemed the lead party responsible for carrying out the RIT-T, unless otherwise agreed between the parties.(p. 1)	lead the RIT-T project assessment process, the rules provide flexibility for DNSPs to be the lead party where this is appropriate. See section 8.4 for further discussion on this matter.
Ergon Energy	As stated previously, DNSPs should not be responsible for carrying out the RIT-T. Notes that the RIT-T and the RIT-D differ on a number of aspects and DNSPs are not equipped nor have sufficient resources to undertake both of these tests. Believes that the TNSP should be deemed the lead party, unless otherwise agreed between parties. (p. 5)	Noted. As above.
Energex	Acknowledges the AEMC's attempt to address the regulatory burden on DNSPs but does not support a DNSP being required to undertake a RIT-T for the purposes of joint planning, due to additional costs incurred. While the tests are similar, the RIT-T and RIT-D require different processes, systems and skill sets. Suggests that TNSP is deemed the lead party responsible for carrying out the RIT-T unless otherwise agreed between parties. (pp. 2, 13)	Noted. As above.
Energex	Energex does not support the requirement for DNSPs to undertake a RIT-T on the basis that it would create uncertainty and inefficiency in the distribution planning process due to: (1) differences between the RIT-T and RIT-D. Energex considered it was not prudent for a DNSP to develop the required critical competencies, systems and models to undertake the requirements of the RIT-T; and (2) uncertainties around how to address some of the RIT-T requirements. The uncertainties likely to arise from requiring a DNSP to undertake the RIT-T were sufficient to reconsider the proposed requirements. (p. 14)	Noted. As above.

Stakeholder	Issue	AEMC response
5.14.1 Project assessment process for joint planning projects		
Essential Energy	The assessment process for joint planning should be determined by the nature of the issue to be resolved (eg. RIT-D for a distribution issue and RIT-T for a transmission problem). Considers a realistic approach would be to base the responsibility for project carriage on the nature of the constraint being addressed and the materiality of transmission impact and involvement. In reference to a joint project a $5m limit is not an effective proxy for the true nature of project responsibility. (p. 2)	A single project assessment process (the RIT-T) being applied to all projects which are jointly planned by TNSPs and DNSPs, irrespective of whether the need for investment is driven by a distribution or transmission network limitation, is still considered most appropriate. The final rule does provide some flexibility for the RIT-D to be applied to joint planning projects in certain circumstances. See section 8.4 for further discussion on this matter.
Victorian DNSPs	The draft rule creates an inconsistent approach to the operation of the cost threshold to joint planning projects depending on whether they are subject to the RIT-T or the RIT-D. The businesses propose that the draft rule be amended so that the $5m threshold applies to the augmentation of the network of the lead DNSP if the joint planning project is subject to the RIT-D. (p. 5)	The criterion for determining the appropriate project assessment process to apply to a joint planning project is directly linked to the level of the RIT-T cost threshold as specified under clause 5.16.3(a)(2). However, the approach to, and object of, applying the threshold level under the joint planning process differs from the approach to, and objective of, applying the threshold in accordance with clause 5.16.3(a)(2). In the context of joint planning, where the relevant NSPs determine that the RIT-T project assessment process would be applicable to a joint planning project by virtue of there being a potential credible option with a transmission component greater than $5 million, the outcome of the RIT-T cost threshold assessment under clause 5.16.3(a)(2) will more or less have been determined. Nonetheless, it is important to recognise that the two assessments are separate.
Regulatory investment test for distribution		
5.15.2 Credible option		
Aurora Energy	Considers the drafting of clause 5.15.2 does not reflect the policy intent. Aurora provides an example to demonstrate that although an option may be a "credible option" as defined under 5.15.2, it may not	Noted. However, detailed guidance on the application of the RIT-D cost threshold is a matter more appropriately dealt with by the AER in developing the RIT-D and the RIT-D application guidelines.

Stakeholder	Issue	AEMC response
	necessarily be a solution that would be considered in the general course of network planning. The draft rule would however require that the RIT-D be undertaken, thereby creating an onerous regulatory burden over and above that originally intended. (p. 2)	
Energex	Notes that clause 5.15.2(b)(4), (6) and (7) still refers to "credible option" prior to establishing that option is credible or not. It appears that the AEMC have rectified this for the RIT-D but not the RIT-T. (pp. 15-16)	The clauses in question are relevant to the application of the RIT-T. On the basis that the suggestions are not consequential amendments arising from implementation of the new joint planning arrangements, no changes have been made.
5.16 RIT-T		
Victorian DNSPs	Concerned that transmission-distribution connection points are excluded from the RIT-T without good cause (noted the Commission's clarification in the draft determination that a RIT-T proponent is not required to apply the RIT-T where an identified need can only be addressed by expenditure on a 'connection asset' (as defined in Chapter 10)). Consider there is a need for the rules to provide for a regulatory investment test to be applied to transmission-distribution connection decisions. (pp. 6, 9)	It is not the intention of the final rule to exclude from the RIT-T and RIT-D the assets associated with transmission-distribution connection points which are prescribed transmission services or standard control services. A minor amendment has therefore been made to clauses 5.16.3(a)(6) and 5.17.3(a)(4) to clarify that only those connection assets which do not provide prescribed transmission services or standard control services would be exempt from the RIT-T and RIT-D.
5.17.1 RIT-D principles		
Energex	Reiterates its comment from its previous submission that costs should only have to be quantified where they are material. Notes that the draft rules appear to still require quantification of immaterial costs as per clause 5.17.1(c)(6). (p. 16)	We consider it is important that all applicable classes of costs are considered and quantified by DNSPs. For this reason we have not amended clause 5.17.1(c)(6) as suggested.
AER	Concerned with the level of discretion given to RIT-D proponents on deciding whether market benefits should be considered during a RIT-D assessment. This may result in an inconsistent consideration of market benefits over time and between DNSPs. This would be a violation of one of the RIT-D principles that the RIT-D be capable of being applied in a predictable and consistent manner. Also, in some instances where	Having considered a number of possible approaches to the RIT-D cost-benefit analysis, we are satisfied with a more limited cost-benefit approach being applied which gives DNSPs the option of quantifying market benefits for reliability driven projects. Given the characteristics of the majority of distribution investments, this approach will ensure that the regulatory burden on DNSPs is proportionate to the potential

