REVIEW

Australian Energy Market Commission

# SCOPING AND ISSUES PAPER

## Review of National Framework for Electricity Distribution Network Planning and Expansion

**Commissioners**

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Reference EPR0015: Scoping and Issues Paper

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## About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market and concerning access to natural gas pipeline services and elements of the broader national gas markets. The AEMC is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

## Foreword

The Australian Energy Market Commission has been directed by the Ministerial Council on Energy (MCE) to conduct a review into the current electricity distribution network planning and expansion arrangements in the National Electricity Market with the view to establishing a national framework for distribution network planning and expansion.

The MCE has provided guidance on the characteristics and desired outcomes of the national framework, and the task for the Commission is to develop the detailed design, supported by proposed Rules, consistent with the MCE direction. In doing so, the Review will have regard to previous analysis and consultation undertaken by the MCE and also the recommendations made in the AEMC Final Report to the MCE on the National Transmission Planner Review.

The distribution networks play an important role in facilitating competition and efficient resource use in Australia's electricity markets. This Review comes at a time when the energy industry is undergoing significant changes, including the Australian Government's introduction of the Carbon Pollution Reduction Scheme and the expanded national Renewable Energy Target.

These policies are likely to impact substantially on the investment in, and operation of, the distribution networks, creating new challenges for network planning and the assessment of expansion requirements. A robust national framework for distribution network planning and expansion will enhance the ability of the market to respond to these challenges.

However, it is only one aspect of a wider set of arrangements and reforms addressing these issues and it is important that these issues are addressed in an integrated and co-ordinated manner. Therefore, the Commission will coordinate its analysis across its own work streams and take into consideration the recommendations of the concurrent reviews into Demand Side Participation and Climate Change Policies.

This Scoping and Issues Paper commences the Review. The purpose of this Paper is to seek stakeholders' comments on the scope and key design issues for the national framework. The Commission is particularly keen for views on what aspects of the current jurisdictional requirements should be maintained in the national framework and also what features of the arrangements for transmission planning are appropriate for distribution.

The Commission will provide its final report to the MCE by 30 September 2009. In the current dynamic environment, stakeholder engagement will form a vital component of this Review. The Commission looks forward to receiving your views and submissions.

John Tamblyn
Chairman

# Contents

# Abbreviations

| | |
|---|---|
| ACCC | Australian Competition and Consumer Commission |
| AEMA | Australian Energy Market Agreement |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| ACG | Allen Consulting Group |
| Commission | see AEMC |
| CPRS | Carbon Pollution Reduction Scheme |
| DNSP | Distribution Network Service Provider |
| DSP | Demand side participation |
| DUOS | Distribution Use of System |
| ESCOSA | Essential Services Commission of South Australia |
| MCE | Ministerial Council on Energy |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEMMCO | National Electricity Market Management Company |
| NEO | National Electricity Objective |
| NER | National Electricity Rules |
| NERA | NERA Economic Consulting |
| NERA/ACG Report | NERA Economic Consulting (NERA) and Allen Consulting Group (ACG), *Network Planning and Connection Arrangements- National Frameworks for Distribution Networks*, August 2007 |
| NSP | Network Service Provider |
| NTP | National Transmission Planner |
| RET | Renewable Energy Target |
| RIT-D | Regulatory Investment Test for Distribution |
| RIT-T | Regulatory Investment Test for Transmission |
| RFP | Request for Proposal |
| Rules | National Electricity Rules |
| SCO | Standing Committee of Officials |
| TNSP | Transmission Network Service Provider |

## Summary

The MCE has directed the Commission to undertake a Review of National Framework for Electricity Distribution Network Planning and Expansion (the Review). This Scoping and Issues Paper commences the initial phase of the Review and the purpose of this paper is to elicit comment on the scope of the Review, and to identify and seek views on a range of issues that require resolution in recommending a national framework.

This Paper organises the discussion on the issues by the three key deliverables to the national framework, as specified in the terms of reference. Each chapter starts with setting out the objective for the Review, then a brief description on the current arrangements for both distribution and transmission, before setting out the key issues needing to be addressed.

For the annual planning process, the paper is seeking views on:

- what should be the scope and objective of the annual planning requirement on DNSPs; and
- the appropriate content for the annual planning report.

In relation to designing the project assessment and consultation process – which is referred to as the regulatory investment test for distribution (RIT-D) - for the national framework, the key issues raised are:

- the appropriate scope of projects to be subject to the RIT-D;
- the nature of consultation on possible options;
- what costs and benefits should be recognised and quantified in the assessment; and
- the nature of the decision making criteria to determine the most economic option.

Regarding the other key deliverable of a dispute resolution process, the key issues to be addressed are:

- whether the scope of the dispute resolution process should be limited to the outcomes of the RIT-D; and
- how should the process operate and whether it should be a merits or a compliance review.

Consideration of the interaction between transmission and distribution planning, ensuring the national framework is cognisance of climate change policies and determining the appropriate extent of the distribution activities and services subject to the national framework are also key issues to be addressed under this Review.

Responses to the Scoping and Issues Paper will be of assistance to the Commission in identifying and developing the understanding of the issues that should be addressed. Submissions should be received by **5 pm, Friday 17 April 2009** and should contain the reference "**EPR0015"** in the subject heading. Submissions may be sent electronically to: submissions@aemc.gov.au

or in hardcopy to:

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

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# 1 The Review

Under section 41 of the National Electricity Law (NEL), the Ministerial Council on Energy (MCE) has directed the Australian Energy Market Commission (Commission) to:

- conduct a review into the current electricity distribution network planning and expansion arrangements in the National Electricity Market (NEM); and
- propose recommendations to assist the establishment of a national framework for distribution network planning and expansion (Review).

This Scoping and Issues Paper commences the initial phase of the Review. The purpose of this paper is to elicit comment on the scope of the Review, and to identify and seek views on a range of issues that require resolution in recommending a national framework.

## 1.1 Terms of Reference for the Review

The objective of the Review is to develop recommendations, on the appropriate design of a national framework for electricity distribution network planning. The Commission is to provide the MCE with its final report by 30 September 2009.

The MCE terms of reference states that the national framework for distribution network planning shall include the following:

- a requirement on distribution network service providers (DNSPs) to perform an annual planning process;
- a requirement on DNSPs to produce and make publicly available an annual planning report which has a 5 year planning horizon. At a minimum the annual plan must forecast distribution network constraints;
- a requirement for DNSPs to undertake a case by case project assessment process to identify the most economic option when considering network expansions and augmentations. This process is to be triggered using appropriate thresholds; and
- a dispute resolution process.

The terms of reference also provide guidance on the required characteristics of the national framework, including that:

- DNSPs have a clearly defined and efficient planning process which provides certainty in relation to the approval of network expansion and augmentation to maintain the reliability of the electricity supply to consumers.
- DNSPs develop the network efficiently. This includes addressing a perceived failure by DNSPs to look at non-network alternatives (such as embedded generation, energy efficiency and conservation measures) in a neutral manner when making distribution augmentation assessments.

- Appropriate information transparency to allow:
  - network users, including distributed generators, to plan where best to connect to the network and provide an appropriate regulatory environment to facilitate this;
  - network users to understand how the timing of connection might affect connection charge arrangements, to the extent which connecting users contribute to upstream augmentation requirements; and
  - efficient planning by parties that may offer alternative, more cost-effective solutions to network augmentations to address emerging constraints.
- Ensure a level playing field for all regions in terms of attracting investment and promoting more efficient decisions.
- Reduce the regulatory compliance burden for participants operating in more than one region in the NEM.

The national framework should result in a planning process which is more transparent, will enable participants to engage in the process (i.e., embedded generators and small scale demand management providers) and result in the DNSPs having regard to a wider range of market benefits when considering prospective investments than is currently the case. The MCE has also requested that the Commission seek to achieve consistency, to the extent appropriate, with the electricity transmission planning framework when developing its recommendations and proposed new Rules. The Review will not cover distribution network connections or other network access issues, as these issues are to be progressed by the MCE via a separate process. A copy of the MCE's terms of reference can be found at Appendix A.

## 1.2 Background to the Review

The MCE requested the Commission to undertake this Review after considering a report by NERA Economic Consulting (NERA) and Allen Consulting Group (ACG) titled, *Network Planning and Connection Arrangements- National Frameworks for Distribution Networks* (NERA/ACG Report). This report was commissioned by the MCE Standing Committee of Officials (SCO) in 2007 to provide advice on a national framework for electricity distribution planning, connection and connection charge arrangements.

In MCE SCO's December 2008 policy response to the NERA/ACG Report, MCE SCO considered that further analysis and consultation was required to develop a national framework for electricity distribution network planning and expansion, following a number of developments in the NEM. These developments included: the development of a Regulatory Investment Test for Transmission; the proposed introduction of the Carbon Pollution Reduction Scheme (CPRS) and increased Renewable Energy Target (RET); and the AEMC's Review of Demand Side Participation in the NEM.

Given the recent review on electricity transmission planning, MCE SCO considered it appropriate to direct the Commission to advise the MCE on a national framework for distribution planning and expansion. A national framework for distribution connection and connection charges will be progressed by the MCE separately to this Review with the National Energy Customer Framework.[1]

The Commission assumes the NERA/ACG Report and the MCE's response to the NERA/ACG Report have been read and taken into account by stakeholders prior to considering this Scoping and Issues Paper.

## 1.3 Current distribution network planning arrangements

Currently under Chapter 5 of the National Electricity Rules (NER or Rules), distributors are required to carry out analysis and planning of the future operation of distribution networks. Distributors and the relevant transmission network operators are also required to undertake joint planning on an annual basis. This planning activity is to cover the following 5 year period and take into account forecast loads, future generation and market network services, and demand side developments. While the NER does not require the distributor to publish any periodic planning reports, the distributor is required to advise market participants of any constraints identified in the system and any proposed corrective action. For proposed corrective action options that satisfy the Regulatory Test, distributors are also required to carry out economic cost effectiveness analyses.[2] The NER also requires the distributor to consult with market participants and report on the outcomes of the economic assessment for proposed new assets with an estimated capital cost of more than $10 million.

The arrangements in the NER are supplemented by additional state-based regulatory arrangements set out in jurisdictional legal instruments. The jurisdictional planning arrangements differ significantly, with some jurisdictions being more prescriptive particularly in terms of the information to be reported and requirements to consider non-network options. A summary of the current provisions in each jurisdiction, as well as the relevant provisions of the NER, is provided in **Appendix B**.

## 1.4 Submissions to the Scoping and Issues Paper

Through out this paper are questions and issues upon which the Commission invites stakeholders to comment and provide views. Submissions to the Scoping and Issues Paper are requested by **5 pm, Friday, 17 April 2009**. At this stage, the Commission is particularly keen for views on what aspects of the current jurisdictional requirements should be maintained in the national framework and also what features of the arrangements for transmission planning are appropriate for distribution.

[1] A copy of NERA/ACG's report and MCE SCO's policy response to this report can be found on the MCE website at www.mce.gov.au

[2] The provisions of the Regulatory Test are set out in clause 5.6.5A of the NER.

