Final Decision

Regulatory Test version 3 & Application Guidelines

November 2007

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Glossary

AER	Australian Energy Regulator
AEMC	Australian Energy Market Commission
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
CPI	Consumer Price Index
COAG	Council of Australian Governments
DNSP	Distribution Network Service Provider
ERIG	Energy Reform Implementation Group
ESCOSA	Essential Services Commission of South Australia
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
LRMC	Long Run Marginal Cost
MCE	Ministerial Council on Energy
MITC	Market Impact of Transmission Congestion
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
RFI	Request for information
RFP	Request for proposals
SRMC	Short Run Marginal Cost
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

Summary

Under clause 5.6.5A of the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for developing and publishing the regulatory test.

The regulatory test is an analysis tool used by transmission and distribution businesses in the National Electricity Market (NEM) to assess the efficiency of network investment. The public consultation process for new large network assets provides information to the market on the development of the network and allows stakeholders to comment on proposed investments. The AER considers that maintaining the regulatory test in its current form, with some amendments to ensure consistency with the amended NER, simplify the test and improve its clarity, is appropriate.

Following the making of the *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006* in November 2006, the AER must publish a regulatory test which complies with the requirements set out in clause 5.6.5A of the NER. The AER must also publish application guidelines to assist in the application of the test. The current regulatory test has been deemed to be consistent with the NER until the end of 2007.

Clause 5.6.5A(f) of the NER requires the AER to publish a new regulatory test and application guidelines before the end of 2007. A proposed regulatory test version 3 was published for public consultation on 26 July 2007.

The AER's proposed revisions to the regulatory test reflected two key requirements the NER places on the market benefits limb of the test:

- a procedural requirement to gather information on alternative options and
- the introduction of the notion of 'likelihood' in the consideration of alternative options.

The AER also published proposed regulatory test application guidelines for consultation. Submissions on the proposed regulatory test version 3 and application guidelines closed 6 September 2007.

The AER has considered submissions received on the proposed regulatory test version 3 and application guidelines. The AER's responses to submissions are set out in this final decision. The AER notes that the main changes that have been made to the test since the proposed version are in relation to:

- implementing a less prescriptive request for information process and
- including 'commercially feasible' as a factor for consideration for the likelihood of an alternative option.

The AER has followed the consultation procedures set out in clause 6A.20 of the NER in publishing the regulatory test version 3 and application guidelines and issues version 3 of the regulatory test and final application guidelines at the same time.

1 Introduction

The AER regulates the revenues of transmission network service providers (TNSPs) in the NEM in accordance with the NER. Under clause 5.6.5A of the NER, the AER is also responsible for developing and publishing the regulatory test.

This final decision accompanies the *regulatory test version 3* and *regulatory test application guidelines*. This final decision responds to submissions and provides reasons for the AER's final decision on the regulatory test version 3 and application guidelines, satisfying the requirements set out in clause 6A.20 of the NER.

Where a submission has been made on a particular amendment this decision sets out

- a summary of the submission
- the AER's final decision on the proposed amendment including its response to submissions and any considerations.

1.1 NER requirements

Under clause 5.6.5A of the NER, the AER is responsible for developing and publishing the regulatory test. The regulatory test is a tool used by transmission and distribution businesses in the NEM to assess the efficiency of network investment. Version 2 of the regulatory test the test is comprised of two limbs:

1. *The reliability limb*- this is applied to reliability driven augmentations which are based on service obligations imposed by the NER or state legislation, regulations or statutory instruments. A reliability augmentation will satisfy the test if it is the least cost option considering the total costs of alternative options to those who produce, distribute or consume electricity in the NEM.
2. *The market benefits limb*- this is applied to any investment not assessed under the reliability limb. New investment will satisfy the market benefits test if it maximises the net present value of the net market benefits having regard to alternative options, timing and market development.

Following a Rule change in November 2006, the NER requires the AER to publish:

- a regulatory test which complies with the principles set out in clause 5.6.5A and
- application guidelines to assist network service providers (NSPs) in applying the test.

Transitional provisions in the NER provide that the current regulatory test is deemed to comply with the NER until 31 December 2007, however a regulatory test which is consistent with clause 5.6.5A must be published by the end of this year.

The AER followed the consultation procedures set out in clause 6A.20 of the NER in publishing the regulatory test version 3 and application guidelines in a commitment to open and transparent regulation.

Comments were sought from interested parties on the proposed regulatory test version 3 and the proposed application guidelines. In particular, the AER sought views on the proposed request for information (RFI) process included in the proposed regulatory test and the application guidelines.

The AER received submissions from:

- Energex
- Energy Australia
- Energy Response
- the Energy Transmission Network Owners Forum (ETNOF)
- Ergon Energy and
- the Major Energy Users (MEU).

The AER's response to these submissions is set out below.

1.2 Policy context

The AER notes that this review of the regulatory test is taking place in a broader policy environment where the role and function of the regulatory test may potentially change.

Relevant policy work impacting on the regulatory test includes:

- the Australian Energy Market Commission's (AEMC) current task of integrating the two limbs of the test as part of the implementation of new transmission planning arrangements and
- the Ministerial Council on Energy's (MCE) development of rules for the economic regulation of distribution.

While these policy developments may deliver significant changes to the regulatory test, the AER notes that it still has a requirement under the NER to review the regulatory test and publish regulatory test application guidelines by the end of this year.

In relation to the AER's clarification amendments, EnergyAustralia has submitted that the AER should limit its regulatory test revisions to those that will achieve consistency between the test and the NER. EnergyAustralia considers that some of the clarifications to the test may be costly to implement and short-lived given the AEMC's work to integrate the limbs.

While the AER acknowledges this concern, it considers that it is important to provide a clearly articulated and precise regulatory test for market participants and network planners. While the AEMC's work to integrate the two limbs may well supersede the regulatory test in its current form, the AER notes that at this time the distinction between the reliability limb and the market benefits limb must be retained.

The AEMC has commenced its review and is to advise the MCE on the implementation of new transmission planning arrangements by June 2008 with the new arrangements to commence by June 2009. The AER is mindful of publishing a clear and sound regulatory test which the AEMC may draw from to implement enhanced national planning arrangements.

1.2.1 The application of the regulatory test to distribution assets

Clause 5.6.2(g) of the NER requires distribution network service providers (DNSPs) to carry out an economic cost-effectiveness analysis of possible options to identify options that satisfy the regulatory test.

Ergon Energy and Energex have submitted that the AER's regulatory test should not apply to distribution network investment. Energex submits that:

> .. The formal application of the regulatory test for DNSPs is an onerous requirement given the shorter planning horizon, lack of economically viable alternative options and volume of projects undertaken. Energex would prefer that the requirements for DNSPs to undertake the regulatory test are removed from the Guidelines and a workable set of rules for DNSPs be developed.

Both Ergon Energy and Energex acknowledge that this issue is outside the ambit of the AER's current revisions to the test and is to be addressed in the MCE's development of distribution rules. The AER reiterates that the requirement for DNSPs to satisfy the regulatory test lies within the NER rather than the test itself or the application guidelines, putting this issue beyond the scope of this review.

1.3 Incremental approach

Due to the policy developments surrounding the regulatory test the AER is adopting an incremental approach in this review.

The AER's revisions to the test are therefore limited to:

- those necessary to achieve consistency between the regulatory test and the NER (consistency amendments) and
- those which simplify or improve the clarity of the test based on recent experience (clarification amendments).

1.4 Structure of this paper

This paper is structured as follows:

- Section 2 sets out the AER's final decision on revisions to the test to achieve consistency with the NER
- Section 3 sets out the AER's final decision on amendments to the test to simplify it and improve its clarity
- Section 4 sets out the AER's final decision on the application guidelines

- Appendix A sets out the regulatory test version 3 and
- Appendix B sets out the comparison between version 2 and version 3.

2 Consistency with the NER

2.1 Introduction

The *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006* introduced a number of requirements on the regulatory test, predominantly on the market benefits limb of the test. The AER is making amendments to the test to satisfy these requirements and achieve consistency between the test and the amended NER.

The AER considers the regulatory test already satisfies a number of the principles contained in the NER. However, where the regulatory test is silent or unclear in relation to certain principles, the AER makes a number of amendments to achieve consistency with specific parts of clause 5.6.5A.

This chapter sets out the AER's final decision in relation to its proposed amendments to make the regulatory test consistent with the NER. Where a submission has been made on a particular amendment this determination sets out:

- a summary of the submission and
- the AER's final decision on the proposed amendment including its response to submissions and any considerations.

The AER has retained proposed revisions which were minor or uncontroversial.

2.2 Revised introduction

2.2.1 Proposed amendment

The AER proposed a revision to the introduction to the regulatory test to provide context and broad objectives. The introduction reflects the NER definition of new large network assets as being expected capitalised expenditure greater than $10 million.