Stakeholder	Issue	AEMC response
	material market benefits are not considered, the preferred option may not be the option with the highest net economic benefit. RIT-D proponents may therefore be able to game the RIT-D to ensure their favoured option is the preferred option. Suggests that the draft rule be amended to require the quantification of classes of market benefits which are material or which would alter the selection of the preferred option. (p. 4)	benefits of carrying out the cost-benefit assessment. See section 9.4.1 for further discussion on this matter.
ENA	Considers the Commission should confirm in the final determination that quantification of market benefits is optional under the RIT-D and if a DNSPs elects not to quantify market benefits then that decision should not be subject to the dispute resolution process. (p. 2).	Noted. As above.
Energex	The policy position is internally inconsistent with the draft rules: the rule and part of the determination require that the DNSP must consider (but does not have to quantify) market benefits. Notes that the AEMC believes this will provide flexibility in the assessment of market benefits recognising that, in many cases, RIT-D projects will tend to have limited market benefits. Supports this approach. However, note this is inconsistent with footnote 350. Suggests the AEMC confirm in its final determination that quantification of market benefits is optional. Further suggest that if the DNSP chooses not to quantify the market benefits, then this decision is not open to the RIT-D dispute resolution process. (pp. 16-17)	Noted. As above.
Energex	Clauses 5.17.1(c)(4) and 5.17.1(c)(6): suggests that the AEMC should provide further clarity if it requires the DNSP to include the costs of interest on borrowings, establishment fees and prior land costs when referring to 'changes in costs for parties other than the RIT-D proponent due to: differences in capital costs', and 'financial costs incurred in constructing or providing the credible option'. (pp. 23-24)	Clause 5.17.2(c) requires the AER to provide guidance and worked examples in the RIT-D application guidelines on the acceptable methodologies for valuing the market benefits of a credible option under clause 5.17.1(c)(4), and the costs of a credible option under clause 5.17.1(c)(6). It is therefore more appropriate to direct this matter to the AER for consideration during consultation on the RIT-D and RIT-D application guidelines.
Victorian	Consider the draft rule would be improved if it clearly stated that the	This is not a matter for the RIT-D rules. The purpose of the RIT-D is to

Stakeholder	Issue	AEMC response
DNSPs	RIT-D does not require DNSPs to undertake network investment. Consider a similar principle should also be stated in respect of the RIT-T. (p. 8)	identify the investment option which maximises net economic benefits to the market (the preferred option). The RIT-D rules do not explicitly require DNSPs to undertake the preferred option identified in a DNSPs final project assessment report. However, it is not clear why a DNSP would choose not to proceed with the preferred option. We note that investment and expenditure decisions are matters for each DNSP and are subject to regulatory and incentive arrangements set out under Chapter 6 of the NER.
Ergon Energy	Notes the AEMC's statement that the RIT-D "is not intended to test the efficiency of a particular proposed investment per se, nor does it require that a particular investment that satisfies the RIT-D be undertaken". Consider this is a fundamental concept and should be recognised in the RIT-D principles. (p. 4)	Noted. As above.
Energex	Suggests amending the RIT-D principles under clause 5.17.1 to include the statement that: 'The RIT-D is not intended to test the efficiency of a particular proposed investment per se, nor does it require that a particular investment that satisfies the RIT-D be undertaken'. This statement should be a key principle of the RIT-D. Suggests it should not be included on page 174 at the back of a draft determination. It should be a fundamental principle that DNSPs, non-network proponents, the AER and other third parties should be cognisant of. (pp. 22-23)	Noted. As above.
Ergon Energy	Notes that AEMC's proposed definition of 'annual deferred augmentation charge'. Believes the AER's RIT-D application guidelines should address how this charge will be calculated. (p. 9)	We agree that this matter is better addressed in the context of the AER's development of the RIT-D and RIT-D application guidelines. Stakeholders are encouraged to participate in this consultation process and to raise any relevant issue directly with the AER.
Energex	Notes that the AEMC has clarified that connection assets (or a portion of those) which are recovered from all users fall within RIT-D. However, it does not appear that the AEMC has addressed Energex's comment regarding the delays that this may cause for the connecting	As noted in the draft rule determination, where expenditure on an upgrade to the shared network is required to support a new customer connection, and this expenditure will be made by a DNSP and recovered from all users of the network, the upgrade should be within

Stakeholder	Issue	AEMC response
	customer. In circumstances where an upstream augmentation is required to connect a customer, and that upstream augmentation is required to go through the RIT-D process, the connection applicant may not be able to connect for at least 18 months (which is the average planning cycle timeframe for Energex under the Regulatory Test) from the time of application. Not only would such a delay be an issue for a customer, but it may also cause a conflict with the connection timing requirements under Chapter 5A of the Rules. (pp. 19-20)	the scope of the RIT-D. To the extent that there are specific issues in relation to the connection timing requirements under Chapter 5A of the NER, resolving these issues is outside the scope of this rule change.
5.17.3 RIT-D projects		
Victorian DNSPs	Consider the draft RIT-D cost threshold provisions are unclear and may produce unintended consequences. Consider the $5m threshold is an appropriate threshold only if it is applied to the preferred project. Suggest redrafting to: the estimated capital cost of the preferred project is less than $5m. Also disagree that 'commercially feasible and economically feasible' are interchangeable expressions. The draft rule introduces the possibility that actual costs of the preferred option may exceed the threshold, where the estimated costs did not. This could be addressed by amending the provisions relating to the reapplication of the RIT-D (suggested text provided). (pp. 8, 9-12)	It is not appropriate to apply the RIT-D cost threshold to the preferred option on the basis that, at this stage in the planning process, DNSPs should not have identified a preferred option (this is the purpose of the RIT-D). In addition, linking the RIT-D trigger to the preferred option where this is a network option has the potential to cause bias and therefore act as a barrier to non-network options being given due consideration in the project assessment process. In addition, it is not appropriate to apply the RIT-D cost threshold to the least cost option without reducing the RIT-D cost threshold level. The current settings which require that the $5 million cost threshold level be applied to the most expensive potential credible option would subject the appropriate range of projects to a robust economic assessment without imposing an unreasonable burden on DNSPs in respect of the timing and resources required to conduct the process.. Further, we concluded in the draft rule determination that the terms "commercially feasible" and "economically feasible" were interchangeable expressions in the context within which they were used in the proposed rule. These terms may have different meanings and interpretations outside of their use in the RIT-T (and RIT-D). It is for this reason that the AER included guidance in the RIT-T application