Submissions should contain the reference "**EPR0015**" in the subject heading. Submissions may be sent electronically to: submissions@aemc.gov.au.

Or in hardcopy to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

## 1.5 Timetable for the Review

The Commission will undertake extensive consultation with all relevant stakeholders throughout the Review, including network planners and operators, retailers, consumer groups and energy user representatives, non-network proponents, distributed generators, regulators, market operators, and policy advisors. We are keen to engage constructively with DNSPs and interested stakeholders throughout the Review and intend to hold a series of workshops in May on the range of options for the national framework.

The timetable for the Review is as follows:

| Stage of Review | Date |
|---|---|
| Release of Scoping and Issues Paper for public comment | 12 March 2009 |
| Close of submissions on Scoping and Issues Paper | 17 April 2009 |
| Commission to hold industry workshops on design of national framework | May 2009 |
| Release of Draft Report and draft Rules for public comment | 18 June 2009 |
| Public forum on Draft Report and draft Rules | Late June 2009. Exact date to be confirmed. |
| Close of submissions on Draft Report and draft Rules | 20 July 2009 |
| Submit Final Report to MCE | 30 September 2009 |

## 1.6 Structure of the Paper

The remainder of this Scoping and Issues Paper is structured as follows:

Chapter 2 – discusses the scope of the Review and the Commission's proposed approach for assessing options for the national framework.

Chapter 3 – discusses the issues relating to the annual planning requirements.

Chapter 4 – discusses the issues relating to the project assessment and consultation process.

Chapter 5 – discusses the issues relating to the dispute resolution process.

Chapter 6 – discusses issues that are common across the areas set out above.

Chapter 7 – summarises the questions and issues outlined in each of the Chapters on which the Commission is particularly seeking feedback.

Appendices – provides the terms of reference for the Review and a summary of the current planning arrangements that apply.

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# 2 Proposed Scope and Approach

The terms of reference for the Review requires the Commission to undertake a specific task, i.e., to design a national framework for how DNSPs conduct their network planning. The terms of reference provides some prescription on the features and desired outcomes of that framework. This Chapter considers the proposed scope of this Review and discusses the approach which the Commission will apply in assessing the options for the national framework.

## 2.1 Proposed Scope

There are two dimensions to consider with respect to the scope of this Review; the aspects of the distribution arrangements that need to be considered under this Review and, within that, the scope of activities and services undertaken by the DNSPs that fall under the national framework.

### 2.1.1 Distribution Issues out of scope

This section clarifies those issues that are considered to be out of scope of the Review. The terms of reference for the Review states that the Review will not cover those distribution network connections and network access issues which are being addressed separately by the MCE.[3] In addition, the Commission considers issues relating to the framework governing revenue determinations, pricing of distribution services and the recovery of network investment are not directly in the scope of this Review.

### 2.1.2 Scope of Distribution Services

An important consideration for the Review is the appropriate scope of distribution services that should be included within the national framework.

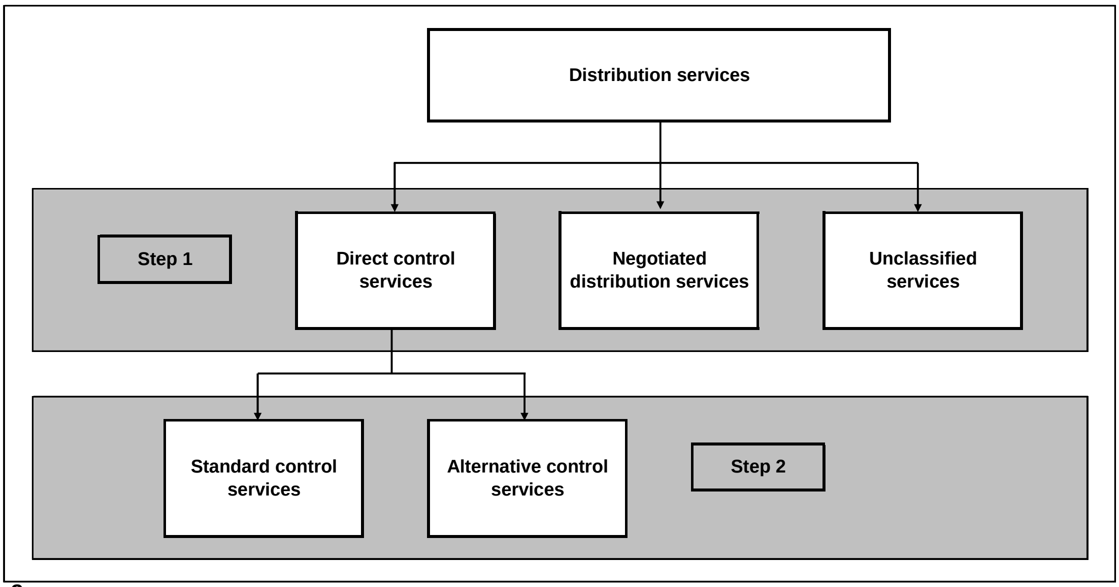
One approach would be to make the classification of services for the national framework consistent with the classification of services determined by the Australian Energy Regulator (AER) when making its distribution determinations.

The arrangements for classifying distribution services are set out in Chapter 6 of the NER (services not classified by the AER are not regulated under the NER). The AER may classify the distribution services as either direct control services or negotiated distribution services. The AER must further classify direct control services as either standard control services or alternative control services (see **Figure 2.1**). Service classification effectively determines two key aspects of the AER's distribution determination:

[3] See MCE-SCO Policy Response, Electricity Distribution Network Planning and Connection – A National Framework for Electricity Distribution Networks, 15 December 2008.

- whether the service should be under a direct price or revenue control, a 'negotiate-arbitrate' framework, or no price or revenue control—that is, the form of control that will apply to the service; and
- whether the costs of providing the service should be recovered by DNSPs through distribution use of system (DUOS) tariffs paid by most customers, or through separate tariffs paid by the individual customer requesting the service.

**Figure 2.1 Distribution Service Classification Process**




[a] NER Chapter 6, Part B.

A question for this Review is whether the scope of the national framework should be extended to include negotiated distribution services and alternative control services (excluding connections). As this issue may differ between the requirements relating to the annual planning report and the project assessment process, this issue is discussed further in the respective chapters of the Paper.

## 2.2 Commission's Approach

In developing its recommendations for a national framework for distribution network planning, the Commission is required to have regard to the National Electricity Objective (NEO) in the NEL. The NEO states:

> 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.[4]

In addition to the NEO, the Commission has developed a set of decision making criteria after taking into account the MCE's terms of reference. These decision making criteria will guide the Commission's approach to the Review and its recommendations. The Commission's proposed decision making criteria for the Review are as follows:

- The extent to which the proposed national framework incorporates the variations in the existing jurisdictional distribution planning arrangements, including how well the framework is able to accommodate variations in jurisdictional distribution reliability standards;

- An appropriate balance between the regulatory burden on DNSPs and the benefits to the broader market;

- Ensuring a level playing field for all regions in terms of attracting investment and promoting more efficient decisions;

- Minimising the regulatory compliance burden for market participants operating in more than one region in the NEM;

- The effectiveness of the proposed annual planning process and annual planning report in identifying non-network solutions to augmentations and encouraging efficient planning by market participants;

- Access to and timeliness of the dispute resolution process; and

- Achieving consistency, to the extent appropriate, between the national framework for distribution planning and the electricity transmission planning framework.

There are a number of differences between transmission and distribution to take into consideration. Distribution augmentations tend to be needed for reliability reasons and are less likely to deliver wider market benefits. Hence this may justify a less elaborate regulatory test for distribution than for transmission. The scale of projects for distribution projects is significantly smaller and proponents of non-network alternatives to distribution augmentations are likely to be less informed or (financially) able to dispute a distribution project.

The distinction between distribution and transmission networks on the basis of assets is not straight forward. Networks have typically evolved in such a way that former transmission assets become distribution assets, and distribution networks serving large load centres frequently contain assets that could equally be classified as transmission or sub-transmission assets. Furthermore, parts of the distribution network often serve as an additional element of redundancy for the transmission network. The Commission will have regard to these differences and the interaction

[4] Section 7, National Electricity Law.

between transmission and distribution network planning when developing its recommendations on the national framework.

The Commission is seeking stakeholder views on:

1. The proposed scope for the Review;
2. Its proposed approach and assessment criteria for the Review; and
3. The interaction between transmission and distribution network planning.

## 2.3 Policy Context for the Review

There are a number of current policy reviews and Rule changes that relate to the arrangements for distribution network planning. The Commission will manage the various interactions between this Review and other work-streams as its conducts its assessment of the appropriate national framework. This Review will incorporate, where relevant, the outcomes of the Commission's Reviews into Demand Side Participation and Climate Change.

The following areas of Commission's work, some of which are cited explicitly in the terms of reference, are relevant to this Review.

### 2.3.1 Review of Demand Side Participation in the NEM

The Commission is currently undertaking a review into Demand Side Participation (DSP) in the NEM. The objective of this review is to determine whether there are barriers or disincentives within the Rules for the efficient uptake of DSP in the NEM. Part of this DSP Review is assessing whether the are any barriers to non-network projects within the current arrangements for distribution network planning. The Draft Report for the DSP Review is due to be released in April 2009.

### 2.3.2 Total Environment Centre Demand Management Rule Change

The Commission is currently considering a Rule change proposal from the Total Environment Centre, which seeks to amend the Rules to facilitate the increased use of demand management in the NEM. On 29 January 2009, the Commission published a draft Rule determination and determined to make a draft Rule on this Rule change proposal, with some modifications. In its draft Rule determination, the Commission decided against creating any favourable bias in the Rules towards non-network alternatives in network service providers' planning processes, as it could result in more efficient network solutions being overlooked.[5]

[5] AEMC, 2009,*Demand Management*, Draft Rule Determination, 29 January 2009,.

### 2.3.3 Review of Energy Market Frameworks in light of Climate Change Policies

The MCE has directed the Commission to undertake a review to determine whether the existing energy market frameworks should be amended to accommodate the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded 20 per cent Renewable Energy Target (RET). This review is to consider both the electricity and gas markets across all states and territories. The outcomes of this review are to provide advice on what, if any, changes are needed to energy market frameworks, including how these changes should be implemented. The 1st Interim Report for this review was released on 23 December 2008. The 2nd Interim Report, which will set out the Commission's proposed options for changes to energy market frameworks, will be published in June 2009.

This Review will be particularly important for the consideration of demand management, as the CPRS and expanded RET will impact on the potential costs and benefits of demand side solutions in the NEM. Also there is a need to ensure that the project assessment process for distribution is consistent with climate change policies and especially whether the process appropriately values carbon costs.