2.2.2 Submissions

The Electricity Transmission Network Owners Forum (ETNOF) submits that the introduction should not include the $10 million threshold as it may be changed in the NER and thus cause confusion as the regulatory test will need to be changed to match.

2.2.3 AER final decision

The AER acknowledges ETNOF's concern but considers this threshold to be basic and essential information to users of the test. The AER has therefore retained the statement but clarified that where this value differs from the value stated in chapter 10 of the NER, the NER value applies.

The AER clarifies that where a proposed investment is a mix of replacement and augmentation, a regulatory test should be conducted on the augmentation component if that augmentation component lies over the $1 million threshold.

2.3 The reliability and market benefits limb

2.3.1 Proposed amendment

Clause 5.6.5A(b) of the NER states that the purpose of the regulatory test is to identify new network investments or non-network alternative options that:

> (i) maximise the net economic benefit to all those who produce, consume and transport electricity in the market; or
>
> (ii) in the event the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in *applicable regulatory instruments*, minimise the present value of the costs of meeting those requirements.

The AER considers that the wording of this purpose should be reflected in the regulatory test to align it with the NER. As such, the AER has amended the test to state:

> An option satisfies the regulatory test if:
>
> (a) in the event the option is necessitated principally to meet the service standards linked to the technical requirements of schedule 5.1 of the Rules or in *applicable regulatory instruments* - the option minimises the present value of the *costs* of meeting those requirements, compared with *alternative option/s* in a majority of *reasonable scenarios*;
>
> (b) in all other cases - the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the present value of the *market benefit* less the present value of *costs*.

The AER has removed the word ‘timings’ from paragraph 1(b) of the current version of the regulatory test for the purposes of simplifying the test. The concept of timings is already incorporated into the sensitivity testing for reasonable scenarios and is not essential to the meaning of paragraph 1(b).

2.3.2 Submissions

No submissions were received in relation to this amendment.

2.3.3 AER final decision

As proposed.

2.4 Definition of reliability augmentation

2.4.1 Proposed amendment

In the *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006* the AEMC amended the definition of reliability augmentation in chapter 10 of the NER to substitute the word ‘solely’ with the word ‘principally’.

The NER definition now reads:

> A reliability augmentation is a *transmission network augmentation* that is necessitated **principally** by inability to meet the minimum *network* performance requirements set out in schedule 5.1 or in relevant legislation, regulations or any statutory instrument of a *participating jurisdiction*.

The term reliability augmentation is used in various parts of the NER in relation to establishing new large transmission assets, inter-regional planning, requirements surrounding Annual Planning Reports (APR) and information to be provided in a revenue proposal. Paragraph 1(a) of the regulatory test known as the ‘reliability limb’ relates to reliability driven augmentations. Whilst the term ‘reliability augmentation’ is not explicitly used in clause 5.6.5A of the NER or the regulatory test, the reliability limb needs to reflect the language used in the NER for consistency and clarity.

The AER has made a corresponding amendment to the reliability limb of the regulatory test to reflect the substitution of the word ‘solely’ with ‘principally’ and ensure consistency between the NER and the test.

2.4.2 Submissions

No submissions were received in relation to this amendment.

2.4.3 AER final decision

As proposed.

2.5 Broad objectives

2.5.1 Proposed amendment

Clause 5.6.5A(c) of the NER features two broad objectives for the market benefits limb of the regulatory test, namely that it:

> (6) not require the level of analysis to be disproportionate to the scale and size of the *new network investment*;
>
> (7) be capable of predictable, transparent and consistent application

The current regulatory test recognises that sensitivity testing should be appropriate to the size and type of project being assessed. However clause 5.6.5A(c)(6) now requires this concept of proportionality to be broadened to encompass the whole market benefits analysis. The AER does not consider that the current test requires a level of analysis which is disproportionate to the scale of the option being assessed. However, to make it explicit and to achieve a degree of consistency with the NER, the AER has included this concept in the introduction of version 3 of the regulatory test.

In relation to clause 5.6.5A(c)(7), the AER is cognisant of this requirement in developing the test, and will endeavour to ensure the market benefits test is as clear and capable of predictable, transparent and consistent application as possible. The application guidelines and some of the amendments made in this decision are an effort to improve the clarity and simplicity of the test to further meet this requirement in the NER.

In addition, the AER considers that requiring NSPs to include detailed calculations of how costs and benefits in regulatory test analyses and to make these available to interested parties enhances the transparency of the test and its ability to be consistently applied. The AER therefore includes a new provision in the test effecting this.

In relation to the requirement that the market benefits limb include an “assessment of reasonable scenarios of future supply and demand conditions” the AER considers that this is already required by the current test. The current test requires a market benefit analysis to be based on a comparison of options in a number of reasonable scenarios which includes reasonable forecasts of:

- electricity demand
- the operating costs of supplying energy (current supply) and
- committed, anticipated and modelled projects (ie: future supply).

As such the AER does not propose any amendments in relation to this provision.

2.5.2 Submissions

No submissions were received in relation to this issue.

2.5.3 AER final decision

As proposed.

2.6 Counterfactual analysis

2.6.1 Proposed amendment

Under the NER the market benefits limb of the regulatory test must be based on a cost-benefit analysis of the future with the new investment compared to the “likely alternative options” in the event that the NSP’s proposal does not take place. Clause 5.6.5A of the NER states that:

> (c) In so far as it relates to paragraph (b)(1), the *regulatory test* must:

(1) be based on a cost-benefit analysis of the future (which includes assessment of reasonable scenarios of future supply and demand conditions):

(i) were the *new network investment* to take place, compared to the likely alternative option or options,

(ii) were the *new network investment* not to take place.

The AER considers that the current market benefits limb of the regulatory test requires an assessment of the future should the proposed network option take place against an alternative option were the network option not to take place. The test already effectively compares what would happen in the market should one option take place against what would happen if another option took place. It is merely expressed differently.

2.6.2 Submissions

ETNOF agrees with the AER that the current wording of the regulatory test supports a counterfactual approach adopted by the NER. ETNOF states:

> ETNOF supports the AER's view that the current wording of the the regulatory test already allows for the net economic benefit of one option to be compared with the net economic benefit of not undertaking that option… ETNOF agrees with the AER that no drafting changes are needed to give effect to the counterfactual approach in the amended NER.

2.6.3 AER final decision

As proposed, the AER has decided not to make any changes to the regulatory test to reflect a counterfactual approach, as the approach is already accommodated in the current wording.

2.7 Alternative options

2.7.1 Proposed amendment

Clause 5.6.5A(c)(8) of the NER states that the regulatory test must provide that alternative options considered as part of a market benefits assessment may include (without limitation) generation, demand side management, other network options, or the substitution of demand for electricity by the provision of alternative forms of energy.

The AER therefore proposed to amend the test to give effect to this requirement, as well as to allow combinations of different types of options to be considered as an alternative option. For example, a combination of a demand-side option and a generation option could together constitute a viable alternative option to a proposed network augmentation.

Given the elimination process around 'likelihood' the AER has removed the requirement that alternative options be commercially feasible. The AER considers that leaving this requirement in the test would place too high a hurdle on proposed options to qualify as alternative options, and would effectively eliminate them from the decision making process before the judgement as to their likelihood may take place. Further, it is unnecessary for options to be disqualified from consideration at that stage of decision making given that the test now provides for an alternative option to be assessed on its likelihood separately.

The AER therefore proposed to amend the idea of ‘practicability’ in the regulatory test to not include ‘commercially feasible’ and simply mean technically feasible.

2.7.2 Submissions

No submissions were received in relation to this amendment.

2.7.3 AER final decision

As proposed.

2.8 Two stage process and likely alternative options

2.8.1 Proposed amendment

The NER now requires a two stage process for the selection of likely alternative options to proposed large transmission assets under the market benefits limb of the regulatory test.

This process consists of:

- seeking information on potential alternative options to the proposed large transmission network investment and
- identifying likely alternative options out of those potential alternative options.

In its November 2006 *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*[1] the AEMC explained that under this arrangement, the TNSP is to assess the proposal project against the ‘likely’ alternative or alternatives, rather than an assessment against all genuine and practicable alternatives.

To provide for this the AER proposed the inclusion of ‘likely’ in the market benefits test and introduced paragraphs 15-17 which set out some parameters in line with the NER on what NSPs should consider in determining whether a project is likely. The proposed regulatory test prescribed the following approach:

- The NSP gathers information on all options and determines which options qualify as an alternative options having regard to the requirements in the test.
- The NSP makes an assessment of which of these options is a “likely” alternative option having regard to the criteria in the test. The assessment of likelihood is to be consistent with the plain English meaning of likely.

1 AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006

- The NSP undertakes a market benefits assessment by comparing the probable net economic benefit of its proposed augmentation against that of the likely alternative options.