Stakeholder	Issue	AEMC response
		guidelines as to the meaning of these terms in this specific context. We expect that equivalent guidance in the RIT-D application guidelines. See section 9.4.2 for further discussion on these issues.
Energex	Considers the requirement to apply the RIT-D cost threshold to the most expensive potential credible option is inconsistent with the intention of having a cost threshold that attempts to address the currently disproportionate regulatory burden on DNSPs. This is because: a) a credible option must be 'commercially feasible' and in practice would involve an NPV analysis, given the draft determination requires the option to also be economically feasible. It is unaware of any proper test for determining commercial feasibility, which would not involve an assessment of costs and benefits; b) the most expensive option is the option that is least likely to be built, particularly as market benefits are not required to be quantified. Notes it has consistently argued that the threshold be amended to 'least expensive' which would address the above concerns and significantly reduce compliance costs for DNSPs by avoiding unnecessary assessments. Unless the threshold is amended, it will be required to conduct the RIT-D on significantly more projects to what it conducted in 2012; and (c) it is not sufficient that footnote 352 in the draft determination limits the threshold analysis to a 'desktop exercise' because: the requirement may be open to dispute, and a DNSP should not be expected to rely on guidance provided in a footnote to a draft determination. If that is the case, then a provision to this should be put in the rules. (pp. 2, 17-19)	Noted. As above.
Ergon Energy	Notes that it has two issues with the proposed approach to the RIT-D cost threshold: (1) that a DNSP will still be required to undertake a mini regulatory investment test prior to the non-networks options stage. Notes the AEMC's suggestion "RIT-D proponent would undertake a desktop exercise supported by credible evidence". In practice, consider this would involve NPV analysis to determine whether an	Noted. As above.

Stakeholder	Issue	AEMC response
	option is commercially feasible; and (2) a DNSP is unlikely to build the 'most expensive' option. Therefore, notes that it is uncertain of the reasoning behind adopting this term to apply to the threshold. Believe the AEMC should re-consider using the term 'least expensive' option. (p. 4)	
ENA	Considers DNSPs will experience significant implementation and ongoing costs associated with: applying the RIT-D to the 'most expensive' option as this would capture all but the smallest projects. This is inconsistent with the intention of having a cost threshold that attempts to address the current disproportionate regulatory burden on DNSPs. If the intention behind the 'most expensive' threshold is to provide an adequate incentive on DNSPs to comply with the rules, the most cost effective solution would be to rely on existing compliance mechanisms under the responsibility of the AER. (p. 2)	Noted. As above.
ENA	Disagrees with the Commission's view that 'commercially feasible' and 'economically feasible' are interchangeable expressions. Concerned that without clarification, DNSPs will adopt materially different interpretations. (p. 2)	The RIT-T application guidelines provide both guidance on, and examples of, what would constitute 'commercially feasible' and 'technically feasible' options. We expect that equivalent guidance will be provided by the AER in the RIT-D application guidelines.
Victorian DNSPs	Note that draft rule would require a project to be subject to the RIT-D process if the project need had been 'reasonably foreseeable'. The effect of this provision is to penalise customers by exposing them to unacceptable reliability issues because an urgent need was not foreseen by the network company. Consider rule should be amended such that the definition of urgent problems do not relate to the foreseeability of the project need. Ensuring delivery of network reliability is the overriding objective. (pp. 8, 12)	It is not the intention that this exemption be used by DNSPs in place of accurate and timely planning practices. Projects required to address an urgent network issue that would otherwise put at risk the reliability of the distribution network but which could have been reasonably foreseen by a DNSP would not be exempt from the RIT-D. We consider that this provision will provide a strong incentive on DNSPs to ensure they undertake comprehensive planning. This in turn should ensure that customers are protected from network reliability issues. See section 9.4.2 for further discussion on this matter.
Energex	Clause 5.17.3(c): suggests that the AEMC should consider adding an additional subclause to what will be deemed urgent and unforeseen so that it will include those projects which are required to be implemented	Noted. As above.