### 2.3.4 Regulatory Test Thresholds and Information Disclosure on Network Replacements Rule change proposal

On 23 October 2008, the Commission made a Rule determination and Rule on the regulatory test thresholds applying to transmission network assets.[6] The effect of the Rule has been to:

- raise the new small transmission network asset threshold from $1 million to $5 million and the new large transmission network asset threshold from $10 million to $20 million;
- provide for a three yearly review of threshold values by the AER; and
- require the following information to be provided on all proposed replacement transmission assets over $5 million in TNSPs' Annual Planning Reports: the purpose of the proposed asset; a list of alternative projects; and the TNSPs' estimated total capitalised expenditure on the proposed asset.[7]

As part of this Rule change, the Commission also considered aligning the revised new transmission network asset thresholds to the thresholds for new distribution network assets. However, while noting the applicability to distribution of many issues in the Rule change proposal, the Commission considered that the appropriate thresholds for distribution should be subject to separate analysis and consultation, particularly as the scope for demand side projects is greater for distribution than for transmission.

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6 *The National Electricity Amendment (Regulatory Test Thresholds and Information Disclosure on Network Replacements) Rule 2008 No. 9*, 23 October 2008.

7 At the time the Rule change proposal was submitted, only network augmentations were subject to information disclosure requirements.

### 2.3.5 Regulatory Investment Test for Transmission

In April 2007, the MCE directed the Commission to conduct a review into the development of an enhanced planning process for the national electricity transmission network (NTP Review). The Commission submitted its Final Report on the NTP Review to the MCE in June 2008.[8] The Commission's Final Report recommended Rule changes to implement a revised Regulatory Investment Test for Transmission (RIT-T), to improve the identification of transmission investment options which maximise net economic benefits. The Commission recommended that the revised RIT-T:

- only apply when the capital cost of investment options exceed $5 million in value, with the exception of urgent or unforeseen investments, investments related to the provision of connection or negotiated services, and transmission projects which only involve replacements;
- amalgamate the reliability and market benefits limbs of the current regulatory test;
- facilitate earlier consultation in the planning process to enable other potential viable non-network options to be identified and assessed appropriately;
- ensure that national market benefits are recognised under the project assessment process; and
- include an additional market benefit category of option value, to recognise the benefits that the proposed project may have on future investments and costs.[9]

In the MCE's policy response to the Commission's Final Report on the NTP Review, the MCE requested that the AEMC progress the proposed Rules for the revised RIT-T under the fast track Rule change process under section 96A of the NEL.[10] The Commission received a formal Rule change proposal from the MCE to implement the RIT-T on 20 February 2009 and has commenced the Rule change process.

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[8] AEMC, 2008, *National Transmission Planning Arrangements Review- Final Report to MCE,* 30 June, Sydney.

[9] Ibid.

[10] MCE, *National Transmission Planning Arrangements: Ministerial Council on Energy Response to Australian Energy Market Commission Final Report,* November 2008, p. 12.

# 3 Annual Planning Requirements

## 3.1 Objective

The MCE has agreed that the national distribution network planning framework should require each DNSP to conduct an annual planning process covering a 5 year forward looking period and produce an annual planning report informing on the planning process. The planning reports would be published publicly and, at a minimum, would set out forecast distribution network constraint information. The objective of this Review is to develop requirements on the DNSPs which would result in a clearly defined and efficient planning process for network investment and support the efficient development of the network. In order to achieve this, the national framework will need to provide appropriate transparency in the DNSPs' planning activities and sufficient information to allow market participants to make efficient investment decisions.

## 3.2 Current planning requirements for DNSPs

Under the Rules, DNSPs are currently required to analyse the expected future operation of the distribution networks and conduct joint planning with TNSPs where appropriate.[11] While the Rules do not require DNSPs to publish any planning reports, DNSPs are required to report to market participants on network constraints and undertake project assessments.[12] DNSPs must also comply with jurisdictional instruments which require each DNSP to prepare an annual planning report.[13] However, the specific requirements vary across the jurisdictions:

- Queensland – the Electricity Industry Code requires DNSPs to produce an annual network management plan covering the next 5 year period. The purpose of the plan is to set out how DNSPs will manage and develop their supply network. The contents of the plan are also set out in the Code and include requirements to outline the demand management strategy, and to report on the historical reliability performance for the previous five years.

- New South Wales – the *Electricity Supply Act* 1995 (NSW) imposes licence conditions requiring each DNSP to prepare an annual demand management plan covering the next 5 year period and including analysis of the cost effectiveness of any demand management strategies. A demand management code of practice sets out in detail the processes and procedures for considering non-network solutions including energy efficiency improvements, load management and embedded generation options.[14] These demand management requirements are

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[11] cl. 5.6.2(a) and cl. 5.6.2(b) of the Rules.

[12] cl. 5.6.2(e) to cl. 5.6.2(h) inclusive of the Rules.

[13] Except in ACT, where there are no additional jurisdictional requirements.

[14] A breach of the code of practice could be considered a breach of the licence conditions.

more prescriptive than any requirements to consider demand management in Queensland, Victoria and Tasmania.

- Victoria – the Electricity Distribution Code requires DNSPs to publish an annual planning report covering the next 5 year period on how the DNSP plans to meet forecast demand and improve reliability. This Code obliges DNSPs to include non-network alternatives in their considerations such as embedded generation or demand management, amongst other things.

- South Australia – the South Australian distributor is required to produce an annual plan covering the next 3 to 5 year period including examining system constraints and forecast loads. The Essential Services Commission of South Australia (ESCOSA) publishes an industry guideline prescribing the reporting and consultation requirements for planning and project assessments. The *Electricity Act* 1996 (SA) also requires the DNSP to investigate and publish results of demand management strategies. As with the provisions in New South Wales, these requirements are more prescriptive than Queensland, Victoria and Tasmania.

- Tasmania – the requirements in Tasmania are similar to those applicable in Victoria. The Tasmanian Electricity Code sets out the requirement for the DNSP to produce an annual plan on how it will meet forecast demand and improve reliability over the next 5 year period. DNSPs are required to include non-network alternatives in their considerations such as embedded generation or demand management.

- Australian Capital Territory – no specific jurisdictional based planning or reporting requirements apply.

Additional information on the requirements in each jurisdiction is outlined in Appendix B.

## 3.3 Current planning requirements for TNSPs

Under the Rules, TNSPs are required to prepare an annual planning report setting out the results of their annual planning reviews, including the results of the joint planning conducted with DNSPs.[15] The Rules prescribe the contents of these planning reports such as details on forecast constraints on the network, proposed augmentations, and assessments of reasonable alternatives to proposed projects. The reports are required to be published by 30 June each year.[16]

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[15] cl. 5.6.2A(a) of the Rules.

[16] The Rules define "publish" as being made available to Registered Participants electronically.

## 3.4 Issues for comment

The planning process and reports should facilitate efficient distribution network investments and maintain the reliability of supply. To this end, the planning reports should provide sufficient information to guide private sector investors to help optimise investment and promote efficient decision making.

In this Scoping and Issues Paper, the Commission is seeking stakeholder comment on the following aspects of the planning report requirements:

- Which network assets and activities should be included in the planning requirements for the national framework?

- What should be the type and level of detail of information to be provided in the planning report?

- How should the planning and reporting process be implemented?

### 3.4.1 What is the scope of network assets and activities?

Planning is required to identify any factors that may affect the future performance and reliability of the network and to propose activities to be undertaken by DNSPs giving consideration to the available options (including non-network solutions). The MCE has determined that the scope of the planning and reporting process would require DNSPs to prepare and publish an annual planning report covering a 5 year forward looking planning period.

The task for the Review is to define the network assets and activities that should be included in the planning process for the national framework. Possible aspects could be:

- developing a framework for determining load forecasts( given that forecasting demand might become more difficult under climate change policies);

- identifying types of potential problems relating to quality of service and transfer capability that could arise from forecast load and new connections and identification of options to address those potential problems;

- meeting jurisdictional reliability and planning standards;

- planning for high stress events;

- defining how the potential for non-network solutions is taken into consideration;

- planning of both augmentation and replacement assets that may affect the quality of service from the shared network to customers (i.e. direct control services);[17]

- managing any implications for the shared network from intermittent distributed generation;

- understanding any impacts of negotiated distribution services on planning activities; and

- understanding how connections might affect the transfer capability of the shared network (noting that the MCE is currently considering the provisions for connection agreements).

In addition, the planning process should also include consideration of the interaction between transmission and distribution planning. Currently under the NER, TNSPs and DNSPs are required to conduct joint planning and TNSPs are to incorporate into their annual planning reports forecast loads provided by DNSPs.[18]

The Review is also assessing whether the planning process should include an assessment of the accuracy of past planning. For example DNSPs could be required to evaluate the robustness of past planning processes by setting out historical performance data and providing explanations for any differences and reporting on their compliance with their requirements.[19]

The Commission is seeking comments on the scope of the planning and reporting process. In particular:

4. In addition to emerging constraints, what other types of potential problems of the distribution network should be included in annual planning reports?

5. How could the interaction between transmission and distribution planning be reflected in the annual planning and reporting process?

6. Should the annual planning report including reporting on work carried out by DNSPs including reporting of actual network performance information and historical data?

### 3.4.2 What should be the type and the level of detail of information to be provided in the planning report?

The annual planning reports will inform the outcome of the DNSPs' planning process under the national framework. The reports should provide sufficient

17 Direct control services as discussed in Chapter 2 of this paper and defined under section 2B of the NEL.

18 cl 5.6.2(b) of the Rules.

19 It is noted that some of the jurisdictional planning provisions incorporate consideration of past performance and historical data as well as compliance reporting.

information transparency to allow network users to identify network investment opportunities, including the timing and location of potential network augmentation and connections. In addition, the reports should provide an appropriate level of detail as well as balance the potential benefits of providing the information with the potential costs of preparing the reports. The specific content requirements of the planning report could include:

- Credible scenarios of demand for next five years;
- forecast of distribution network constraints and other distribution network problems;
- potential solutions to network constraints including results of case-by-case project assessments and public consultations where applicable (refer to Chapter 4);
- information on projects which were not subject to the project assessment process that have been scheduled or are proposed;
- outcomes of the TNSP and DNSP joint planning;
- forecast of distribution network capacity including load forecasts and transmission interface provisions including the extent of surplus capacity at different points in the distribution network; and
- other factors such as adequacy of transmission interchange capacity, general network capacity and summer and winter peak capacity.

It is noted that the recommendations from the NERA/ACG Report included the consideration that the DNSPs include forecast average marginal distribution loss factors in the planning reports to assist stakeholders with calculating the value of investments.[20] The Review will consider whether this should be implemented.

The Commission is seeking comments on the appropriate content of the annual planning report, and especially on:

7. What factors need to be considered to ensure the level of detail of the information provided is useful and appropriate to stakeholders?

8. For the areas that are to be reported on, what specific factors should be considered? For example for emerging constraints, how should emerging constraints be classified and how could they be consistently set out?

9. Should a distinction be made between general information that is publicly available and more detailed information for embedded generators and demand side response proponents?

[20] NERA/ACG, *Network Planning and Connection Arrangements – National Frameworks for Distribution Networks, August 2007*, p. 24.