The AER considered that the regulatory test should reflect the AEMC's policy decision that:

> While a proponent would not be required for a project to be considered as a potentially likely alternative, the absence of a proponent could be one of the factors to be assessed in determining which alternative option or options are likely in the absence of the proposed project.[2]

A provision was included in the proposed regulatory test version 3 to give effect to this.

2.8.2 Submission

ETNOF has submitted that further guidance in relation to whether an option is 'likely' should be incorporated into the regulatory test and/or the accompanying guidelines. ETNOF considers this will ensure that the regulatory test meets the objective of it being capable of predictable, transparent and consistent application. ETNOF proposes that the criteria to be used to determine likelihood should be:

1. for a new large transmission network asset, whether the project has been proposed as a result of the RFI process. However, there should be no presumption that a project that has been proposed is therefore likely
2. whether the project has a proponent. However, the absence of a proponent does not by itself indicate that a project is not likely
3. whether the project is commercially feasible. ETNOF considers commercial feasibility is a relevant consideration in determining whether an option is likely. Further, ETNOF considers that if an option is commercially feasible, it may still be considered likely even in the absence of a proponent and
4. whether a project is considered to be anticipated as defined under paragraph 22 of the regulatory test.

ETNOF believes that its proposed criteria are consistent with the AEMC's intent that alternative options under the market benefit limb be 'likely' options and that these criteria will reduce:

- disruption and delay to the regulatory process by proponents proposing unrealistic alternatives and
- the likelihood that if the network alternative does not go ahead nothing will be built.

[2] AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006, p. 62

Further, ETNOF considers the proposed criteria also provide guidance for proponents of alternative projects as to what information they would need to provide in their responses to the RFI in order to be considered as likely alternatives.

2.8.3 AER final decision

The AER has carefully considered ETNOF's proposed criteria for the consideration of alternative options and agrees that there is merit in providing some further guidance around likelihood in the test.

After examining ETNOF's two additional criteria (3 and 4), the AER has decided that commercial feasibility is a relevant consideration in determining whether an option is likely. Commercial feasibility under the regulatory test version 2 is:

> .. to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide this alternative option.

The AER considers at the stage where a TNSP is identifying likely options out of alternative options, commercial feasibility would be an appropriate factor to consider.

In relation to the fourth proposed criteria, namely whether a project is anticipated, the AER notes that anticipated projects are defined in the regulatory test as any projects that are in the process of meeting one or more of the following criteria:

> (a) the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;
>
> (b) construction of the proposal must either have commenced or a firm commencement date must be set;
>
> (c) the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for construction of the proposed development;
>
> (d) contracts for supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and
>
> (e) the financing arrangements for the proposal, including any debt plans, must have been finalised and contracts executed.

The AER understands ETNOF's intention in proposing the inclusion of 'anticipated project' as a means of addressing potential gaming of the regulatory process through the proposing of unrealistic alternatives and the possibility that if the network alternative does not go ahead nothing will be built. However, on balance, the AER considers that the inclusion of commercial feasibility in combination with criteria 1 (there should be no presumption that a project that has been proposed is therefore likely) and 2 (whether the project has a proponent) already achieves this. Further, the criteria are for guidance only and are not exhaustive. If an NSP considers a proposed alternative option to be unrealistic, or questions whether it will go ahead, it is free to consider these factors as part of its assessment of likelihood.

In addition, the AER does not consider it appropriate to introduce the notion of anticipated projects into an assessment of likelihood as anticipated projects already form part of the 'reasonable scenarios' included in a regulatory test analysis. The AER considers that repeating the concept of anticipated projects in a judgement as to likelihood will confuse a regulatory test analysis.

The AER notes that the AEMC considered that 'likely' alternative options should be 'a real chance or possibility rather than a mere possibility.'[3] While the AER does not think it appropriate to include this in the regulatory test, it will include it in the application guidelines to assist further.

The AER has therefore decided to amend the proposed regulatory test version 3 to provide further guidance around whether a project is likely by including 'commercially feasible' as a factor of consideration. The AER has also slightly restructured the provision to make it clearer. The AER's amended criteria for likelihood are as follows:

(17) In determining whether an *alternative option* is likely for the purposes of any analysis in accordance with paragraph 1(b) of this test the *Network Service Provider* must:

(a) consider all *alternative options* without bias regarding:

(i) energy source;

(ii) technology;

(iii) ownership;

(iv) the extent to which the proposed network asset or non-network alternative enables intra-regional or intra-regional trading of electricity;

(v) whether it is a network or non-network alternative;

(vi) whether the option is intended to be regulated; and

(vii) whether the option or *alternative option* represents a combination of other options.

(b) consider whether the project has a genuine proponent. However, the absence of such a proponent will not in itself exclude a project from being a likely *alternative option* for the purposes of the *regulatory test*.

3 AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006, p 61

(c) consider whether the project is commercially feasible, which is to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide this *alternative option*.

(d) where the proposed asset is a *new large transmission network asset,*

(i) consider any *alternative options* proposed in the request for information process required by this test. However, there should be no presumption that a proposed project is likely and

(ii) include in any *regulatory test* analysis completed in relation to the proposed *new large transmission network asset*:

(I) a summary of any *alternative options* proposed in the relevant request for information process and

(II) detailed reasons as to why an *alternative option* was found to be likely or unlikely.

(18) Where there is more than one likely *alternative option* to the new *network* investment, and no single *alternative option* is significantly more likely to occur than the other, then the *market benefits* analysis required in accordance with paragraph (1)(b) of this test must be undertaken in relation to each such likely *alternative option*.

2.9 Request for information

2.9.1 Proposed amendment

The AER included a request for information (RFI) process and information requirements in the proposed regulatory test version 3 to satisfy its obligations under clause 5.6.5A(c)(4) of the NER which provides that the market benefits limb of the regulatory test must:

> require, for a potential new large transmission network asset, that the Network Service Provider publish:
>
> (i) a request for information as to the identity and detail of alternative options to the potential new large transmission network asset; and
>
> (ii) details of the proposed new large transmission network asset

The AER notes that, under the terms of the NER, this RFI requirement only applies to large transmission assets and not distribution.

The following RFI process was included in the proposed regulatory test version 3 for all new large transmission network assets under the market benefits limb. This process is an extension of the application notice process for new large transmission network assets in clause 5.6.6 of the NER.

(25) For the purposes of any analysis undertaken in relation to paragraph (1)(b) of this test, a *transmission network service provider* must publish a request for information notice for a potential or proposed *new large transmission network asset*.

(26) The request for information notice must request information as to the identity and detail of *alternative options* to the potential or proposed *new large transmission network asset*.

(27) The *transmission network service provider* must include the following information in the request for information notice:

(a) the details of any potential or proposed *new large transmission network asset* including:

(i) all of the relevant technical details, including asset type and project configuration;

(ii) the proposed construction timetable;

(iii) the commissioning date; and

(iv) all known expected *costs* and the likely sources of *costs* and *market benefits* associated with the proposed asset;

(b) the reasons for the potential *new large transmission network asset,* including how the potential asset satisfies these reasons and, where applicable, any network limitations, reliability requirements or specific planning criteria;

(c) known existing and planned infrastructure in the geographic region, including relevant transmission, distribution and generation assets;

(d) load forecasts in the geographic region for the next ten years including peak demand and load profiles;

(e) any specific project requirements that an *alternative option* must fulfil including any technical or other limitations such as:

(i) speed of demand side or generation response;

(ii) size, type and location of load(s) to be reduced, shifted, substituted or interrupted; and

(iii) size, type and location of generation to be installed or utilised; and

(f) a description of the process for assessing *alternative options* including evaluation criteria.

(28) At least 4 months before an application notice in relation to the proposed *new large transmission network asset* is published, the *transmission network service provider* must:

(a) publish the request for information notice on its website and

(b) provide the request for information notice to NEMMCO for publication on the NEMMCO website.

(29) The request for information notice must specify a due date for submissions which must be at least 8-12 weeks after the date the request for information notice is published on NEMMCO's website. The time allowed for submissions must be proportionate to the size and complexity of the proposed or potential *new large transmission network asset.*

(30) Interested parties may apply to the *transmission network service provider* to have the submission due date extended. This application must be made at the latest 4 weeks after the request for information notice is published on NEMMCO's website.

(31) Any person may make a written submission to the *transmission network service provider* in response to the request for information notice.

This RFI process was developed by reviewing the AEMC's rule determination, the amendments to clause 5.6.5A of the NER, existing consultation requirements in the NER, the voluntary RFI processes that some NSPs have recently implemented and, where applicable, relevant consultation requirements for DNSPs in each jurisdiction of the NEM.

The proposed RFI process:

- required TNSPs to publish an RFI notice at least 4 months before publishing the related application notice.
- required TNSPs to give interested parties between 8-12 weeks to respond to an RFI notice. In proposing this 8-12 week range the AER attempted to balance the needs of TNSPs and potential proponents.
- provided that an interested party may apply to the TNSP to have the due date for submissions extended. This application must be made no later than four weeks after the RFI notice is published on NEMMCO's website.