Stakeholder	Issue	AEMC response
	to meet a reliability standard that would otherwise be breached if the project was subject to the RIT-D process. (p. 24)	
Ergon Energy	The AEMC has not adequately dealt with amending the draft rule from 'required to be operational' to 'required to be commenced'. Considers the requirement to be operational is not workable in practice (given majority of investments will take longer than six months to be operational) and would not capture projects that would need to commence earlier than the time taken to complete the RIT-D process to ensure reliability and system criteria are met. Would like the AEMC to re-examine this issue. (p. 9)	We continue to believe that the requirement for an investment to be operational within six months of the problem being identified in the definition of 'urgent and unforeseen network issue' is appropriate given the circumstances and types of projects intended to be captured by the provision. It is intended that this exemption be used rarely and only where the need for investment results from unanticipated and extenuating circumstances such as extreme weather. It is not intended that the exemption be used by DNSPs in the place of accurate and timely planning practices.
5.17.4 RIT-D procedures: screening for non-network options		
Energex	Two issues with the screening for non-network options stage: (1) considers the RIT-D process map set out in Figure 9.1 and the rules do not reflect the same process. Notes the process map suggests that a draft project assessment report is not required to be published for projects where a notice or non-network options report has been published but the estimated capital cost of the preferred option is under $5 million. Clause 5.17.4(n) does not appear to reflect this suggestion. Seeks clarity as to the correct process; and (2) suggests it is unclear if the purpose of the notice is for information purposes only. Concerned that third parties may raise issue with the notice under the misapprehension that it is published for consultative purposes. Energex suggests that the AEMC consider amending the rules so that it is clear the notice is for information purposes only. (p. 21)	To clarify, the final rule provides that a DNSP would be exempt from having to publish a draft project assessment report where: (1) the RIT-D proponent has made a determination that there will not be a non-network option that is a potential credible option (or forms a significant part of a potential credible option) under clause 5.17.4(c) and has published a notice under clause 5.17.4(d); and (2) the estimated capital cost of the proposed preferred option is less than $10 million. The notice required under 5.17.4(d) is for information only.
AER	Concerned that the RIT-D procedures encourage RIT-D proponents to only look at pure non-network or network options and not options which combine both types of investment. Considers the rule should be clarified to state that during the initial screen for non-network options, the RIT-D proponent should look at whether a non-network option is a	A minor drafting amendment has been made to clause 5.17.4(c) to clarify that a RIT-D proponent is not required to prepare and publish a non-network options report if it determines "on reasonable grounds" that there will not be a non-network option that is a potential credible option, "or forms a significant part of a potential credible option", for the

Stakeholder	Issue	AEMC response
	potential credible option or can form part of a potential credible option. Where is could form part of a potential credible option, a non-network options report would need to be published. (p. 5)	RIT-D project to address the identified need.
AER	Supportive of the RIT-D procedures giving greater focus to the consideration of non-network options. However, considers that, as drafted, the screening process may not ensure an adequate assessment of non-network options as a RIT-D proponent is not required to consult prior to making a determination. Notes the presence of demand side engagement obligations on DNSPs but expresses concern that these may not ensure a RIT-D proponent engages with non-network proponents to ensure they have the necessary information to make an assessment of whether a non-network options is a potential credible option. Proposes that the rules be amended to require that if a RIT-D proponent concludes that a non-network option is not a potential credible option, then, in addition to publishing their finding, they must notify all non-network providers on their register of the conclusion and then allow one month for submissions on that conclusion. As part of this, DNSPs would be required to provide information about the technical characteristics of the need and its basis for concluding why a non-network solution would not be a potential credible option. If that consultation finds that a non-network option is a potential credible option, a non-network options report must be published. (pp. 4-5)	The non-network options screening test has been designed to ensure that DNSPs prepare and publish a non-network options report in the instance a DNSP is uncertain as to whether or not a non-network option will be a potential credible option to address the identified need. To ensure this is clear, we have made a minor change to clause 5.17.4(c) such that a DNSP must determine "on reasonable grounds" that there will not be a non-network option that is a potential credible option to address an identified need. Where a DNSP does not have reasonable grounds to make such a determination, it would be required to prepare and publish a non-network options report. This should encourage DNSPs to engage with non-network providers early in the planning process in order to gather necessary information or evidence to support any later determinations under clause 5.17.4(c).
5.17.4 RIT-D procedures: non-network options report		
ENA	Considers DNSPs will experience significant implementation and ongoing costs associated with: significant delays from identifying project limitations to commission due to protracted RIT-D assessment and dispute timeframes. ENA members do not support a four month consultation period on non-network options as is disproportionate to other consultation periods in the rules. Notes that is also expected that due to a greater number of potential parties that can a dispute, DNSPs	The consultation period on the non-network options report must be sufficient to allow for: (1) interested parties to provide submissions on the content of the report; and (2) potential non-network providers to consider, develop and potentially propose viable non-network options. The final rule amends the period of consultation on the non-network options report specified in clause 5.17.4(h) from four months to a

Stakeholder	Issue	AEMC response
	will incur costs for every project that is delayed. (p. 2)	minimum period of three months.
Victorian DNSPs	Support rules in relation to non-network options: the draft rule provides a better method for streamlining the RIT-D where non-network options are not credible. However, exception is the four month consultation period for submissions to the non-networks option report. Consider the proposed period is excessive when compared to the distribution consultation procedures which allow for 30 business days (for example, cl.6.16(c)). (p. 13)	As above. In addition, we do not consider that the 30 business day consultation period provided for in the distribution consultation procedures under clause 6.16(c) is an appropriate benchmark. Clause 6.16(c) specifies the consultation period to be provided by the AER in relation to making, developing or amending any guidelines, models or schemes, or in reviewing any values or methods. Consultation on the non-network options report by DNSPs serves a different purpose.
Ergon Energy	Does not support a four month consultation period for non-network options as this is disproportionate to other consultation periods specified in the NER. Further, suggests that the rule be amended to allow RIT-D proponents to adopt a staged consultation approach to the non-network options report (if desired). This would enable DNSPs to manage their risk by minimising the information they are required to prepare in the first instance. Ergon Energy cites its current process for consultation under the regulatory test as an example. (pp. 4-5)	Noted. As above.
5.17.4 RIT-D procedures: reapplication of the RIT-D		
Energex	Notes three issues in relation to reapplication of the RIT-D: (1) suggests that a DNSPs assessment as to whether it must reapply or not reapply the RIT-D should not be subject to the RIT-D dispute resolution process. The AER has the power to independently review a DNSPs reapplication assessment as part of its monitoring and enforcement role of the NER. Also concerned that if reapplication was subject to dispute this would inevitably result in further project delays, particularly where reapplication became an issue well outside the period (i.e. months/years) after which the original RIT-D was conducted; (2) suggests that the AEMC should consider the reapplication of the RIT-D is not required where a project is urgent or where the additional delay caused by any reapplication would result in	The final rule has been amended to clarify that, in determining whether a RIT-D proponent needs to reapply the RIT-D in accordance with clause 5.17.4(t), the AER must have regard to (among other things) whether the RIT-D project is required to address a network issue that, if not addressed, is likely to materially adversely affect the reliability and secure operating state of the distribution network, or a significant part of that network. A RIT-D proponent's decision to reapply the RIT-D would not be open to dispute under the RIT-D dispute resolution process set out under clause 5.17.5. However, DNSPs would be required to comply with the provision or else risk being in breach of the NER.