### 3.4.3 How should the planning and reporting process be implemented?

The Review will advise on how the annual planning process and reporting requirements will be implemented through amendments to the Rules. To consider how this may be achieved, questions of implementation and process will be considered.

The Commission is seeking comments on the implementation of the planning and reporting process. In particular:

10. Would the Australian Energy Market Operator's website be the appropriate central location for the planning reports to be stored and published?

11. What would be the appropriate timeframe for the publication of the DNSP annual planning report (noting the relationship between the timeframe for the publication of the TNSP annual planning report and the DNSP/TNSP joint planning requirements)?

# 4 Project Assessment and Consultation Process

## 4.1 Objective

The national framework will include a project assessment and consultation process which establishes the procedures and criteria to be applied by DNSPs in considering investments. The process, which would be triggered by appropriate thresholds, would require the DNSPs to conduct a robust economic assessment of alternatives and properly assess non-network alternatives in a neutral manner.

The task for the Review is to design this process – which will be referred to as the Regulatory Investment Test for Distribution (RIT-D) – consistent with the outcomes set out in the MCE terms of reference. The new test should be transparent and inclusive of all interested participants and, importantly, be efficient and proportionate.

## 4.2 Current arrangements

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 been varied over time.[21] The Regulatory Test was initially developed by the Australian Competition and Consumer Commission (ACCC) in 1999, and modified in August 2004. This modified test remains in force, and is included in the AER's regulatory guidelines.

The Regulatory Test can be applied differently depending on the primary purpose of the prospective investment. There are two possible limbs:

- Reliability limb: an option that is required solely to meet mandatory requirements (typically reliability requirements) has to be least cost. The comparison is with options which have a clearly identifiable proponent; and

- Market benefits limb: all other options are required to maximise the expected net present value. The comparison needs to be against genuine and practicable alternatives, but is not limited to alternatives that have a proponent.

The Rules state that for any distribution projects the DNSPs must carry out an economic cost effectiveness analysis of possible options to identify those that satisfy the regulatory test.[22] The term "cost effectiveness test" is used in the NER to refer to the reliability limb whereby the lowest cost option of meeting a reliability obligation is selected. For distribution projects above $10 million DNSP's are also required to

[21] A test to ensure that distribution augmentations maximised benefits for customers (the 'Customer Benefits test') was a condition applying to authorisation of the National Electricity Code. In July 1999, this was modified to a 'Regulatory Test', to be applied by DNSPs when considering whether augmentations should proceed.

[22] The current project assessment framework for distributions is set out in NER clause 5.6.2

consult on that analysis and publish a report on the results of the economic cost effectiveness test.

The existing jurisdictional requirements vary (see Appendix B). Both New South Wales and South Australia require a case-by-case assessment of all proposed augmentations to evaluate the possibility of non-network solutions. In each case this requires an initial 'reasonableness' test to filter situations where non-network options have a greater likelihood of being economic. Where this is satisfied the DNSP must issue a 'request for proposal' (RFP) inviting proposals from demand management proponents. Both States provide detailed instructions on what should be included in a RFP and the process for evaluating the options identified. Also only New South Wales and South Australia describe the evaluation process that distributors should follow in considering projects. Both States stipulate that the test should rank all options based on the total annualised cost to the distributor of providing system support plus the net effect on system losses.

## 4.3 Issues for comment

In this Scoping and Issues Paper, the Commission is seeking comments on the following elements to the project assessment framework:

- What should be the scope of projects subject to the RIT-D process?
- What are the requirements for identifying and consulting upon the range of options?
- What costs and benefits should be recognised and quantified in the assessment?
- What should be the decision-making criteria used to determine which option passes the test?

These issues are inter-dependent. For example, the appropriate threshold may depend upon the extent of assessment required under the test. An important consideration in designing the new RIT-D is achieving consistency with the transmission arrangements, and the Commission is keen for stakeholder views on which aspects of the RIT-T could be suitable for distribution. Chapter 5 discusses the appropriate dispute resolution process for the national framework.

### 4.3.1 Scope of Projects

There are two aspects to consider in designing the appropriate thresholds to trigger a RIT-D assessment:

a) the types of investments that should be required to undertake the test; and

b) the cost threshold applicable to determine whether which projects are subject to the test.

The current regulatory test applies to new distribution assets which are augmentations (which is defined as works to enlarge a network or to increase the capability of a network to transmit or distribute active energy). The questions to be addressed in this Review are whether that definition is sufficient and also whether proposed investments such as negotiated services, reconfigurations and projects which combine augmentation and replacement expenditure, should also be subject to the RIT-D.

Another issue is the appropriate boundary between transmission and distribution projects. From time to time there are augmentations to the distribution network that require related works to the transmission network. In some instances, options for addressing projected limitations on the transmission network may involve transmission and distribution alternatives. In addition, some DNSPs have dual function assets.[23]

These projects raise issues in terms of the appropriate project assessment process. The approach proposed for the RIT-T is that projects are classified by the original intent of the augmentation. For example if there is a need to augment to relieve a distribution constraint which ultimately causes a transmission augmentation, then that project be assessed purely under the distribution project assessment process. Likewise, dual function assets would be assessed under the distribution process. We are keen for views on whether such an approach should apply to distribution.

#### 4.3.1.1 Threshold to trigger project assessment

The threshold that is to be applied to the scope of projects to trigger the case by case evaluation will be a key component of the national framework. Any prospective project below that threshold would not be required to undertake the project assessment process.

The reason for having such thresholds is to avoid imposing a regulatory requirement that creates a compliance cost that may not be offset by the benefits created. Accordingly, the thresholds should reflect an implicit assessment of the point at which the potential benefits of performing the mandated activity is outweighed by its costs. For each threshold the potential benefits are savings on network augmentations, either through the identification of more efficient network solutions or through deferral of the augmentation by means of a non-network solution. The costs will depend upon the assessment procedures and requirements.

Currently the threshold is based upon the estimated costs of the preferred option. In its recommendations to the MCE, NERA/ACG recommended that projects requiring an estimated capital expenditure of more than $500,000 be subject to an economic cost benefit assessment, and projects estimated to cost more than $2 million, be

[23] Dual function assets, are those assets which are owned and operated by the DNSPs and which operate in parallel, and provides support, to the higher voltage transmission network (see Chapter 10 of NER).

subject to public consultation and issue a request for proposal from potential providers of non-network solutions.[24]

The approach of applying defined cost thresholds has the potential risk of being too simplistic and of not capturing all the necessary projects. Relatively low-cost investments can have far-reaching market impacts in some instances. Alternatively an initial screening process or objective criteria could be used. However with these approaches, issues emerge as to how to specify the screening criteria and which party should apply the criteria.

For the RIT-T, the Commission recommended a cost threshold of $5 million and that the threshold should be applied to the most expensive option which is both technically and economically feasible. For distribution, an initial screening process to determine whether a project has more than minimal market benefits may be useful.

In addition, there is the risk of DNSPs potentially escaping the project assessment process by breaking projects up into smaller components to avoid triggering the thresholds. A potential way of dealing with this issue is at the specification of options to solve a constraint stage. At this stage guidance could be required to ensure the whole cost of the solution is derived, thus avoiding the issue of a solution being broken down into multiple related small works.

The Commission is seeking comments on the design of the project assessment process. In particular:

12. What types of investments should be subject to the project assessment process?

13. What are the appropriate thresholds to trigger the project assessment process?

14. Should the thresholds be indexed in accordance with CPI or subject to a periodic review?

#### 4.3.1.2 Identifying and consulting upon options

To ensure that DNSPs undertake the economic cost benefit assessment of alternative projects in a fully informed manner, they must conduct the test in a transparent environment. A requirement to seek a formal RFP from potential providers of non-network solutions is a means of achieving this.

At present there are no obligations under the NER for DNSPs to issue a RFP, however project assessments in New South Wales and South Australia are required to identify non-network solutions for all projects over $200,000 and $2 million respectively. Currently, TNSPs are required to issue a RFP for investment projects greater than $10 million. The proposed RIT-T requires all projects over $5 million to undertake a project specification consultation process.

[24] NERA/Allens, Network Planning and Connection Arrangements – National Framework for Distribution Networks, August 2007, p. 28.

The RFP process is the formal means for a non-network provider to submit an alternative option to the prospective investment.

The information and timeline provisions in a RFP process are of crucial importance, because if non-network proponents do not have sufficient information and time their proposals will have a greater chance of being unsuccessful; and repeated and costly failure will ultimately undermine the credibility of the process. The issue of timelines is also important to DNSPs in that the RFP process needs to fit in with their broader network planning processes.

Given the requirements for undertaking a RFP process, there may be justification for including a higher threshold for the project assessment process. For projects under the higher threshold, DNSPs could be required only to undertake an economic cost-benefit assessment (and not required to issue an RFP or consult on alternative options).

Another issue to note in relation to potential non-network proponents providing non-network solutions is the guarantee of implementation when required. For example, if a non-network solution is provided, but not delivered when required the DNSP is impacted negatively. DNSPs typically require comfort by requiring a contractual arrangement to avoid being exposed to such events. This potentially raises issues in relation to the timing/schedule of a RFP process, in that if a non-network solution proves to be the desirable option to relieve a constraint, there may a need conduct a separate process of contractual negotiation between a DNSP and non-network proponent.

The Commission is seeking stakeholder comments on the RFP process. In particular:

15. What factors should be considered in a RFP process and how should this be specified in the Rules compared to AER guidelines? Including:

    - what defines a credible option?
    - what information is needed to enable market participants to raise alternatives?
    - how long should the consultation take place?
    - should an RFP process include elements to deal with the potential issue of DNSPs seeking assurance from non-network proponents for the performance of a non-network option?

### 4.3.2 Identification and quantification of costs and benefits

One of the outcomes to be achieved by the national framework is a requirement for DNSPs to conduct a robust economic assessment of investment options. This is to determine the most efficient investment to address the network problem. Such a test requires an assessment of the various costs and benefits associated with the range of options. The question for this Review is to determine the appropriate range of costs and benefits and the criteria for determining which costs and benefits are assessed for each project.

Currently DNSPs are required to apply a "cost effectiveness" test, which refers to the reliability limb of the regulatory test. This least cost assessment assumes that all of the augmentations are driven by prescriptive reliability obligations. However, there are reasons why this may not be the case in all circumstances. For example, certain projects may lead to savings in distribution projects or could increase the transfer capability for embedded generators, leading to lower dispatch costs.

The design of the project assessment process must ensure that such benefits are appropriately identified and assessed. This must be balanced against the risk of requiring the DNSPs to conduct assessments, which could be detailed and complicated, for projects that do not deliver market benefits. There could be concerns about broadening the scope of distribution investment assessments on the basis that it would complicate and delay the process of meeting their mandatory reliability obligations.

In addition the project assessment test should reflect the nature and type of benefits arising from distribution investments. One issue to consider is whether the current classes of market benefits adequately capture the relative benefits of underground compared to overhead lines.