The AER set a minimum timeframe between issuing an RFI and application notice to assist in ensuring sufficient time for the consideration and implementation of alternative options.

The AER proposed the minimum 8 week submission period to provide respondents adequate time to gather information on an alternative proposal and prepare a meaningful alternative option which addresses the relevant matters raised in the RFI notice. Recognising a TNSP's desire to minimise procedural delays and regulatory costs, the AER provided for the submissions period to be determined by the TNSP within a 8-12 week range. As guidance, the proposed RFI process required that the time provided be proportionate to the size and complexity of the proposed or potential asset. The AER considered that this provided flexibility to the TNSP to set a submission period that suited the scale of the proposed investment or particular demands on an alternative option.

In addition, the amendments to the regulatory test included an extension process which would allow the TNSP to set a period for submissions, but then extend the period if interested parties who intend on proposing alternative projects need additional time to prepare their proposals. However, where there are no alternative proposals from interested parties, the period for submissions would not be extended and the delay caused by the RFI process would be minimised.

The AER's proposed amendments also require a TNSP to publish in its RFI notice:

- the reasons for the proposed or potential new large transmission network asset
- information on the proposed or potential asset including the technical details, the construction timetable all known costs and the likely sources of costs and benefits
- known existing and planned infrastructure in the geographic region, including relevant transmission, distribution and generation assets
- load forecasts in the geographic region for the next ten years including peak demand and load profiles
- any specific project requirements that an alternative option must fulfil and
- a description of the assessment process.

The AER's proposed amendments aimed to provide transparency and certainty in the RFI process by requiring TNSPs to inform proponents about their assessment process upfront. Proponents would also be provided with a description of how the TNSP considers that its proposal satisfies the reasons or need for the asset. The AER also argued that potential proponents should be provided with sufficient information on the TNSP's proposed or potential asset and its likely costs and benefits in order to provide a quality response and workable alternative option.

The proposed amendments to the regulatory test version 3 required the TNSP to include in any regulatory test analysis a summary of the alternative proposals suggested during the RFI process and detailed reasons as to why the TNSP determined that an alternative proposal was likely or unlikely. The AER argued that this will ensure that there is transparency in the regulatory test process and will provide proponents and participants in the market with greater confidence in regulatory test outcomes.

2.9.2 Submissions

Timeframes

The AER received submissions from ETNOF and Energy Response addressing the RFI process.

ETNOF submits that the proposed timeframes are overly prescriptive and only the submission period should be set out in the regulatory test. ETNOF considers the timeframe within which the TNSP issues its Application Notice following an RFI notice is a matter for each TNSP, and should depend on the extent of responses received to the RFI and the clarity of those responses.

ETNOF submits an 8-12 week timeframe for RFI responses is excessive and submits the consultation period for RFI responses should be a maximum of 30 business days, consistent with the time allowed for submissions on an Application Notice, consideration of submissions period, and Final Report dispute period. ETNOF also considers there should be no provision for extension to the submission period, in order to reduce the possibility of respondents delaying the process. However ETNOF believes that if the regulatory test does permit extensions to the submission period then it needs to provide more guidance and assessment criteria around the extension process.

In contrast, Energy Response, a demand side response aggregator, submitted that ideally the RFI process should be longer to allow for the establishment of contracting arrangements for the provision of demand side response solutions. However Energy Response submits that a period of 8-12 weeks is reasonable and that the RFI process as proposed will take greater account of the effort involved in organising and providing a viable non-network solution.

The AER also notes that Energy Response has raised issues with the current network support pass through arrangements and the delays to implementing network support options. Energy Response has suggested that NSPs should apply for pass through approvals at the same time they issue an RFI notice. Energy Response considers that:

> ..running these two processes in parallel will ensure there is approved funding for the project at the time that a decision is made of whether to accept a non-network solution. The NSP may need to “square up” the final amount to be passed through, but that should not impact on the process or timing leading to a contract for a non-network solution.

Information required in an RFI notice

ETNOF submits that the proposed requirements on information to be provided in an RFI notice go beyond what is contemplated by the NER and the AEMC’s rule determination. In particular, ETNOF has concerns about the AER’s proposal to require the inclusion of “all known expected direct costs and the likely sources of costs and market benefits associated with the proposed asset” in an RFI notice. ETNOF believes this provision could give rise to the following problems because:

- a full cost benefit analysis is unlikely to have been completed in the early RFI investigation stage. ETNOF recommends the cost information required be to a similar level of accuracy and detail as is provided in a TNSP’s APR; and
- release of cost information in relation to any proposed network asset and alternatives will place a TNSP at a commercial disadvantage when negotiating with potential providers of non-network options. ETNOF considers this could compromise a TNSP’s ability to deliver the truly lowest cost solution and would appear to be contrary to the NEM objective, as adopting a solution that was not the lowest cost solution would not be in the long term interests of electricity consumers.

Further, ETNOF notes that information obtained from the RFI process may be confidential, especially cost related information provided by third parties. ETNOF recommends that any confidential information used in the regulatory test analysis be treated in accordance with clause 8.6 of the NER.

2.9.3 AER final decision

Timeframes for RFI process

The AER has carefully considered the submissions received in relation to the proposed RFI process.

The AER notes ETNOF's objection to requiring an RFI notice be published at least 4 months prior to an application notice. ETNOF argues that this unnecessarily constrains the TNSP into making decision about alternative options within a certain timeframe following the RFI process.

The AER considers that a minimum timeframe between issuing an RFI and application notice might assist in ensuring sufficient time for the consideration and implementation of alternative options. However, the AER understands that realistically, prescribing this timeframe cannot in itself guarantee the genuine consideration of alternative options. This is a matter largely up to TNSPs themselves and the AER agrees with ETNOF's point that the appropriate time period to consider responses and alternative option proposals depends on the particular circumstances of the proposed investment and the RFI responses received. Further, the AER recognises the inherent problems that arise from over-prescription of process and the need to provide flexibility.

The AER therefore has decided to not include a specification in the regulatory test version 3 that an RFI notice must be published at least 4 months ahead of an application notice. However, the AER encourages TNSPs to establish planning practices that ensure appropriate time is allocated for the consideration of RFI responses and any alternative options. The AER expects that a TNSP will properly consider RFI responses and any alternative options before preparing its application notice in a commitment to best-practice transmission planning.

The AER has considered Energy Response's submission on running the RFI and network support tender process in parallel. While the AER considers that any pass through arrangements should be practicable and facilitate the timely implementation of quality network support options, the pass through process lies beyond the scope of this review. The AER would welcome any initiatives by policy-makers to consider issues around consistency between the regulatory test results and the timely implementation of network support options.

Extensions and timeframe for submissions

ETNOF submits there should be no provision for an extension to the submission period, in order to reduce the possibility of respondents delaying the process. The AER has considered this issue and notes that the extension option was to provide flexibility to the TNSP and non-network option proponents in cases where it would be necessary. The AER notes that such an extension for submissions was provided by CitiPower in its Melbourne

CBD upgrade consultation process.[4] The AER considered that a provision for extensions to the submission period would provide valuable flexibility to the RFI process. However, the AER acknowledges that if a TNSP is genuinely seeking viable alternative options, and it becomes clear that a proponent of a potential alternative option needs additional time to provide a response, the TNSP would provide extra time for submissions of its own accord.

In light of this, and recognising the importance in avoiding procedural over-prescription, the AER has decided to not include an express provision for any extension to the timeframe for submissions. This provides TNSPs with the discretion to judge if the minimum timeframe is insufficient. However, the AER expects that a TNSP would consider providing an extension for submissions if it becomes aware that a proponent requires extra time to provide a workable and valid alternative option. This would demonstrate a genuine commitment to finding the best option to address the identified network/market need.

The AER has considered ETNOF's proposal to shorten the submission period to 6 weeks, and Energy Response's submission that it would ideally be longer. ETNOF has submitted that the 8-12 week timeframe is excessive. Energy Response has submitted that the time provided for submissions should be longer than 8-12 weeks, but that the proposed timeframe seems reasonable.

The AER notes ETNOF's argument that the RFI submission period should mirror the timeframes allowed for consultation on: the preliminary regulatory test analysis in an Application Notice; the preparation of a final regulatory test report; and the timeframes for disputes to be brought in relation to a Final Report finding. However the AER considers there is a significant difference between responding to a preliminary regulatory test assessment in an application notice and preparing an alternative solution to a proposed network augmentation. The latter requires a greater amount of time as it will involve preparing a solution that meets a number of technical and cost requirements that will inform the option analysis in a regulatory test assessment. Given that the NER requires an alternative option be 'likely' in order to warrant consideration and inclusion in the substantive analysis, any alternative option proposed in an RFI process needs to be fully scoped and supported to meet this higher hurdle. As it is reasonable to distinguish between submissions on application notices and submissions to RFI notices, it is also reasonable to distinguish between the time provided for these. The AER therefore does not accept the proposal that these periods should be equal.