Stakeholder	Issue	AEMC response
	the DNSP being unable to meet its reliability standards. (p. 22)	
Ergon Energy	Questions whether a DNSPs decision to apply/reapply the RIT-D is subject to the dispute resolution process. The NER already provides the AER with sufficient power to independently review a DNSPs reapplication. Accordingly, a DNSP's decision should not be subject to dispute. (p. 5)	Noted. As above.
AER	Supports inclusion of the draft rule requiring the reapplication of the RIT-D, but considers that the rule as drafted may not deal well with the circumstances where the material change is a change in the demand forecast which delays the identified need arising. In this case it may not be appropriate to reapply the RIT-D immediately. On this basis, suggests the draft rule be amended to include that where a material change in circumstance is a delay in the identified need, then the RIT-D proponent should wait until the identified need arises again before reapplying the RIT-D. This would ensure that the new assessment would consider any new credible options which have arisen since the first application of the RIT-D. Notes that while outside the scope of this process, a similar provision should be introduced for the RIT-T. (p. 5)	The final rule clarifies that a material change in circumstances may include, but is not limited to, a change to the key assumptions used in identifying (1) the identified need described in, and/or (2) the credible options assessed in, the final project assessment report.
Ergon Energy	Seeks AEMC's view on what may constitute a 'material change'. For example, would this occur only when there is a major change in the scope of the RIT-D project? (p. 9)	Noted. As above.
5.17.4 RIT-D procedures: exemption from draft report		
AER	In respect of clause 5.17.5(s) which provides for a RIT-D proponent to discharge its obligation to publish a final project assessment report separately, the AER considers the $20 million threshold may be too high as distribution projects above $10 million tend to be major projects and should be subject to their own final report. A more	Noted. However, we consider that the $20 million threshold is appropriate as a means of managing some of the compliance costs on DNSPs in respect of reporting under the RIT-D process. It is important to note that DNSPs are only likely to use this exemption in limited circumstances. This is because the dispute resolution process will only

Stakeholder	Issue	AEMC response
	appropriate threshold for this clause is $10 million. This is unlikely to impose an onerous regulatory burden as it is not likely to capture a large number of discrete projects. (p. 5)	commence once a final project assessment report has been published, irrespective of whether it is published as a standalone document or within a DAPR. Therefore, by waiting to include a final project assessment report as part of a DAPR, a DNSP may risk potential delays to a project where the timeframes are not closely aligned.
Other		
AER	In respect of clause 5.6.6AA (which provides that, for non-reliability driven RIT-T projects, the AER may, on written request by a TNSP, make a determination as to whether the preferred option set out in the project assessment conclusion report satisfies the RIT-T). The AER notes it would not support the introduction of an equivalent provision for the RIT-D. However, in principle there is no reason why this provision should only apply to the RIT-T. (p.6)	We have not included a provision equivalent to current clause 5.6.6AA in the RIT-D rules. Given the current economic regulatory framework, a determination by the AER on whether a preferred option set out in a RIT-D final project assessment report satisfies the RIT-D would have little practical effect. See section 10.4.3 for further discussion on this matter.
Aurora Energy	Regarding possible inclusion of a provision to allow the AER to make a determination as to whether a preferred option set out in the final project assessment report satisfies the RIT-D: considers the inclusion of such a provision would be beneficial given the proposed change to S6.2.2(3). It would provide a degree of certainty that capex forecast for a project that has been determined to satisfy the RIT-D will be accepted by the AER as prudent and efficient. (p. 3)	Noted. As above.
Dispute resolution process		
5.17.5 Dispute resolution general		
Victorian DNSPs	The businesses support the reinstatement of the provisions which would allow the AER to grant exemptions from the dispute process. Do not consider this would amount to the AER adopting the role of network planner. Also consider it is unclear whether a DNSP would be able to invoke the urgent and unforeseen provisions in relation to a dispute. The advantages of including the provision substantially	The circumstances in which the AER may grant an exemption from the dispute resolution process are adequately dealt with in other provisions of the final rule. In addition, it would not be appropriate to require the AER to determine the need for a particular project to proceed. For these reasons, the final rule does not provide the AER with the ability to grant exemptions from the dispute resolution process. It would not

Stakeholder	Issue	AEMC response
	outweigh any disadvantages. Also note that if the Commission's reasoning is correct, the provision will be redundant but its inclusion would have no adverse effects or consequences. (pp. 15-16)	be good regulatory practice to include such a provision in the rule, simply as a backstop. See section 10.4.1 for further discussion on this matter.
Energex	Concerned that the scope of matters that can be disputed and the scope of parties that can raise a dispute remains too broad. Suggests the approach has the potential to increase project delays and costs to DNSPs due to the increased risk of lengthy and protracted disputes. Also potential for some third parties being able to use the dispute resolution process by strategically delaying to raise issues which could have been addressed with the DNSP prior to the final report being published. (pp. 2-3)	The final rule provides sufficient safeguards to protect against the risk that the dispute resolution process may be used inappropriately by some stakeholders in certain circumstances. See section 10.4.1 for further discussion on this matter.
Energex	Maintains its position that unless the results of the final project assessment report diverged significantly from the draft project assessment report, parties should not be allowed to raise a dispute in relation to any issue that could have been raised during consultation of the draft project assessment report. Concerned that some third parties will be able to inefficiently exploit the scope of the dispute resolution process to delay projects. Understands that the AER can reject frivolous or vexatious claims and supports such an approach. However, notes that it is Energex's experience under the current regulatory test (which is narrower in scope) that it is very difficult for the AER and the DNSP not to engage with any party that wishes to raise a dispute or issue with a project, even where the grounds of the dispute are questionable. In addition to the time taken to complete a RIT-D (up to 24 months), Energex notes that if a dispute is raised, there is the potential that the project will be further delayed for up to another 100 days. In its experience, disputes and issues raised by third parties have delayed projects by up to three years. (pp. 24-25)	As above. In addition and as noted in the draft rule determination, it is appropriate that any stakeholder who may be impacted by a DNSP's decisions under the RIT-D be provided with the opportunity to raise a compliance issue directly with the AER, without being limited in the circumstances in which it may do so.