In its recommendations on the RIT-T, the Commission proposed a system where the RFP stage is expanded to include consultation on the potential range of market benefits associated with each option and also required the TNSPs to quantify market benefits which they considered to be material, against an objective and transparency basis. The Commission also recommended maintaining the concept of proportionality to determine the appropriate degree of detail and rigour to be applied in the assessment of the particular project option.

Such objective and transparent criteria could be adapted to distribution investments in order to avoid imposing an unnecessary analysis burden on DNSPs. There is a need to ensure that the new arrangements do not unreasonably increase planning timescales. However, this is a different question to whether the workload of a DNSP in assessing network investment should increase. Requiring the DNSPs to commit more resources to the analysis of investment options could be appropriate provided that such an increase is practical to implement and proportionate to the overall improvement in the investment decision making process.

For the RIT-T, the Commission also recommended that the Rules contained greater prescription on the classes of market benefits. The reason for doing so was to ensure appropriate market benefits are identified and quantified. Also, it ensured that the TNSPs could not "cherry pick" only those costs and benefits that validated their proposed projects.

The Commission recognises the need for consistency in the range of costs and benefits DNSPs must take into consideration when making their planning decisions. The Review must determine the appropriate range of benefits and costs associated with distribution investment, especially benefits from distributed generation. An important dimension to this is the need for the distribution project assessment process to be consistent with climate change polices and ensure that environmental benefits are treated and quantified appropriately.

Another consideration in determining the range of market benefits is the application of deterministic jurisdictional reliability standards. A possible market benefit could be the increased reliability above the minimum required under the deterministic standards. An approach to valuing reliability benefits may need to be developed in order to distinguish between options which have the same costs but differ in the amount (and timing) over which they exceed the minimum standards.[25]

The Commission is seeking stakeholder comments on the application of the project assessment process. In particular:

16. What is the appropriate list of costs and benefits associated with distribution projects, and should that list be mandated in the NER?

17. How should the range of benefits to be quantified under the project assessment process be determined?

18. How can the project assessment process ensure that environmental benefits are appropriately treated and quantified?

### 4.3.3 Decision making criteria to determine most economic option

The MCE has requested that the national framework include an economic assessment of options. Therefore the project assessment process should include an assessment of market benefits when appropriate. This will require changing the framework for selecting the best option from a least cost approach to a cost benefit decision approach.

Therefore a key issue is whether the current limbs of the regulatory test should be combined into a common test, whereby the same assessment is applied irrespective of the primary reason for that investment. Alternatively, the project assessment process could maintain different limbs and objective and transparent criteria is applied for determining which prospective project goes through which assessment criteria.

Under a cost benefit approach, the most economic option would be the option which maximises the net present value of benefits minus costs. If there are no market benefits to be assessed then the cost-benefit assessment would become a least cost assessment. Therefore, there may be no need to maintain a separate limb for least cost assessments. Instead a common cost benefit criteria could be developed which

[25] The variations in reliability benefits could relate to a) the period of time for which different options meet the mandatory standard – different options may satisfy a given standard for different periods of time; and b)the number of mandatory standards the option addresses. Different options may address a greater or smaller number of discrete mandatory standards.

would permit the DNSPs to apply a least cost assessment in appropriate circumstances.

Consideration of how to apply such a cost benefit criterion is required. Such a criterion would need to be consistent with the mandatory reliability standards. The question is how to design a common test across jurisdictions which have different methods to setting their planning and reliability standards.

The proposed RIT-T addressed the problem by requiring only additional reliability benefits above the mandated level to be quantified and developing a decision Rule whereby mandatory reliability obligations would be met by the option that had the lowest negative net present value.

There is also the question of whether such a criterion is robust enough. There may be cases when a relatively low-cost project might meet a reliability standard, but a more expensive project is available that is expected to meet the standard at lower net cost (i.e. direct costs less market benefits). For example, assume that the first project could meet the reliability standard at a cost of $10 million without generating any market benefits while the second project could have a cost of $100 million but market benefits of $95 million. While the second project would maximise welfare under normal conditions, it could expose the market to the risk that the predicted market benefits might not come to fruition and that the high costs to develop the project might be incurred unnecessarily with the benefit of hindsight.

One way of dealing with such situations may be to impose a decision criterion based on maximising the ***ratio*** of net market benefits to project costs (or, conversely, minimising the ratio of net market costs to project costs). However, this would itself need to be subject to caveats, as presumably both market stakeholders and policymakers would prefer a project with, say, $100 million market benefits and $50 million costs proceeding in place of an alternative project with $20 million market benefits and $5 million costs.

Therefore, it may be most appropriate to treat the application of the assessment process in a similar way to the current application of the Regulatory Test – that is, to require DNSPs to apply the assessment across a range of scenarios and use their judgment to find the most appropriate option.

The Commission is seeking stakeholder comments on the application of the project assessment process. In particular:

19. How should a net benefit test be designed for distribution investments assessments? What are appropriate circumstances where a least cost assessment should be applied, and if so, should the two limbs of the regulatory test be maintained?

20. Is there a need for a more specific decision making criterion compared to the existing regulatory test?

# 5 Dispute Resolution Process

## 5.1 Objective

The MCE has requested that the Commission include a dispute resolution process in its recommendations for a national framework for distribution network planning and expansion. The purpose of the dispute resolution process is to provide a mechanism for market participants to question DNSPs' decision making, and in doing so, provide transparency to DNSPs' decisions and a regulatory oversight on their behaviour. A dispute resolution process also provides market participants with a formal mechanism to obtain decisions on outstanding issues which cannot be resolved informally amongst the disputing parties.

One of the decision making criteria the Commission proposes to use in the development of a national framework is the access to, and timeliness of, the dispute resolution process. The process should also reflect good regulatory practice by being proportionate in its design, so that the costs of undertaking the process reflect its potential benefits. The costs associated with the process should also be efficient and the process itself should be balanced in its treatment of all parties to the dispute.

## 5.2 Current dispute resolution process for DNSPs

Currently under the NER, dispute resolution processes are only available to Registered Participants in relation to the project evaluation reports for new large distribution assets (i.e. projects which will cost in excess of $10 million) or where the project will change the Registered Participant's DUOS charges by more than 2 per cent.[26] Registered Participants and the DNSP are required to negotiate in good faith, and if agreement can not be reached, the dispute resolution process under Rule 8.2 of is triggered.[27] Under this process, if the parties are unable to resolve the dispute through their dispute management systems, the dispute may be referred to the AER appointed Dispute Resolution Advisor and then potentially referred on to the Dispute Resolution Panel, if the Advisor is unable to resolve the dispute. Under the NER, the determinations of the Dispute Resolution Panel are final and binding on the disputing parties.[28] The dispute resolution process under Rule 8.2 is general in nature and is not tailored to the specific types of disputes relating to distribution planning. Also this process is complex and has the potential to be lengthy and costly, particularly if the establishment of a Dispute Resolution Panel is required.

There are currently no formal jurisdictional dispute resolution processes for distribution in any of the NEM jurisdictions.

[26] cl. 5.6.2(i) of the National Electricity Rules.

[27] cl. 5.6.2(j)-(k) of the National Electricity Rules.

[28] cl. 8.2.1(f) of the National Electricity Rules.

## 5.3 Current dispute resolution process for TNSPs

For transmission, only issues relating to new large transmission augmentations (i.e. projects costing more than $20 million) can be disputed. All interested parties are able to lodge a dispute. [29] The dispute process and possible grounds for dispute differ depending on whether the augmentation is labeled as a reliability investment or a discretionary market benefit investment.[30] The scope for disputes is greater for market benefits investments than for reliability augmentations. The AER is responsible for hearing and making determinations on transmission disputes. Determinations by the AER are binding, but can not direct TNSPs as to what they can or cannot construct.

These current arrangements would be replaced following the implementation of the RIT-T. The following changes to the dispute resolution process for transmission have been proposed by the MCE:

- The dispute resolution process should be applied consistently across all relevant prospective investments (i.e. both reliability and market benefit investments) and interested parties should be able to raise disputes in relation to application of the RIT-T assessment for new small and large transmission assets;
- The AER's basis for assessing disputes should be whether the TNSP has complied with the NER and the AER's RIT-T, and not whether the best option has been selected. Therefore, it is proposed that the dispute resolution process be a compliance review rather than a merits review of the TNSP's project assessment;
- The AER should be able to direct the TNSP to amend its analysis in its project assessment report if the AER finds the TNSP has not complied with the Rules or the RIT-T;
- The AER should have the ability to reject disputes immediately if the grounds for the dispute are invalid, misconceived or lacking in substance.[31]

## 5.4 Issues for comment

In this Scoping and Issues Paper, the Commission is seeking stakeholder feedback on the following aspects of the proposed dispute resolution process:

- What should be the scope of issues subject to dispute resolution?

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[29] 'Interested parties' is a defined term in the Rules and is defined for the purposes of Chapter 5 as an end user or its representative who has an interest in network planning and development activities; or has the potential to suffer a material and adverse market impact from the project assessment final report.

[30] The dispute resolution process for transmission is specified in clauses 5.6.6(j)-(n) of the National Electricity Rules.

[31] MCE, 2009, *Regulatory Investment Test for Transmission Rule change proposal,* 20 February 2009. The MCE submitted this Rule change proposal following the MCE's response to the Commission's Final Report on the National Transmission Planning Arrangements Review.

- How should the dispute resolution process operate?
- What should be the outcome of the process?

### 5.4.1 What should be the scope of issues subject to dispute resolution?

The scope of the dispute resolution process in the national framework will be a key consideration. Currently in both distribution and transmission, parties are only able to raise disputes in relation to the project assessment process for new large assets.

The MCE has not specified the scope of the dispute resolution process in its terms of reference. Therefore, there is the potential for the dispute resolution process to be extended beyond the project assessment process undertaken by DNSPs. For example, the dispute resolution process could also apply to elements of the annual planning process undertaken by DNSPs, such as DNSPs' forecasts in their annual planning reports of distribution network constraints, and the projected timing of these constraints.

The scope of the dispute resolution process will also be affected by the threshold for the process. The appropriate threshold for the dispute resolution process will need to balance providing access to the process with the need to ensure that the process is cost effective and delays in investment, particularly straight forward or urgent investments, are minimised. Also it will depend upon the design of the national framework and the level of engagement with participants in the planning process.

There is also the option of having different thresholds for the project assessment process and the dispute resolution process. For example, having a lower threshold for the dispute resolution process in comparison to the project assessment process, could allow parties to provide greater scrutiny of the decisions made by DNSPs in relation to smaller investments. In contrast, having a higher threshold for the dispute resolution process in comparison to the project assessment process, could ensure that only sufficiently material investments are subject to the process.

The Commission is seeking stakeholder comment on the appropriate scope of the dispute resolution process. In particular:

21. Should the dispute resolution process only apply to project assessments undertaken by DNSPs under the regulatory test or should the dispute resolution process also apply to matters arising from DNSPs' annual planning processes?