As stated in its explanatory statement, the AER has reviewed existing consultation requirements for DNSPs and the voluntary processes NSPs have conducted in formulating the RFI submission period. The AER notes that in South Australia, the Essential Services Commission of South Australia (ESCOSA) has established a request for proposals process for network augmentations valued over $2 million that mandates a minimum of 6 months for responses.[5] In New South Wales (NSW) the Department of Water and Energy (formerly

[4] CitiPower's *RFP 001/06* for a Security Upgrade to Melbourne's CBD provided 9 weeks for submissions and this deadline was extended by a further 3 weeks to allow potential proposals to be completed. See NERA, *Melbourne CBD Enhancement: Regulatory Test Analysis*, April 2007.

[5] ESCOSA, *Demand Management for Electricity Distribution Networks Electricity Industry Guideline No. 12*, July 2007.

the Department of Energy Utilities and Sustainability) has a demand management code of practice[6] which provides guidance to DNSPs on how to meet their licence obligations. This code provides that a NSW DNSP should allow a minimum of 8 weeks for responses to a request for proposals.[7]

A review of voluntary processes conducted by NSPs has revealed that the time provided for the collection of information on alternative options can range from 4 weeks to 12 weeks. In a few cases where an NSP has issued a request for proposals for a major network augmentation the NSP has provided up to 12 weeks for responses. For example, for its Newcastle-Sydney-Wollongong Area project, TransGrid published a ‘Needs Statement’ which sought, and set out relevant requirements for, alternative solutions before the preparation of its application notice. TransGrid allowed nearly 8 weeks for responses to this Needs Statement and provided a further 4-week period for submissions on non-network options following the publication of the application notice.[8] These 12 weeks of consultation were additional to the minimum 6 weeks for submissions to an application notice. Similarly, CitiPower provided a total of 12 weeks for responses to its request for proposals issued for its proposed security of supply upgrade in the Melbourne CBD.

The AER considers that an adequate amount of time is essential for proponents to provide quality alternative option proposals. The AER notes that the AEMC stated:

> The RFI process would be transparent and encourage interested parties to propose workable, commercial alternatives to a proposed network investment... in its promulgation of the Test, the AER should include appropriate guidance as to the operation of the RFI process.[9]

The AER considers that 6 weeks would be an inadequate amount of time for the preparation of a quality response and would discourage the proposal of workable non-network alternatives. Having regard to the submission timeframes required in South Australia and NSW, the voluntary processes which have recently been undertaken in relation to proposed large network investments, and its understanding of the time required to put a workable alternative option together, the AER does not consider its 8 week minimum submission period for large transmission projects to be excessive. Further, the AER considers 8 weeks would not unduly delay the regulatory test process.

Whilst the AER acknowledges Energy Response’s preference to lengthen the timeframe provided for responses to an RFI notice, the AER does not consider providing a longer

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6 Department of Energy Utilities and Sustainability, *Demand Management for Electricity Distributors: NSW Code of Practice*, September 2004.

7 The Specification Protocol defines a Reasonableness Test which the distributor should apply in deciding whether to issue a formal Request for Proposals in relation to each constraint. This test states that the where the total annualised cost of addressing the system constraint is likely to be greater than $200,000 in a single year, then a RFP should normally be issued.

8 TransGrid, *Emerging major transmission network limitations in supplying the Newcastle- Sydney-Wollongong area- Needs Statement*, September 2005 and TransGrid, *RFP 104/06 Non-network solutions in the Newcastle-Sydney-Wollongong Area*, August 2006.

9 AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006, p59

timeframe to be possible due to the broader regulatory test consultation process which follows an RFI process. The AER considers a minimum 8 week timeframe provides an adequate period of time for submissions on alternative proposals. Further, the AER anticipates that in practice proponents may be made aware of the proposed asset before the RFI notice is issued. The TNSP will most likely provide information on the proposed new large transmission network asset in its APR. Where this occurs, potential proponents can begin considering alternative proposals.

No submissions commented on the flexibility provided in setting a range for submission timeframes instead of a minimum. Following consideration of the need to avoid procedural over-prescription, the AER has decided to remove this range and simply set a minimum of 8 weeks. Similar to the lack of an extension provision, this provides TNSPs with the discretion to judge if the minimum timeframe is insufficient. However, the AER expects that a TNSP would consider providing additional time if it is made aware this is required for the proposal of a workable and valid alternative option. This would demonstrate a genuine commitment to finding the best option to address the identified network/market need.

The AER considers that the minimum 8 week timeframe fits well into the broader regulatory test consultation process and balances the need to provide sufficient time for the preparation of quality workable alternative options whilst minimising procedural delay. The AER notes that an 8 week submission period reasonably reflects common practice in request for proposals/information processes. The regulatory test version 3 therefore sets out that the period for submissions to an RFI notice must be a minimum of 8 weeks but notes that it may be more, having regard to the scale and complexity of the proposed investment.

Information requirements for an RFI notice

The AER has considered ETNOF's contention that the proposed requirements on information to be provided in an RFI notice go beyond what is contemplated by the NER and the AEMC's rule determination.

For a new large transmission network asset proposal to proceed under the market benefits limb clause 5.6.5A(c)(4) of the NER requires the TNSP to publish:

> (i) a request for information as to the identity and detail of alternative options to the potential new large transmission network asset; and
>
> (ii) details of the proposed new large transmission network asset

In addition the AEMC's rule determination stated that:

> an RFI should set out, in a transparent manner:
>
> - the nature of the network limitation(s) that the regulated network investment and any alternative investment is intended to address;
> - the timeframe over which the investment is likely to be required; and

- any other supporting information that potential investors may require to prepare their responses.[10]

The AER considers ETNOF's concerns about the requirement for 'all known expected costs and the likely sources of costs and market benefits associated with the proposed asset' to be included in an RFI notice to be unfounded. The AER understands that a full cost benefit analysis is unlikely to have been completed in the early RFI investigation stage. Hence the provision only requires 'known' expected costs and market benefits to be disclosed - any unknown costs and benefits cannot be expected to be included.

The AER does not accept ETNOF's proposal to set the information requirements of an RFI notice to a similar level of accuracy and detail as is provided in a TNSP's APR. This would result in a duplication of the information in the APR with no additional value to the regulatory test analysis. The AER considers that the APR would provide information to the market about upcoming proposed network augmentations and the RFI notice would provide fuller details on specific augmentations to potential respondents. This will facilitate a fuller consideration of alternative options, particularly non-network options.

The AER does not consider that the release of cost information in relation to any proposed network asset and alternatives is unreasonable. It is common practice to include project costings in a request for proposals notice in order to provide potential respondents with the ability to compare whether or not their alternative options would be cost effective. The AER does not consider providing costings in an RFI notice would compromise a TNSP's ability to deliver the truly lowest cost solution by placing the TNSP at a commercial disadvantage when negotiating with potential providers on non-network options. If a TNSP considers that an alternative option is costed incorrectly in order to secure a higher ranking in the regulatory test analysis, it is always free to require additional costing information before conducting its regulatory test analysis. Further, the proponent of a non-network solution would need to prove the veracity of its costings for the TNSP to consider it commercially feasible and 'likely'. It is also up to individual TNSP to check costings before implementing a non-network solution and making a network support agreement.

The AER therefore has decided to maintain the information requirements as set out in the proposed regulatory test version 3. The AER considers that the proposed information requirements for RFI notices give effect to the AEMC's decision and satisfy the broad intent of clause 5.6.5A(c)(4) of the NER.

The AER agrees that confidential information obtained from the RFI process (particularly cost related information provided by third parties) should be treated in accordance with the clause 8.6 of the NER. The AER has decided to set this out in the application guidelines.

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10 AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006, p. 59

2.10 Determining costs and benefits

2.10.1 Proposed amendment

Clause 5.6.5A(c)(2) of the NER requires that in relation to the market benefits limb, as a minimum, the regulatory test must list or provide for:

> (i) the classes of possible benefits that may be included as benefits, and classes of possible benefits that may not be included as benefits;
>
> (ii) the method or methods permitted for estimating the magnitude of the different classes of benefits;
>
> (iii) the classes of possible costs that may be counted as costs, and classes of possible costs that may not be included as costs;
>
> (iv) the method or methods permitted for estimating the magnitude of the different classes of costs; and
>
> (v) the appropriate method and value for specific inputs, where relevant, for determining the discount rate to be applied.

In relation to subclause (v) the AER decided that it is inappropriate for a regulator to prescriptively set out the method and value for specific inputs for determining the discount rate to be applied in market benefits assessments and sensitivity analysis.