Stakeholder	Issue	AEMC response
5.17.5 Interested party		
Energex	Energex suggests that the AEMC should define the term ‘adverse market impact’ as per the definition of ‘interested party’ under clause 5.15.1. There should be absolute clarity as to who should be deemed an ‘interested party’ for the purposes of raising a dispute. (p. 25)	This matter is best addressed by the AER in developing the RIT-D application guidelines. We note that the AER will be responsible for determining, in its reasonable opinion, whether a person (including an end user or its representative) has the potential to suffer a material and adverse market impact from a proposed transmission or distribution investment, and is therefore an ‘interested party’ under clause 5.15.1. An amendment has been made to clause 5.17.2(b)(2) for the RIT-D application guidelines to include an explanation of what the AER considers to be “a material and adverse National Electricity Market impact”.
Implementation and transition		
11 General		
Victorian DNSPs	Note that as currently drafted, the rule would require the application of the RIT-T to joint planning projects from the commencement date. Note that if the Commission accepts that transmission-distribution connection augmentations are subject to the RIT-T, then the businesses would be responsible for conducting the RIT-T for these augmentations. On this basis, consider it would highly desirable for the rules to provide a 12 month transition period (consistent with the proposed period for transition to the RIT-D) such that the RIT-T would begin to be applied to joint projects from 12 months after the commencement date. (p. 16)	The final rule clarifies that joint planning projects for which assessment under the regulatory test has commenced as at 31 December 2013 would continue to be assessed under the regulatory test. See clause 11.50.2 (definition of "regulatory test project").
Other issues		
Energex	Energex suggests that the definition of ‘plant’ should be based around significant or mechanical devices such as a generator, transformer or a circuit breaker. Energex does not consider that an overhead wire or an	The references to "plant" as defined in Chapter 10 of the NER have been removed from the local definitions of "distribution asset" and "transmission asset" in clause 5.10.2 of the final rule. In these

Stakeholder	Issue	AEMC response
	underground cable should be included in this definition of 'plant' but should be defined as 'conductors'. Energex seeks further clarity on this issue to remove the need for interpretation of the rules. (p. 17)	definitions, "plant" is intended as a generic term which, when used in conjunction with "apparatus" and "equipment", is intended to encompass all assets relevant to a distribution and transmission system.
Energex	Total capacity: suggests the AEMC should consider amending 'total capacity' to 'Maximum Supportable Load'. Notes that capacity falls into two basic categories – system normal and emergency, and includes network related constraints in addition to individual components. Suggests that reference to system normal would occur whenever consideration is given to 'with all components in service'. This is because the total capacity of individual devices may be different to the "maximum supportable load" due to interconnected network related constraints such as load sharing, voltage stability and discrete network topography. Energex suggests that "maximum supportable load" is different when there is a contingency or when individual component(s) is (are) out of service. Firstly, a higher rating may apply for components remaining in service (on a short-time basis) but secondly, the maximum supportable load may be lowered due to fewer components being in service. The definition should be Maximum Supportable Load system Normal and Maximum Supportable Load Emergency. (pp. 10-11)	The final rule refers to both 'total capacity' and 'firm delivery capacity', both of which are defined under 5.10.2. Together, these terms will achieve the same outcome as that which would be achieved by replacing references to total capacity with references to 'Maximum Supportable Load system Normal' and 'Maximum Supportable Load Emergency'. The change suggested by Energex has therefore not been made.
Energex	Zone substation: suggests the AEMC consider amending the definition of 'zone substation' so that it includes a reference to bulk supply substations. Notes that zone substations connect between the sub-transmission and distribution networks. Bulk supply substations connect between the transmission and sub-transmission network. Further suggests that the AEMC consider including in the definition a category for bulk supply substation. (p. 11)	It is not necessary to refer to bulk supply substations within the definition of zone substation. In addition, the definition of transmission-distribution connection point is sufficiently broad to cover bulk supply substations. We recognise that DNSPs operating in different jurisdictions often use terminology to refer to the same or similar assets. However, as a national rule, the terms and their definitions must be broad.

B Summary of drafting issues raised in submissions to the draft rule determination

The table below provides a summary of the drafting issues raised by stakeholders in their submissions to the draft rule determination. The table, ordered by key sections of the draft rule, sets out the Commission's response to each issue. For ease of reference, the relevant page numbers have been included in the table.

The submissions received are available on the AEMC website at www.aemc.gov.au.

Stakeholder	Issue	AEMC response
Distribution annual planning review		
5.13.1 Scope		
Ergon Energy	5.13.1(b): *The minimum forward planning period for the purposes of the distribution annual planning review is 5 years.*: notes the definition of "forward planning period" is not contained in Chapter 10 of the Rules. Therefore, suggests removing the italics from this reference. (p. 11)	Agree. Drafting change made.
Distribution annual planning report		
Schedule 5.8		
Ergon Energy	Schedule 5.8: (g) *for all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address a refurbishment or replacement need, or an urgent and unforseen network issue as described in clause 5.17.3(a)(i), provide*: notes the draft rule does not have a "clause 5.17.3(a)(i)". Therefore, suggests amending this to "clause 5.17.3(a)".(p. 12)	Agree. Reference has been amended to refer to clause 5.17.3(a)(1).