22. What is the appropriate scale of distribution projects that should be subject to the dispute resolution process? Should the threshold for the dispute resolution process be aligned with the threshold for the project assessment process?

### 5.4.2 How should the dispute resolution process operate?

The dispute resolution mechanism should balance the need to provide appropriate scrutiny and consultation with the need to ensure that disputes can be resolved in a timely and cost effective manner and investments are not unduly delayed.

Currently for distribution, once disputes have been referred to the formal dispute resolution process under Chapter 8 of the NER, parties are able to undertake mediation or seek a non-binding decision from the Dispute Resolution Advisor, before requesting that a final and binding determination be made by the Dispute Resolution Panel. In contrast, under transmission, there are no formal mediation processes available under the NER, with disputes referred directly to the AER for binding determinations.

The appropriate process for the dispute resolution mechanism will depend on the scope and threshold of the disputes which will be heard. A requirement for parties to undertake a formal mediation process prior to the referral of a dispute for a binding determination may allow disputes, particularly smaller and less complex disputes, to be resolved quickly and at low cost. In contrast, for more complex disputes with multiple parties, a mediation process may be ineffectual and result in unnecessary time delays. Therefore, the direct referral of such disputes for a binding determination may be more appropriate.

The appropriate arbiter for the dispute resolution process should be impartial, appropriately qualified, and should have adequate resources to hear disputes. For transmission, the AER is responsible for resolving and making determinations on disputes and is possibly the most appropriate body to undertake this role for distribution. If a mediation process is adopted, an appropriate mediator will also need to be appointed. The appointed mediator should be separate to the body responsible for making binding determinations, to ensure the processes remain impartial.

Currently only Registered Participants are able to lodge a dispute in relation to distribution. In contrast, in transmission a range of parties are able to lodge disputes, including Registered Participants, the AEMC, Connection Applicants, Intending Participants, NEMMCO and interested parties.[32] All parties which may be directly affected by the planning processes of DNSPs should be able to lodge a dispute. Therefore, the Review will consider whether these parties are likely to extend beyond Registered Participants.

Another issue for consideration is the framework for raising a dispute. Currently, disputes can only be opened once the regulatory test process has been completed. One possible criticism of this is that it leaves dispute resolution too late in the planning process and increases the risk of the DNSP having to re-do the project assessment. This could occur if the issue being disputed is the DNSP's selection of credible options. However, a potential disadvantage of including the possibility of raising disputes during the project assessment process is that it would introduce an additional step in the process, which may create unnecessarily delays to investments.

Also, the grounds for raising disputes must be clear under the national framework. For transmission, the issues which can be disputed are set out in the Rules. Disputes

[32] cl. 5.6.6.(j) of the National Electricity Rules.

cannot be raised in regard to matters that the regulatory test treats as externalities and cannot relate to an "individual's personal detriment or property rights".[33]

The Commission is seeking stakeholder comment on how the dispute resolution process should operate. In particular:

23. Who should be able to initiate the dispute resolution process?

24. What process should be followed to resolve disputes and what should be the timing for this process? Should parties be required to undertake a formal mediation process before the dispute is referred for a binding determination? What aspects of the proposed process for transmission should apply to distribution?

25. Who should make binding determinations to resolve disputes? Is the AER the most appropriate body? If a mediation process is used, who should be the mediator for disputes?

26. Should the appointed arbiter have the ability to reject disputes immediately if the grounds for the dispute are invalid, misconceived or lacking in substance?

### 5.4.3 What should be the outcome of the process?

The effect of the dispute resolution mechanism is dependant on the type of dispute resolution process that is adopted. Under the current dispute resolution processes for both transmission and distribution, the decisions of the AER and the Dsipute Resolution are binding, but TNSPs and DNSPs respectively cannot be directed as to what they can or cannot construct. As a result, the current dispute resolution processes serve to increase the transparency of network service providers' processes rather than direct or regulate their decision making.

Designing the appropriate framework depends upon whether the dispute resolution should be as a "merits review" or a "compliance review". Under a merits review, the arbiter has the flexibility to take into consideration other relevant matters and is allowed to replace the DNSP's decision with a more suitable decision. For a compliance review, the arbiter assesses not whether the DNSP has made the right decision, but whether it has correctly complied with the NER. Further, in doing such a review, the arbiter may only have regard to the information that was available to the DNSP during the project assessment. As noted above, the Commission has recommended that disputes relating to the RIT-T be conducted as a compliance review.

[33] cl. 5.6.6(j) of the National Electricity Rules.

The Commission is seeking stakeholder comment on the appropriate effect of the dispute resolution process. In particular:

27. Should the dispute resolution process be restricted to reviewing the DNSP's compliance with the NER and requiring the DNSP to amend its analysis in its project assessments or annual planning report if it is found that it has not fully complied (i.e. compliance review)? Or, should the dispute resolution process provide for a review of the outcomes of the DNSP's project assessments or annual planning report and if it is found that the DNSP has not reached the best outcomes, direct the DNSP to implement the most suitable outcomes (i.e. merits review)?

# 6 Common Issues

This Chapter discusses some issues which are common to the various components of the national framework.

## 6.1 Establishing the National Framework in Rules and Guidelines

A matter for decision would be how to specify the national framework in the NER and how to determine the balance between what specification would be needed in the NER and what issues may be explained in supporting guidelines made by the regulator.

Prescription in the NER promotes certainty and stability of regulatory outcomes, but it may reduce the regulator's ability to accommodate the particular circumstances of individual market participants in regulatory decisions.

The current framework for the regulatory test has distinct but complementary aspects:

- principles on how the regulatory test should be applied, which are set out in the NER;
- the regulatory test developed by the AER in accordance with the principles set out in the NER; and
- guidelines for the operation and application of the regulatory test, which AER is required to published.

Under this framework, the NER set out principles that the AER must adopt in promulgating the test. The purpose of this is to ensure that the test is applied in a consistent manner, which provides a level of certainty to NSPs in undertaking new network investment, while leaving sufficient discretion with the AER to promulgate the test consistent with its role as the regulator.

The NERA/ACG Report proposed that with respect to the annual planning requirements the Rules should set out the key principles governing the process and that the AER should be required to provide a statement of specific requirements that is given effect by the Rules. The statement of specific requirements would set out a standard format and required contents of the annual planning report.[34]

This trade off between prescription in the NER and further explanation in supporting guidelines will need to be managed in implementing the national framework. The NER should address matters that have industry wide application or effects that are likely to change relatively infrequently over time and that do not rely on an assessment of individual market conditions or circumstances.[35]

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[34] NERA/ACG Report, p.24.

[35] Expert Panel on Energy Access Pricing, Final Report to MCE, June 2006 p. 25.

## 6.2 Exemption for urgent and unforeseen investments

In its recommendations for the RIT-T, the Commission proposed that "urgent and unforeseen" investment be exempt from the project assessment process. This recommendation was made to ensure that the new arrangements do not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place. Whether a similar exemption should be included in the distribution network planning framework will be considered in this Review. Any exemption would need to be drafted in a manner that prevents any opportunity for the business to exploit the exemption.

## 6.3 Relationship with other arrangements

When designing the national framework, it is important also to consider how the proposed arrangements will interact with the existing arrangements for DNSPs. There might be merit in making consequential changes to other arrangements to properly reflect the national framework.

There are two possible areas where such amendments might be appropriate. First, it may be beneficial to amend the NTP arrangements to require the NTP to take into consideration the most recent DNSP annual planning reports when developing the National Transmission Network Development Plan. Information in the DNSPs' annual planning reports may be useful to the NTP in preparing the development strategies for the national transmission grid.

Secondly, the list of factors (clauses 6.5.6(e) and 6.5.7(e)) tp which the AER must have regard in assessing the DNSP's proposed operational and capital expenditure could be amended to include the outcome of a project assessment process. The project assessment will identify useful information on the economic justification of a project that may assist the AER in its distribution determinations. The Commission proposed a similar amendment for transmission determinations as part of its RIT-T recommendations.

The Commission is seeking stakeholder comment on:

28. The appropriate balance of specification in the national framework between the Rules and supporting guidelines.

29. Should "urgent" investments be exempt from aspects of the national framework? If so, how should "urgent" be defined?

30. What consequential amendments should be made to other arrangements to reflect the implementation of the national framework?

# 7 List of Issues for Comment

| Issues | Questions for Comment |
|---|---|
| **Chapter 2: Proposed Scope and Approach** | |
| **The Commission's approach to the Review** | 1. The proposed scope for the Review;<br><br>2. The Commission's proposed approach and assessment criteria for the Review; and<br><br>3. The interaction between transmission and distribution network planning. |
| **Chapter 3: Annual Planning Requirements** | |
| **Scope of the annual planning and reporting process** | 4. In addition to emerging constraints, what other types of potential problems of the distribution network should be included in annual planning reports?<br><br>5. How could the interaction between transmission and distribution planning be reflected in annual planning and reporting process?<br><br>6. Should the annual planning report including reporting on work carried out by DNSPs including reporting of actual network performance information and historical data? |
| **Type and level of detail of information to be provided in annual planning reports** | 7. What factors need to be considered to ensure the level of detail of the information provided is useful and appropriate to stakeholders?<br><br>8. For the areas that are to be reported on, what specific factors should be considered? For example for emerging constraints, how should emerging constraints be classified and how could they be consistently set out?<br><br>9. Should a distinction be made between general information that is publicly available and more detailed information for embedded generators and demand side response proponents? |
| **Implementation of the** | 10. Would the Australian Energy Market Operator's |

| Issues | Questions for Comment |
|---|---|
| **annual planning and reporting process** | website be the appropriate central location for the planning reports to be stored and published?<br><br>11. What would be the appropriate timeframe for the publication of the DNSP annual planning report (noting the relationship between the timeframe for the publication of the TNSP annual planning report and the DNSP/TNSP joint planning requirements)? |
| **Chapter 4: Project Assessment and Consultation Process** | |
| **Thresholds to trigger project assessment under the RIT-D** | 12. What types of investments should be required to undertake the project assessment process?<br><br>13. What are the appropriate thresholds to trigger the project assessment process?<br><br>14. Should the thresholds should be indexed in accordance with CPI or subject to a periodic review? |
| **Identifying and consulting on options during project assessments** | 15. What factors should be considered in a RFP process and how should this be specified in the NER compared to AER guidelines? Including:<br><br>• what defines a credible option?<br><br>• what information is needed to enable market participants to raise alternatives?<br><br>• how long should the consultation take place?<br><br>• should an RFP process include elements to deal with the potential issue of DNSPs seeking assurance from non-network proponents for the performance of a non-network option? |
| **Identification & quantification of the costs and benefits of distribution projects** | 16. What is the appropriate list of costs and benefits associated with distribution projects, and should that list be mandated in the NER?<br><br>17. How should the range of benefits to be quantified under the project assessment process be determined? |