The AER also proposed a revision to the test to reflect the fact that cost allocation principles are set out in clause 6A.19.2 of the NER.

2.10.2 Submissions

Discount rate

The Major Energy Users Inc (MEU) has submitted that:

> the discount rate to be applied in preparing net present values for future cash flows should be re-addressed, so that the rate is more attuned to the way consumers are impacted by electricity system costs and prices, rather than allowing a discount rate to be greater than the WACC used for the reset of revenue.

The MEU is concerned that a discount rate higher than the weighted average cost of capital (WACC) would provide inappropriate outcomes and that a higher discount rate will create a bias in the analysis towards projects with low current but higher/positive continuing costs such as a network support solution compared to a larger current but once-off cost such as a network augmentation.

The MEU recommends the regulatory test should prescribe a discount rate set in terms of the costs consumers face, such as the consumer price index (CPI). The MEU considers this would provide greater transparency in the relationship between the future costs incurred for the network in terms of the way consumers see network costs change.

Cost allocation

The proposed regulatory test requires that in determining costs or benefits, cost allocation by DNSPs must be consistent with the relevant distribution ring-fencing guidelines. EnergyAustralia has submitted that in NSW, cost allocation is addressed in the Independent

Pricing and Regulatory Tribunal's (IPART's) Regulatory Information Requirements, not ring-fencing guidelines.

2.10.3 AER final decision

Discount rate

The AER has considered the MEU's submission that the discount rate used in calculating net present values for the purposes of a regulatory test analysis should be lower than the regulated rate of return for the NSP.

The AER does not accept the MEU's proposal. Firstly, neither private investors nor consumers have access to a social discount rate when making their own borrowing and spending decisions. Using a social discount rate for only one type of investment in the market – investment in the network or non-network options – would create a bias in favour of investment by TNSPs ahead of all other competing purposes. Specifically, it could mean that NSPs systematically pre-empt investment by actual and prospective participants. Wherever an option involves high up-front costs, the regulatory test would find it optimal for NSPs to develop that option (whether network or non-network) ahead of when that option would otherwise be developed.

Secondly, the AER notes that the regulated rate of return (WACC) is set as a lower boundary for the discount rate in sensitivity analysis. If the MEU considers the WACC is too high, the AER notes that stakeholders will have the opportunity to affect the setting of WACC parameters in the AER's review of the WACC scheduled for 2009.

The AER maintains that the most important issue is that the discount rate used recognises regulated and unregulated investments in a competitively neutral manner. The discount rate should be determined by the business proposing an option and the inputs into a discount rate are a matter left to the financial markets to determine, not the AER.

The AER has therefore decided to retain the current provision in the test which requires the discount rate used to be consistent with that of a private commercial enterprise in the electricity market and that it match the type of cash flows being discounted. The AER has retained the WACC as the lower boundary for discount rate used in any sensitivity analysis.

Cost allocation

The AER notes EnergyAustralia's point about cost allocation not being addressed in NSW's ring fencing guidelines. The AER has therefore decided to broaden the language in this provision to cover situations such as that in NSW where cost allocation is governed by an information requirement guideline.

The AER therefore revises the provisions dealing with cost allocation to state that the allocation of costs or benefits to be consistent with the 'relevant jurisdictional guideline'. The provisions now read:

(10) Any cost or benefit which cannot be measured as a cost or benefit to producers, distributors and consumers of electricity may not be included in any analysis proposed in accordance with this test. The allocation of costs and benefits between the electricity and other markets must be based on

principles consistent with the cost allocation principles in clause 6A.19.2 of the NER in the case of transmission, or consistent with the relevant jurisdictional guideline in the case of distribution.

(11) In determining the *costs* or *market benefits*, it should be considered whether the proposed option will enable:

(a) a Transmission Network Service Provider to provide both prescribed and other services; or

(b) a *Distribution Network Service Provider* to provide both prescribed distribution services and other services.

If it does, the *costs* and *market benefits* associated with the other services should be disregarded. The allocation of costs between prescribed and other services must be consistent with the cost allocation principles in clause 6A.19.2 of the NER. The allocation of costs between prescribed distribution services and other services must be consistent with the relevant jurisdictional guideline.

3 Clarification amendments

3.1 Introduction

The AER has decided to make a number of amendments which simplify or improve the clarity of the test based on recent experience. This section outlines a number of amendments that clarify those elements of the regulatory test which are ambiguous or overly prescriptive and simplify those elements which are unnecessarily complex or prescriptive.

Where a submission has been made on a particular amendment this determination sets out:

- a summary of the submission and
- the AER's final decision on the proposed amendment including its response to submissions and any considerations.

The AER has retained proposed revisions that are uncontroversial.

3.2 Costs

3.2.1 Proposed amendment

The AER proposed an amendment to the definition of costs to improve its clarity and consistency with the remainder of the test. Specifically, the AER considered the definition of costs should be simplified to mean the direct costs of an option (ie capital costs, operating costs, etc), rather than the total costs of an option to all NEM participants.

Version 2 of the regulatory test defines *costs* as

(2) .. the total cost of an option (or an alternative option) to all those who produce, distribute or consume electricity in the National Electricity Market.

In determining the costs, the analysis may include, but need not be limited to, the following:

(a) costs incurred in constructing or providing the option;

(b) operating and maintenance costs over the operating life of the option;

(c) the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution (including greenhouse gas abatement). An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost.

(d) other costs that are determined to be relevant to the case concerned.

Paragraph 2(d) may have been originally intended to capture costs that are similar in nature to those referred to in paragraphs (a)-(c). However, it appears that (d) has been construed by some NSPs as including some of the negative consequential impacts of an option on the market as a whole (such as transmission losses). In its proposed amendments to the regulatory test, the AER concluded that such ‘indirect’ or ‘market’ costs ought to be excluded from the definition of costs for the purposes of both limbs of the test because:

- under the reliability limb, the regulatory test analysis is required to demonstrate that the option chosen is the least cost option to meet minimum reliability requirements. ‘Cost’ in this context should be interpreted as the direct project costs in providing that option in order to preserve the distinction between the cost-minimising criterion applied under the reliability limb and the broader market benefits criterion applied under the market benefits limb. Explicitly limiting the definition of costs to direct project costs and removing the concept of costs being total costs to all producers, transporters and consumers of electricity (ie market costs) makes this intention clear.

- under the market benefits limb, the regulatory test analysis is required to demonstrate that an option is net beneficial (ie maximises the net economic benefit) taking into account both direct and indirect (or market) costs. This means the regulatory test first nets off market costs to derive market benefits and then nets off the (direct) *costs* of an option to arrive at the final *net economic benefit* of that option. Given this netting off, it is important for the sake of avoiding double-counting for the definition of *costs* to exclude market costs.

The AER recognises that some NSPs may be interpreting the current definition of costs in the test to take account of the effect of an option on the (direct) costs of other transmission and distribution network projects that may be required in the future. TNSPs have thus been undertaking a partial cost-benefit analysis under the reliability limb in a way to minimise the forward-looking long term capital and operating costs of planning and running their networks, and have not just been selecting the project that has the lowest direct costs. The AER is concerned that given that most of the transmission investment in the NEM is justified on a reliability basis, such a partial approach may lead to significant distortions in network planning decisions. The AER sought views on the extent of such potential distortions.

The AER’s proposed regulatory test version 3 and application guidelines featured a clarification (rather than a deliberate narrowing) to the definition of costs which removed:

- ‘to all those who produce, distribute or consume electricity in the NEM’ and
- catch-all paragraph 2(d).

The AER considers that this revision is consistent with the NER and the AEMC's determination, and that it removes any ambiguity on this issue. The proposed revision also ensured that the direct costs of a project would not be double-counted in the application of the regulatory test to options under the market benefit limb.

In its explanatory statement, the AER explained that this revision should not be interpreted as preventing NSPs from including future network cost implications in a reliability limb assessment. As explained in the proposed application guidelines, where an option consists of more than one individual project, the costs of the option includes the costs of all of those projects. The application guidelines stated that all the projects to be combined to form an option should have anticipated commissioning dates within a reasonable timeframe of the regulatory test assessment, such as within 5-10 years. Further, any option that is formed by a combination of projects ought to be compared against comparable alternative options, which may themselves be formed by a combination of projects.

The AER noted that it anticipates that the above issue may be resolved in the upcoming work by the AEMC to integrate the two limbs of the test.[11] In the meantime, the regulatory test must remain consistent with the NER which does not contemplate a partial cost-benefit approach for the reliability limb. As such, the AER proposed to remove the catch-all provision from the definition of costs.

The AER clarified that if other network costs (those not directly related to the option or alternatives under consideration) were to be included in a reliability limb assessment, the analysis should also include all relevant market costs, such as the impact of an augmentation (or alternative) on generation fuel and capital costs. In such cases it would be more appropriate to assess the proposed or potential investment under the market benefits limb of the test.