Stakeholder	Issue	AEMC response
Demand side engagement strategy		
Schedule 5.9		
Ergon Energy	Schedule 5.9: *For the purposes of clause 5.13.1(f), the following information must be included in a Distribution Network Service Provider's demand side engagement document:…*: considers the reference to "clause 5.13.1(f)" should be replaced with "clause 5.13.1(h)". (p. 12)	Agree. Drafting change made.
Joint planning arrangements		
5.14.1 DNSP-TNSP Requirements		
Victorian DNSPs	Considers that, as joint planning arrangements are focused on developing forward looking plans for augmentation, it is not appropriate to define a 'joint planning project' as a project that has been initiated. Consider a similar problem arises in the definition of RIT-D and RIT-T projects. Also note that the term 'project' can be used in one of two ways: to refer broadly to the range of options that may alleviate an identified network issue; or to refer to the preferred solution to address an identified network issue. Refers to 5.17.3(a)(1) as an example of 'project' meaning two different things [(a) and then in (1)]. Recommends the Commission review the drafting to ensure that: the terms 'joint planning project', RIT-T project and RIT-D project are defined appropriately; and the various applications of these terms work as intended and are not open to misinterpretation. (p. 5)	Drafting has been clarified. The definition of RIT-T project and RIT-D project has been amended to refer to "a project the purpose of which is it…", rather than a project "initiated to".
Regulatory investment test for distribution		
5.16 RIT-T		
Ergon Energy	5.16.2(d): *The AER must ensure that there is a regulatory investment*	Agree. Drafting change made.

Stakeholder	Issue	AEMC response
	test for transmission and regulatory investment test for transmission application guidelines in force at all times after that date.: Notes that this clause previously stated: "The AER must develop and publish the first regulatory investment test for transmission and regulatory investment test for transmission application guidelines by 1 July 2010, and there must be a regulatory investment test for transmission and regulatory investment test for transmission application guidelines in force at all times after that date." Does not support the current drafting of the proposed changes as there is no reference to what “that date” might be (ie. 1 July 2010). (p. 11)	
Ergon Energy	5.16.2(g): *For the purposes of paragraph (f), a “ current application "means any action or process initiated under the Rules*…: Suggests deleting the space before “current”. (p. 11)	Agree. Drafting change made.
Ergon Energy	5.16.4(b): *(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent National Transmission Network Development Plan;*: considers reference to “National Transmission Network Development Plan” should be replaced with “NTNDP”. (p. 12)	Agree. Drafting change made.
Ergon Energy	5.16.4(n): *A RIT-T proponent that is a Distribution Network Service Provider may discharge its obligation under paragraph (j) to make the project assessment draft report availably by including the project assessment draft report as part of its Distribution Annual Planning Report*…: notes that “project assessment draft report” has been inconsistently italicised throughout this clause. As this term is no longer contained in Chapter 10 of the Rules, suggests removing the italics from each reference. (p. 12)	Agree. Drafting change made (definition moved to local definitions).
Ergon Energy	5.16.4(v): (*2) a summary of, and the RIT-T proponents response to, submissions received, if any, from interested parties sought under paragraph (q)*.: recommends adding an apostrophe to “proponents” (i.e.	Agree. Drafting change made.

Stakeholder	Issue	AEMC response
	proponent's). (p. 12)	
5.17.1 RIT-D principles		
Energex	Clauses 5.17.1(b) and 5.17.1(c)(5): suggests that the AEMC consider amending these clauses to include the word 'potential' to the term 'credible option' as it appears to have been left out. (p. 23)	Reference to "credible option" is appropriate in the context of clauses 5.17.1(b) and 5.17.1(c)(5) as these clauses relate directly to the RIT-D assessment. Reference to "potential credible option" is only appropriate in the context of the RIT-D processes which occur prior to a RIT-D proponent commencing a RIT-D assessment.
5.17.2 RIT-D guidelines		
Ergon Energy	Consider the draft rule should reference "distribution consultation procedures" rather than "distribution consultation procedure". (p. 9)	Agree. Drafting change made.
5.17.4 RIT-D procedures: reapplication		
Ergon Energy	5.15.3(b): *For the purposes of clause paragraph (a), the cost thresholds for review are the following amounts:* …: recommends deleting "clause". (p. 11)	Agree. Drafting change made.
Implementation and transition		
11.xx.2 Definitions		
Ergon Energy	11.[xx].2: *regulatory test project for a Distribution Network Service Provider means each project specified in the list provided by the Distribution Network Service Provider to the AER under clause 11.[xx].3(a), except any project the subject of a determination under clause 11.[xx].3(e).*: suggests that "clause 11.[xx].3(a)" and "clause 11.[xx].3(e)" should be replaced with "clause 11.[xx].5(c)" and "clause 11.[xx].5(e)", respectively. Reference to the "AER" should also be italicised as it is a defined term under Chapter 10 of the Rules. (p. 13)	Agree. Drafting change made.