| Issues | Questions for Comment |
|---|---|
| | 18. How can the project assessment process ensure that environmental benefits are appropriately treated and quantified? |
| **Decision making criteria to determine most economic option** | 19. How should a net benefit test be designed for distribution investments assessments?<br><br>20. Is there a need for a more specific decision making criterion compared to the existing regulatory test? |
| **Chapter 5: Dispute Resolution Process** | |
| **Scope of issues subject to dispute resolution** | 21. Should the dispute resolution process only apply to project assessments undertaken by DNSPs under the regulatory test or should the dispute resolution process also apply to matters arising from DNSPs' annual planning processes?<br><br>22. What is the appropriate scale of distribution projects that should be subject to the dispute resolution process? Should the threshold for the dispute resolution process be aligned with the threshold for the project assessment process? |
| **Operation of the dispute resolution process** | 23. Who should be able to initiate the dispute resolution process?<br><br>24. What process should be followed to resolve disputes and what should be the timing for this process? Should parties be required to undertake formal mediation process before the dispute is referred for a binding determination? What aspects of the proposed process for transmission should apply to distribution?<br><br>25. Who should make binding determinations to resolve disputes? Is the AER the most appropriate body? If a mediation process is used, who should be the mediator for disputes?<br><br>26. Should the appointed arbiter have the ability to reject disputes immediately if the grounds for the dispute are invalid, misconceived or lacking in substance? |

| Issues | Questions for Comment |
| --- | --- |
| **Outcome of the dispute resolution process** | 27. Should the dispute resolution process be restricted to reviewing the DNSP's compliance with the NER and requiring the DNSP to amend its analysis in its project assessments or annual planning report if it is found that it has not fully complied (i.e. compliance review)? Or, should the dispute resolution process provide for a review of the outcomes of the DNSP's project assessments or annual planning report and if it is found that the DNSP has not reached the best outcomes, direct the DNSP to implement the most suitable outcomes (i.e. merits review)? |
| **Chapter 6: Common Issues** | |
| **Relationship of the national framework with other arrangements** | 28. The appropriate balance of specification on the national framework between the NER and supporting guidelines.<br><br>29. Should "urgent" investments be exempt from aspects of the national framework? If so, how should "urgent" be defined?<br><br>30. What consequential amendments should be made to other arrangements to reflect the implementation of the national framework? |

# A Terms of Reference

**AEMC Review of National Framework for Electricity Distribution Network Planning and Expansion**

As outlined in the 2006 amended Australian Energy Market Agreement (AEMA), there are a number of energy distribution and retail regulatory functions currently carried by jurisdictions which are being transferred to the national framework. A number of functions have already been transferred to the national framework as part of the recent economic package. There are some outstanding items currently being addressed by the Ministerial Council on Energy (MCE), which will be implemented via the retail non-economic legislative package. One of the outstanding items to be addressed is the national framework for determining when distribution network extensions are part of a regulated service. This influences the electricity distribution economic network planning framework.

In 2007, the MCE Standing Committee of Officials (SCO) commissioned a report by NERA Economic Consulting (NERA) and the Allen Consulting Group (ACG) to provide advice on a national framework for electricity distribution network planning, connections and capital contribution arrangements. Following the release of the NERA/ACG report titled *Network Planning and Connection Arrangements - National Frameworks for Distribution Networks* in August 2007, there was a period of consultation and receipt of written submissions.

In the process of developing a policy response to the NERA/ACG report's recommendations it has become apparent that, given recent developments in the National Electricity Market (NEM), including the development of a Regulatory Investment Test for Transmission, the proposed introduction of a Carbon Pollution Reduction Scheme and increased Renewable Energy Target and the AEMC review of Demand Side Participation in the NEM, further analysis and consultation is required before the details of the arrangements governing planning and expansion of electricity distribution networks can be finalised.

In this regard, the MCE has agreed to direct the AEMC to conduct a review of the electricity distribution planning and expansion framework and undertake the necessary stakeholder consultation, with the objective of creating a national framework that conforms to the high level policy parameters outlined below.

**MCE direction to the AEMC**

Section 41 of the National Electricity Law (NEL) enables the MCE to direct the AEMC to review any matter relating to the NEM or any other market for electricity.

Pursuant to section 41 of the NEL, the MCE directs the AEMC to conduct a review into the current distribution network planning and expansion arrangements which exist across the NEM jurisdictions, and propose recommendations to assist the establishment of a national framework for distribution networks, having regard to the National Electricity Objective in the NEL.

The AEMC review shall provide detailed advice on implementation of any recommendations the AEMC considers appropriate to implement a national framework for electricity distribution network planning, which may include changes to the National Electricity Rules (the Rules). The review will not cover distribution network connections or other network access issues as these are to be addressed by the MCE via a separate process.

***Purpose of distribution network planning and expansion framework***

The specific outcomes intended to be achieved by the National Framework for Electricity Distribution Network Planning include:

- Ensure Distribution Network Service Providers (DNSPs) have a clearly defined and efficient planning process which provides certainty in relation to approval of network expansion and augmentation to maintain the reliability of the electricity supply to consumers.

- Ensure DNSPs develop the network efficiently. This includes addressing a perceived failure by DNSPs to look at non-network alternatives (such as embedded generation, energy efficiency and conservation measures) in a neutral manner when making distribution augmentation assessments.

- Appropriate information transparency to allow:

  – network users, including distributed generators, to plan where best to connect to the network and provide an appropriate regulatory environment to facilitate this;

  – network users to understand how the timing of connection might affect connection charge arrangements, to the extent which connecting users contribute to upstream augmentation requirements; and

  – efficient planning by parties that may offer alternative, more cost-effective solutions to network augmentations to address emerging constraints.

The principal means for achieving these objectives is to require DNSPs to undertake standard and comprehensive forward planning, and where appropriately triggered, conduct a robust economic assessment of alternatives. Information transparency regarding analysis and decisions made, and recourse to dispute decisions where appropriate, are also viewed as being paramount to ensure compliance and accountability.

The above mentioned drivers for electricity distribution network development and planning arrangements are also important within the context of the creation of a consistent national framework, which will look to:

- Ensure a level playing field for all regions in terms of attracting investment and promoting more efficient decisions, in that the same overarching regulatory framework applies across the NEM; and

- Reduce the regulatory compliance burden for participants operating in more than one region in the NEM.

*Key elements of the national distribution network planning and expansion framework*

The MCE agrees that the national electricity distribution network planning framework should comprise the following key elements:

- The electricity distribution network framework should contain an annual planning process in which DNSPs produce a 5 year forward planning report;

- The report will be published annually and be publicly available;

- At a minimum the annual plan will forecast distribution network constraints. Current jurisdictional distribution planning requirements require planning for load growth generally, or transmission interface specifically, as a basic minimum. Other possible factors for inclusion in the annual plan could include, but be not limited to: adequacy of transmission interchange capacity, general network capacity and summer and winter peak capacity;

- There will be a requirement for DNSPs to undertake case by case project assessments triggered by certain thresholds; and

- There will be a dispute resolution process.

In the context of the specified key framework elements and purpose, the AEMC review should consider:

- The range and level of detail of information required to be included in the annual planning report, balancing the cost of producing the report with the benefit that will potentially be realised by the users of the report;

- The thresholds applied in various levels of the case by case assessments;

- The dispute resolution aspect of the distribution network planning framework;

- The distribution network regulatory test and its application;

- Overlaps with other relevant planning and reporting documents required by jurisdictional regulators or the Australian Energy Regulator;

- The views of non-network proponents on the usefulness and appropriateness of the information for identifying non-network solutions; and

- The cost to DNSPs in producing these reports.

In developing its recommendations and proposed new Rules or Rules changes to implement the national framework for distribution networks, the AEMC should seek to achieve consistency, to the extent appropriate, with the electricity transmission planning framework.

In conducting this review, the AEMC is to consider other relevant current and past reviews and Rules changes. These include:

- The NERA/ACG report Network Planning and Connection Arrangements – National Frameworks for Distribution Networks;
- Jurisdictional regulatory codes and guidelines;
- The Implementation Plan for the National Transmission Planner; and
- The Demand Side Participation Review.

**Timing and process**

The MCE requires the AEMC to:

- Undertake a formal consultation process including publication of a scoping paper and draft report;
- If considered appropriate by the AEMC, they may also hold a public forum; and
- Provide its final report by 30 September 2009.

# B Summary of Current Distributor Planning Requirements

**Summary of the Current Distributor Planning Requirements**[36]

| | NER | QLD | NSW | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| **Regulatory Instruments** | NER Chapter 5 – clauses 5.6.2 and 5.6.5A | The Electricity Act 1994 requires that a DNSP is to be licensed and to comply with approved codes.<br><br>The Electricity Regulation 2006 approves the Queensland Electricity Industry Code as the approved code under the Act.<br><br>The Queensland Electricity Industry Code sets out the provisions for a planning report. | The Electricity Supply Act 1995 requires the licence conditions that require DNSPs to conduct and publish analysis on the cost effectiveness of any demand management strategies and to report annually on the results.<br><br>The Electricity Supply (safety and management) Regulation 2008 requires DNSPs to produce and lodge a network management plan with the Director-General when requested to do so.<br><br>The New South Wales demand management code of practice provides guidance for DNSPs on how to meet the requirements of the licence conditions for meeting the demand management and planning provisions. Breach of the code could be considered a breach of the licence conditions. | The Electricity Distribution Licence provisions require that DNSPs comply with the Electricity Distribution Code.<br><br>The Electricity Distribution Code 2006 requires DNSPs to publish an annual planning report. | The Electricity Act 1996 requires that DNSPs be licensed and that DNSPs are to investigate and publish the results of demand management strategies.<br><br>The licence provisions give effect to the requirements that the DNSP in South Australia – ETSA – investigate demand management solutions.<br><br>Essential Services Commission of South Australia (ESCOSA) has published Electricity Industry Guideline Number 12 (Guideline 12) to set out provisions for how ETSA is to meet its obligations on reporting and consulting on any system constraints identified and demand management plans. | The Electricity Supply Industry Act 1995 sets out the requirement for the DNSP to be licensed. The Act further requires that the DNSP comply with the Tasmanian Electricity Code.<br><br>The Tasmanian Electricity Code sets out the requirement for the DNSP to provide an annual report to the regulator. |

[36] There are no additional state-based requirements for the ACT.