In addition, the AER considered that paragraph 2(c) of the current test is unnecessarily detailed and prescriptive. It currently reads:

> the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution (including greenhouse gas abatement). An environmental tax should be treated as part of a project’s cost. An environmental subsidy should be treated as part of a project’s benefits or as a negative cost.

The AER argued that there is sufficient flexibility in the test to accommodate all the different regulatory and legal costs in providing an option without having to include this level of detail. The AER proposed simplifying this paragraph to state that costs include the cost of complying with laws, regulations and applicable administrative requirements in relation to the option.

3.2.2 Submissions

Direct costs

The AER received a number of submissions on its proposed revision to the definition of costs for the test.

ETNOF and Energy Australia submit that the list of costs should also include a reference to the incremental cost of electrical losses associated with an option compared to the alternatives, where this cost is considered to be material and has not been taken into account elsewhere in the analysis. Energex has submitted that any option analysis under the regulatory test should take into account transmission losses.

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[11] This work has officially commenced following the AEMC’s publication of a Scoping Paper on 3 August 2007.

ETNOF considers that in some cases a failure to consider the cost of losses associated with alternative options would result in sub-optimal investment decisions. ETNOF submits that to ignore the impact of a particular network option on future transmission constraints under the reliability limb of the regulatory test would not be consistent with minimising the long term capital and operating costs of the networks. This has the potential to result in sub-optimal investment decisions and is inconsistent with the NEM objective. ETNOF is concerned that the AER's 'clarification' of the definition of the costs of an option will prevent the consideration of losses in cases where differences in losses will have a material impact on the outcome of the regulatory test assessment. ETNOF therefore proposes that the regulatory test retain the catch-all provision which allows TNSPs to include the impact of an option on the cost of losses under the reliability limb, in circumstances where this cost may be material to the outcome of the assessment.

Energy Australia contends the AER has no express head of power to specify what costs can or cannot be included under the reliability limb. Energy Australia also considers that the proposed revision to the definition of costs is inconsistent with the NEM objective, the NER and the AEMC's scoping paper on the national transmission planner. Energy Australia has proposed the following drafting changes to the definition of costs:

> (2) Costs of an option (or an alternative option) may include:
>
> (a) direct costs incurred in constructing or providing the option
>
> (b) operating and maintenance costs over the operating life of the option and
>
> (c) the cost of complying with laws, regulations and applicable administrative requirements in relation to the option.

Energy Australia submits that the limitation of costs to direct costs will negatively impact its distribution investments.

Energex submits that it 'does not see the rationale for the exclusion of the cost of losses in option analysis.' The AER assumes that this comment is only in relation to the reliability limb, as the market benefits limb accounts for transmission losses.

Recognising the cost of related future investments

The AER has received submissions responding to its proposal that where an option consists of more than one individual project, the costs of the option include the costs of all of those projects.

ETNOF has concerns in relation to defining an option as incorporating a stream of future network investments, which would allow the overall cost of all network investments in a stream to be assessed. ETNOF considers this raises a practical issue in relation to the degree of commitment implied to a later component of an option, if that option is determined to have satisfied the regulatory test.

> ETNOF believes that it would be neither practical nor consistent with the NEM objective for a TNSP to be deemed to have necessarily committed to all components of an option that satisfies the regulatory test where that option is made up of a stream of investments over a significant period of time.

> It is only the earlier components of an option that a TNSP would definitely set out to construct. Later components may be subject to further assessments closer to the times that those components are required, in order to determine that they are still the most efficient investments, given the circumstances at the time…

ETNOF recommends a clarification to the regulatory test (or in the application guidelines) that the option is only the initial investments and not the entire stream of investments. The later components need to be included in the economic comparison but be referred to as modelled projects and not form part of the recommended works of that option. The TNSP is then only committing to undertaking the earlier components where it has satisfied the regulatory test.

Complying with laws

ETNOF notes that the AER's revisions to paragraph 2(c) which refers to the cost of complying with laws, regulations and applicable administrative requirements has removed a reference to environmental subsidies being treated as part of a project's benefits or as a negative cost. ETNOF considers that:

> ..this reference should be maintained in order to preclude any dispute as to whether an environmental subsidy should be included in the assessment of a project's cost under the reliability limb of the test. In the absence of this reference the concept of including a subsidy as a 'negative cost' may be questioned.

Non-network option costs

ETNOF proposes that paragraph 2 which sets out the definition of costs should include a reference that where there is a proponent for a non-network option, the costs for that non-network option should be based on the price in the proponent's offer for network support, rather than an independent estimate based on resource input costs. ETNOF considers that this approach is consistent with current practice under the regulatory test and has previously been confirmed as the AER's preferred approach to estimating the cost of non-network options.

3.2.3 AER final decision

Direct costs

The AER has given careful consideration to the points raised by NSPs on the proposed clarification to the definition of costs under the regulatory test. In the proposed regulatory test and application guidelines, the AER proposed clarifying that 'costs' were limited to the direct costs of providing or operating the relevant option.

On the threshold issue of whether the NER allows the AER to prescribe the types of costs and benefits that may be included in a regulatory test assessment, clause 5.6.5A(c)(2)(i) and (iii) of the NER explicitly requires that the regulatory test lists or provides for classes of costs and benefits that may, and may not be included under the market benefits limb. While the NER does not go into detail on how the reliability limb is to be formulated, it is within the AER's discretion to draft the reliability limb as it considers appropriate as the developer of the test. The AER considers that going into a similar level of detail about costs to be included under the reliability limb goes toward fulfilling the NER requirement that the test be capable of predictable, transparent and consistent application. Given that the AEMC's rule determination on the regulatory test principles supported the existing limited scope of assessment under the reliability limb,[12] the AER believes that amendments to clarify that interpretation of the test are within the scope of its present role.

The more difficult question is whether the definition of costs ought to be broader than direct costs. The reliability limb is specifically aimed at proposed investments that are driven by the NSP's statutory obligations and reliability requirements. The AER notes the reliability limb was retained in version 2 of the regulatory test as a 'least cost' test in recognition of NSP's unavoidable reliability obligations. The ACCC noted in its 2004 *Review of the Regulatory Test Draft Decision* that:

> the reliability limb of the regulatory test has the effect of bringing forward proposed augmentations.. compared to the market benefits limb.[13]

Given the purpose and general effect of assessing investment under the reliability limb, the AER considers that its changes to the definition of costs simply clarify policy-makers' original and current intent regarding the test – that assessments under the reliability limb are narrower than assessments under the market benefits limb.

Both the EnergyAustralia and ETNOF submissions commented that the limitation of costs under the reliability limb to direct costs could lead to sub-optimal investment decisions, which would be contrary to the NEM objective.

ETNOF's submission on the proposed regulatory test focuses on transmission losses, provided an example showing how greater up-front capital investment in an augmentation option could lead to lower losses – and hence a higher present value – than an option with lower up-front costs.

Elsewhere ETNOF acknowledges that transmission losses fall outside the 'costs' of an option. In its submission to the AEMC on national transmission planning arrangements ETNOF stated:

> Beyond such a safe harbour provision, it should be possible to include broader market benefits in the assessment as offsets against the costs of network and non-network alternatives. For example, additional savings in transmission losses or network support costs could be weighed up against the cost of advancing a network development to be earlier than would be required to meet the network performance need. If these incremental market benefits exceed the incremental costs of an option then that option should be considered to have satisfied the Regulatory Test, notwithstanding that the total costs may exceed the total benefits.[14]

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[12] AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006, pp.40-41.

[13] ACCC, *Draft Decision- Review of the Regulatory Test for Network Augmentations*, March 2004, pp 39-40

[14] ETNOF, *National transmission planning arrangements- Response to scoping paper*, September 2007, p 10

The question, then, is whether the reliability limb of the regulatory test should simply minimise costs, or take into account market benefits. ETNOF's discussion about transmission losses provides a good example of the limitations of a partial cost-effectiveness analysis under the reliability limb.

ETNOF's concerns would be addressed by a full market benefits assessment. However, this is not what ETNOF is proposing. Instead ETNOF proposes a partial assessment, which includes transmission losses but not other market benefits. This may result in different, or less efficient outcomes than a straightforward cost minimisation exercise. For example, there appears to be no dispute amongst stakeholders that the reliability limb does not involve specific consideration of the additional power transfer capability than a network augmentation may provide. Such an increase in capability could allow the dispatch of lower-cost generation in place of higher-cost generation, thereby reducing the resource costs of serving load. Yet from an economic efficiency perspective, there is little difference between surpluses arising from lower network losses and surpluses arising from the dispatch of cheaper generation.[15] Both yield resource cost savings (or market benefits) from a NEM-wide perspective. The only difference is that lower network losses increase surpluses through the need to dispatch a smaller quantity of generation (in MWh) to meet a given level of demand, whereas lower-cost dispatch produces resource cost savings through a change in the mix of dispatched plant. Taking into account only the impact of an option on network losses would bias the analysis under the reliability limb in favour of options that resulted in lower losses against those options that resulted in a more efficient pattern of dispatch. This would be arbitrary as well as contrary to policy-makers' stated intent.