Stakeholder	Issue	AEMC response
Ergon Energy	11.[xx].2: *new network investment means has the meaning given to it in the Rules as in force immediately before the commencement date*.: suggests deleting "means". (p. 13)	Agree. Drafting change made.
11.xx.4 Content of DAPR		
Ergon Energy	11.[xx].4: (c) *For the purposes of paragraph (a)(1)(ii), the Distribution Network Service Provider must include*…: reference to "paragraph a(1)(ii)" should be replaced with "paragraph a(2)(ii)". (p. 13)	Agree. Drafting change made.
Other issues		
10 Global definitions		
Ergon Energy	[3] Chapter 10 Substituted Definitions: interested party …: *(d) In Chapter 2, a person including an end user or its who, in AEMO's opinion, has or identified itself to AEMO as having an interest in relation to the structure of Participant Fees*.: recommends inserting "representative" after "its". (p. 12)	Agree. Drafting change made.
5.10.2 Local definitions		
Victorian DNSPs	Consider it would enhance the clarity of the rule and reduce the potential for misinterpretation if all locally-defined terms were distinguishable from undefined terms. Ideally, consider all definitions would be contained in chapter 10 of the rules, and all defined terms would be italicised. (p. 16)	Given the large number of defined terms used in Part B of Chapter 5 (defined terms which are not used in the rest of the rules) we consider it aids the readability of the Rules to keep these as local definition.
Ergon Energy	[17] Various references to clause 5.6.6: *In clause 6A.6.6(e)(13) and 6A.7.6(e)(13), omit "clause 5.6.6" and substitute "5.17.4"*.: questions whether these clauses should be substituted with "5.16.4". Clause 5.17.4 refers to the RIT-D Procedures, while the existing clause 5.6.6 refers to the RIT-T Procedures which are now outlined under clause	Agree. Drafting change made.

Stakeholder	Issue	AEMC response
	5.16.4 of the draft rule. (p. 10)	
Ergon Energy	5.10.2: *non-network provider … non-network options report* …: Notes these definitions are not in alphabetical order. (p. 10)	Agree. Drafting change made.
Ergon Energy	5.10.2: *project specification consultation … project assessment draft report* …: Notes these definitions are not in alphabetical order. (p. 10)	Agree. Drafting change made.
Ergon Energy	5.10.2: *regulatory investment test for distribution application guidelines* …: questions why the definition for the RIT-T Application Guidelines is captured in Chapter 10, yet the definition for the RIT-D Application Guidelines is included in draft rule 5.10.2. (p. 10)	Agree. Drafting change made.
Ergon Energy	5.10.2: *RIT-D proponent means…(a) if the identified need is identified during joint planning under clause 5.14.1(e)(3), a Distribution Network Service Provider or a Transmission Network Service Provider; or … RIT-T proponent means… (a) if the identified need is identified during joint planning under clause 5.14.1(e)(3), a Distribution Network Service Provider or a Transmission Network Service Provider; or* …: Notes the draft rule does not have a "clause 5.14.1(e)(3)". Suggests that these definitions should reference "clause 5.14.1(e)". (p. 10)	The cross reference has been amended to refer to clause 5.14.1(d)(3).
Ergon Energy	5.10.2: *RIT-T project means: …(b) a joint planning project if: (i) at least one potential credible option to address to address the identified need includes*…: Considers the additional "to address" should be removed from this definition. (pp. 10-11)	Agree. Drafting change made.
Ergon Energy	5.10.2: *transmission asset means the apparatus, equipment and plant, including transmission lines and substations a of a transmission system*: The "a" preceding "of a" should be removed from this definition. (p. 11)	Agree. Drafting change made.
Ergon Energy	5.10.2: *zone substation means a substation for the purpose of connecting a distribution network to sub-transmission network*:	Agree. Drafting change made.

Stakeholder	Issue	AEMC response
	suggests inserting “a” before “sub-transmission network”. (p. 11)	
Energex	Clause 5.10.2: Sometimes there are multiple needs to address the limitation. Suggests the AEMC consider the need to pluralise this definition so that it reads as: joint planning project means a project or projects initiated to address a need identified under the relevant joint planning provisions. (pp. 14-15)	We don’t think is necessary as the singular imports the plural.
Energex	Clause 5.10.2: There may be multiple identified needs and the Rules need to reflect this. Suggests that ‘identified need’ be amended to ‘identified need or identified needs’. (pp. 14-15)	As above.
Energex	Clause 5.14.1(d)(1): Sometimes there are joint planning projects which involve a multitude of TNSPs and DNSPs. There may be a need to pluralise TNSP and DNSP under this clause. The AEMC may need to consider amending this clause so that it reads ‘…and to undertake joint planning of projects which relate to either or all networks’. (pp. 14-15)	We don’t think is necessary as the singular imports the plural.
Energex	Clause 5.14.1(d)(3): Sometimes there are joint planning projects which involve a multitude of TNSPs and DNSPs. There may be a need to pluralise TNSP and DNSP under this clause. This clause may need to also state ‘that will affect all TNSP and DNSP networks’ to reflect the above. (pp. 14-15)	As above.
5.11.2 Identification of network limitations		
Aurora Energy	Noted that proposed clauses 5.11.1 and 5.11.2 refer to "Network Service Providers" which may be either TNSPs or DNSPs. However, the headings for these clauses imply they are intended for application to transmission. Consider the inconsistency between the heading and text creates a degree of uncertainty which could be resolved by a change of heading or introduction of an explanatory note. (p. 3)	We do not think it is necessary to make a change as suggested. The heading of clause 5.11.1 and associated text mirror current NER clause 5.6.1. In addition, the heading of clause 5.11.2 in the final rule is neither distribution or transmission specific which is consistent with the text.

Stakeholder	Issue	AEMC response
5.12 TAPR		
Ergon Energy	5.12.2(7): *[Entire clause]*: notes that "replacement transmission network asset" has been inconsistently italicised throughout this clause. As this term is no longer contained in Chapter 10 of the Rules, suggest removing the italics from each reference. (p. 11)	Agree. Drafting change made.
5.18-5.22		
Ergon Energy	5.22(i): *(1) one or more alternative projects which a directed party must consider when applying the regulatory investment test for transmission to potential transmission projects;*...: notes the definition of "potential transmission projects" is no longer contained in Chapter 10 of the Rules. Therefore, suggest removing the italics from this reference. (p. 12)	Agree. Drafting change made.
Chapter 5 structural changes		
Ergon Energy	12] Rule 5.5A: *Omit Rule 5.6, including the heading, and substitute "[Deleted]"*.: suggests that this should be "Omit Rule 5.5A", as Rule 5.6 relates to "Planning and Development of Network", not "Scale Efficient Network Extensions". (p. 10)	Agree. Drafting change made.