**Summary of the Current Distributor Planning Requirements**[36]

| | NER | QLD | NSW | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| **Planning requirements** | *Plan covering the next 5 years.*<br><br>DNSPs to analyse expected future operation over a 5 year period. (5.6.2(a))<br><br>Joint planning requirements with TNSPs where DNSPs and TNSPs are to jointly conduct an annual planning review including consideration of DNSPs' forecast loads and review of adequacy of existing connection points and future connection points. (5.6.2(b)) | *Plan covering the next 5 years.*<br><br>DNSPs to produce a Network Management Plan (NMP) under the code to set out how the DNSP is to manage and develop its supply network.<br><br>Additional plans – The regulator may request DNSPs to prepare a "summer preparedness plan". | *Network management plan unspecified period. Demand management plan covering the next 5 years.*<br><br>Under the regulation, DNSPs are to review the network management plan when any significant changes occur and in any event at least once every 2 years.<br><br>Additional plans – Under the code of practice, DNSPs are to include an "Electricity System Development Review" (ESDR), looking out over the "foreseeable future", in the network management plan. | *Plan covering the next 5 years.*<br><br>Under the code, DNSPs are required to produce plans on meeting forecasted demand requirements and improving reliability looking at the next five years in a Distribution System Planning Report (DSPR). | *Plan covering the next 3 to 5 years.*<br><br>ETSA is required to publish an Electricity System Development Plan (ESDP) setting out its planning criteria and five years of historical and forecast load data and expected network constraints over the next three years. | *Plan covering the next 5 years.*<br><br>Under the code, the DNSP is required to provide an annual plan on meeting predicted demand and improving reliability covering the next five years. |
| **Contents of plans** | *Requirements are outlined in clause 5.6.2.*<br><br>Clause 5.6.2 sets out the factors to be considered by DNSPs in its planning including analysis of:<br><br>• Expected future operation;<br><br>• Forecast loads; future generation; market network service; demand side; and transmission developments to be taken into account;<br><br>• existing connection | *Requirements are outlined in the code.*<br><br>The Electricity Industry Code section 2.3.2 specifies that the network management plan is to include:<br><br>• Background providing an explanation of the purpose of the report;<br><br>• General information on the DNSP's supply network;<br><br>• Forecasts and discussion of the current operating environment; | *Requirements are outlined in the regulation for the "management" plan and a specific guideline is issued by the Department of Energy, Utilities and Sustainability (DEUS) for the "performance" plan.*<br><br>The Electricity Supply (Safety and Network Management) Regulation 2008, Part 3, sets out the required contents for the network management plan. These include discussion of:<br><br>• Characters of the | *Requirements are outlined in the code.*<br><br>The Electricity Distribution Code section 3.5 specifies that the distribution system planning report is to detail plans for the following 5 years covering areas including:<br><br>• Forecast and historical demand;<br><br>• Feasible options for meeting forecast demand including opportunities for embedded generation | *Requirements are outlined in an industry guideline.*<br><br>The Electricity Industry Guideline No. 12 (made under section 8 of the Essential Services Commission Act 2002) sets out in detail the DNSP's obligations to report and consult on its system constraints and demand management plans. The guideline specifies that the ESDP is to include:<br><br>• Background providing an explanation of the | Requirements are outlined in the code.<br><br>The Tasmanian Electricity Code clause 8.3.2 specifies that an annual distribution system planning report detailing plans over the following five years is to include:<br><br>• Forecast and historical demand;<br><br>• Feasible options for meeting forecast demand including opportunities for embedded generation |

**Summary of the Current Distributor Planning Requirements**[36]

| | NER | QLD | NSW | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| | points and future connection points; and<br>• Potential system limitations. | • Asset management policy and qualitative assessment of its compliance with the policy;<br>• Demand management strategy including description of existing and planned programs and opportunities for demand side participation;<br>• Historical reliability performance for the previous five year period;<br>• Statement of reliability targets for the next five years including details of improvement programs including major expenditure initiatives; and<br>• Risk assessment of major constraints. | distribution network;<br>• Planning process employed including demand management technologies; system reliability planning standards;<br>• Asset management strategies including risk management; technical service standards for quality and reliability of supply;<br>• Safety management strategy including analysis of hazardous events; emergency procedures; adherence to safe working procedures;<br>• Strategies employed to comply with licence conditions relating to the design and operation of the system.<br>The DEUS guideline sets out in detail the requirements of the annual network performance plan. The plan sets out the requirement to provide operational and planning statistics including in relation to:<br>• Audits and independent | and demand management;<br>• Preferred option for meeting forecast demand details including estimated costs;<br>• Ability to defer or avoid augmentation by reducing forecast demand through embedded generation or demand management;<br>• Impact of loss load assessment;<br>• Planning standards employed;<br>• Reliability improvement programs description including the nature, timing, cost and expected impact on performance;<br>• Reliability programs evaluation. | purpose of the report;<br>• General information on the DNSP's supply network;<br>• Descriptions of the basis for formulating load forecasts;<br>• System planning and reliability guidelines;<br>• Description of the state-wide sub-transmission network;<br>• Regional development plans;<br>• Consultation framework;<br>• Register of interested parties. | and demand management;<br>• Preferred option for meeting forecast demand details including estimated costs;<br>• Ability to defer or avoid augmentation by reducing forecast demand through embedded generation or demand management;<br>• Assessment of load at risk for the system and supply regions;<br>• Planning standards employed;<br>• Reliability improvement programs description including the nature, timing, cost and expected impact on performance;<br>• Reliability programs evaluation. |

**Summary of the Current Distributor Planning Requirements**[36]

| | NER | QLD | NSW | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| | | | appraisals conducted;<br>• Network design planning criteria;<br>• Technical service standards;<br>• Detailed annual performance results;<br>• Network safety incidents and incident reports;<br>• Customer installations. | | | |
| **Reporting requirements** | *No requirement to publish planning reports.*<br><br>DNSPs have no requirement to publish any periodic planning reports however, TNSPs are required to publish planning reports annually including outcomes of the joint planning with DNSPs. (5.6.2A)<br><br>If a DNSP identifies a potential constraint, it must notify and publish a report to registered participants, NEMMCO and interested parties of the constraint and advise the corrective action that would be taken. (5.6.2(e)) | *Reports to be publicly available.*<br><br>DNSPs are to produce NMP reports on an annual basis. | *Reports to be provided to Government.*<br><br>The Network Performance Plan (including the ESDR) is to be lodged annually with the Government. DNSPs publish plans publicly. | *Reports to be publicly available.*<br><br>DSPRs are to be published annually. These reports are available publicly and are required to be published on the DNSPs' websites. | *Reports to be publicly available.*<br><br>The ESDP is to be published annually and make the plan available on its website. | *Reports to be provided to the regulator and participants.*<br><br>The annual plan is to be provided to the regulator and made available to licensed participants and interested parties. |

**Summary of the Current Distributor Planning Requirements**[36]

| | NER | QLD | NSW | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| **Consideration of non-network alternatives** | *No clear requirement that distributors must consider non-network alternatives.* | *General provisions.*<br><br>As a part of the NMP, DNSPs are to include a demand management strategy. | *Projects over $200,000.*<br><br>The code of practice requires that DNSPs issue formal requests for proposals requesting non-network solutions for projects with an annualised cost over $200,000. | *General provisions.*<br><br>The code sets out requirements to include consideration of any feasible options to meet demand forecasts including embedded generation and demand management. | *Projects over $2m.*<br><br>Under Guideline 12, projects that meet a “reasonable test”, where the estimated capital costs is at least $2m, ETSA is required to consider non-network solutions. | *General provisions.*<br><br>The code sets out requirements to include consideration of any feasible options to meet demand forecasts including embedded generation and demand management. |
| **Pre-assessment & consultation on options** | *Consultation for projects over $10m.*<br><br>For proposed new assets over $10m DNSPs are required to consult with affected registered participants, NEMMCO and interested parties on possible options (including but not limited to demand side options, generation options and market network services). (5.6.2(f)) | *No specific provisions for consultation.* | *Consultation with interested parties on all constraints identified. Consultation on non-network projects over $200,000.*<br><br>DNSPs are to consult with interested parties on any constraints identified to occur within five years.<br><br>Sections S4 and S5 of the code of practice provides detailed guidance on requirements for a request for proposal (RFP) as well as the proposal itself.<br><br>The RFP is to include details on the level/timing of system support required and relevant and up-to-date information on the system loads and forecasts.<br><br>The proposal should include details on the proposed demand | *No specific requirements for consultation.* | *Consultation for projects over $2m.*<br><br>For projects that meet the reasonable test, ETSA must seek options of possible non-network solutions through issuing requests for proposals.<br><br>Guideline 12 sets out reasonable test and the request for proposals process. The requests for proposals are to have details of the required demand management characteristics including the financial incentive available for a permanent and temporary reduction in demand ($ per KVA) | *No specific requirements for consultation.* |

**Summary of the Current Distributor Planning Requirements**[36]

| | NER | QLD | NSW | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| | | | management or generation solution and related payments that would be required. | | | |
| **Evaluation of options** | *Evaluation of projects that past the regulatory test.*<br><br>Publish economic assessment for projects over $10m. (5.6.2(h))<br><br>A DNSP would carry out cost effectiveness analysis that satisfies the regulatory test for each option identified.[37] Publish the results of the cost effective analysis for the DNSP preferred proposal. (5.6.2(g) and (h)) | *No economic tests are required for projects less than $10m.*<br><br>For projects over $10m, the provisions under the NER apply. | *All options to be assessed and ranked in order of annualised costs.*<br><br>The code of practice requires that the evaluation of all options be based on ranking the total annualised costs for providing system support.<br><br>Evaluation period is 10 years although alternate timeframes may be considered. | *No specific requirements.*<br><br>DNSPs are to include their planning standards and descriptions of options considered, including estimated costs for the "preferred option". | *Evaluation of projects in accordance with regulatory test and rank in accordance of annualised costs.*<br><br>Evaluation is to be completed for all options and be consistent with the regulatory test under the Rules. Options are all to be ranked in accordance with annualised costs.<br><br>ETSA is to make all proposals publicly available. | *No specific requirements.*<br><br>DNSPs are to include their planning standards and descriptions of options considered, including estimated costs for the "preferred option". |
| **Dispute resolution** | Dispute resolution process under the NER available to registered participants in relation to new large assets.<br><br>Registered participants may dispute the DNSPs recommendations only for projects over $10m of a project that is likely to result in service charges | No formal mechanism for dispute resolution if a party disagreed with the assessment of the DNSP. | No formal mechanism for dispute resolution if a party disagreed with the assessment of the DNSP. | No formal mechanism for dispute resolution if a party disagreed with the assessment of the DNSP. | No formal mechanism for dispute resolution if a party disagreed with the assessment of the DNSP. | No formal mechanism for dispute resolution if a party disagreed with the assessment of the DNSP. |

[37] Rule 5.6.5A provides that the AER is to develop and publish the regulatory test, the purpose of which is to identify new network investments or non-network alternative options that maximise the net economic benefit to all those who produce, consume and transport electricity in the market. In the event the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 of the Rules or in applicable regulatory instruments, minimise the present value of the costs of meeting those requirements.

**Summary of the Current Distributor Planning Requirements**[36]

| | NER | QLD | NSW | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| | of more than 2%. The registered participant and the DNSP are to "negotiate in good faith". (5.6.2(i)) (in which case the dispute resolution process under Chapter 8 would apply). | | | | | |
| **Other provisions** | Provisions for the establishment of the regulatory test sets out that the required analysis should not be disproportionate to the scale and size of the new network investment (5.6.5A(c)(6)) | | | | Under Guideline 12, ESCOSA believes the $2m threshold for considering non-network solutions would cover the projects where non-network solutions would be feasible whilst not imposing an undue cost on ETSA. | |