The problems associated with a partial cost benefit assessment have been recognised by the ACCC and AEMC. In its 2004 *Review of the Regulatory Test for Network Augmentations Final Decision* the ACCC noted that the treatment of losses due to power flows is more appropriately considered as a market benefit. It was therefore removed from the definition of costs.[16] In its rule determination the AEMC explicitly considered and rejected a proposal from ETNOF to allow the reliability limb be able to (optionally) consider the impact of a project on market benefits, rather than consider only the "the pure lowest cost solution."[17]. The AEMC took the view that this would be a substantial modification to the application of the regulatory test and hence beyond the scope of its task. The AEMC acknowledged that the current 2-limb structure of the regulatory test is imperfect but clearly considered that the existing reliability limb only focuses on the direct costs of an option.[18]

The issues raised by ETNOF would be addressed by including an assessment of all market benefits. However, in its Final Rule Determination, the AEMC drew a strong link between

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15 Assuming alignment between generator offers and underlying resource costs.

16 ACCC, *Final Decision- Review of the Regulatory Test for Network Augmentations*, August 2004, pp 43-44

17 AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006, p 39

18 Ibid, pp 39-41

the obligations of NSPs to invest in a timely manner to maintain system reliability and the NEM objective. The AEMC was particularly concerned that

> …an overly complex or onerous Test may act to delay necessary reliability investment and therefore jeopardise the ability of NSP to meet their mandated reliability requirements.[19]

Thus the AEMC noted the potential tension between the maximisation of economic efficiency, which may require a more detailed assessment, and the timeliness of investment to meet reliability and security objectives. The AEMC went on to suggest that potential bias arising from application of the reliability limb should be the subject of a more comprehensive review following the recommendations of the ERIG report and COAG decisions. The AER agrees with the AEMC's assessment and considers that the proper treatment of different types of costs could be resolved through the AEMC's work on integrating the two limbs of the test.[20]

The AER considers that in the meantime, the regulatory test must remain consistent with the NER which does not contemplate a partial cost-benefit approach for the reliability limb. As such, the AER has decided to retain the definition of costs as set out in the proposed regulatory test version 3.

Recognising related future investments

The AER noted in its Explanatory Statement[21] and application guidelines[22] an option could be comprised of more than one project. The AER reiterates that where an option consists of more than one individual project, the costs of the option includes the costs of all of those projects. Further, any option that is formed by a combination of projects ought to be compared against comparable alternative options, which may themselves be formed by a combination of projects. This clarification accommodates NSPs' preference to assess options under the test in a way that would allow for the minimisation of the forward-looking (direct) costs of network development.

The AER has carefully considered ETNOF's concerns in relation to defining an option as incorporating a stream of future network investments. The AER considers that if future network augmentations are viewed as component projects of 'the option' being assessed under the regulatory test, the NSP should definitely be viewed as committing to those future investments. If this raises practical issues then the NSP is free to treat those future projects as 'modelled' or 'anticipated projects.' Where later projects are treated in the analysis as modelled projects, they will be used consistently in the regulatory test analysis and not form part of the components of that option. In such cases it would be clear that the

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19 AEMC, *National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006 – Final Rule Determination*, November 2006, p 39.

20 Ibid, p. 36.

21 AER, *Explanatory Statement- Proposed Regulatory Test version 3 and Application Guidelines*, July 2007, pp. 35-36.

22 Section 3.

NSP is only committing to undertaking the projects which have satisfied the regulatory test, and not those that have been used in developing reasonable scenarios.

The AER disagrees with ETNOF's view that it would be neither practical nor consistent with the NEM objective for an NSP to be deemed to have necessarily committed to all components of an option that satisfies the regulatory test where that option is made up of a stream of investments over a significant period of time. The regulatory test is a test for economic efficiency- if an option is formulated in such a way that satisfies the test, then an NSP is not then free to pick and choose which parts of the best option it will implement.

The AER recognises that it will depend upon the individual circumstances of the analysed options as to which later projects need to be included in the economic comparison and considers that the component projects of an option would be self-evident having regard to the drivers behind the option. However the AER considers that a boundary around relevant projects cannot be prescribed.

AER has therefore decided against ETNOF's recommendation to include a direction in the regulatory test (or in the Application Guidelines) that the option is only the initial investments and not the entire stream of investments.

Complying with laws

The AER has considered ETNOF's proposal to retain the current reference to environmental subsidies being treated as part of a project's benefits or as a negative cost. The AER considers that there should be no dispute as to whether an environmental subsidy should be included in the assessment of a project's cost under the reliability limb of the test. However the AER considers the treatment of environmental subsidies as negative costs would be more appropriately placed in the application guidelines. The AER has therefore moved this reference from the test to the application guidelines to assist in the understanding of the test.

Non-network option costs

The AER has considered ETNOF's proposal the definition of costs should include a reference that where there is a proponent for a non-network option, the costs for that non-network option should be based on the price in the proponent's offer for network support, rather than an independent estimate based on resource input costs.

The AER agrees in principle that this is the best method of estimating the cost of non-network options. However, in practice the commercial tender process for network support services is often not conducted in parallel to the RFI/regulatory test process - NSPs and non-network option providers may negotiate terms for network support after the regulatory test process has been completed. This means that the project details and costs which are used for offers for network support may differ from those provided at the RFI stage. While it is preferable that the costs of the network support option implemented aligns with the costs provided during the regulatory test process, it is difficult to guarantee this result given that a firm price for network support may not be available until after a regulatory test analysis has been completed.

The AER therefore has decided to not accept ETNOF's suggested revision. However, the AER has included a provision in the application guidelines stating that where a non-network option is proposed during the RFI process, to the extent possible, the costs used should reflect those that could be expected in a tender process for network support services.

3.3 Market Benefits

3.3.1 Proposed amendment

The AER proposed to amend the regulatory test definition of market benefit and the list of benefits that may be included as market benefit to make these simpler and more precise.

The AER proposed consequential amendments to ensure that direct project costs are not double counted as both costs and net benefits- market benefit does not include the costs defined in the test (direct project costs).

In addition to these amendments, the AER reduced the level of detail in the list of benefits that may be included in a market benefit analysis. The current regulatory test includes under paragraph 5:

> …
>
> (b) changes in voluntary load curtailment caused through reduction in demand-side curtailment;
>
> (c) changes in involuntary load shedding caused through savings in reduction in lost load, using a reasonable forecast of the value of electricity to consumers, or deferral of reliability entry plant;
>
> …

The AER has simplified the above paragraphs to:

> (a) changes in voluntary load curtailment;
>
> (b) changes in involuntary load shedding using a reasonable forecast of the value of electricity to consumers.

3.3.2 Submissions

No submissions were received in relation to this proposal.

3.3.3 AER final decision

As proposed.

3.4 Competition benefits

3.4.1 Proposed amendment

The AER proposed to clarify that competition benefits may arise from load shedding or demand side response by replacing ‘generator bidding’ with ‘participant bidding’ in the relevant provision. Further, the AER sought to simplify the current definition of competition benefits in the regulatory test by transferring the details on the methodology to calculate competition benefits to the application guidelines.

The AER also proposed to amend the test to remove the current limitation which only allows for the calculation of competition benefits in relation to large asset options (more than $10 million). There is no reason why an NSP may not analyse the competition benefits of a small asset if it considers it appropriate.

To address the potential for participants to calculate competition benefits inaccurately under the current test the AER proposed to:

- amend the description of competition benefits
- continue to allow participants to be free to adopt either Dr Biggar’s approach, Frontier’s approach to calculating competition benefits or another appropriate approach as discussed in the proposed application guidelines
- clarify that where the analysis separately identifies the magnitude or quantum of any competition benefits (either as a proportion or a component of the total market benefit) the analysis must make clear the methodology used to do this and
- include a provision stating that in determining the market benefit there is to be no double-counting of competition benefits where they have already been accounted for in other elements of the market benefit.

3.4.2 Submissions

Consistent language

ETNOF submits that clause 4(d) of the proposed regulatory test should be amended to include ‘differences in transmission investment.’ rather than ‘deferral of transmission investment’. ETNOF considers this would make it more consistent with the majority of the sub-clauses which refer to ‘changes in …’ or ‘differences in …’ factors. ETNOF submits this would better accommodate comparison of options with different transmission developments (as opposed to those having the same transmission development but with different timings).

Using market impact of transmission congestion (MITC) data

The MEU suggests that the MITC data developed by the AER provides measures for assessing the cost of a constraint and that these costs should be considered in calculating competition benefits for the purposes of cost benefit analysis under the regulatory test.

3.4.3 AER final decision

Consistent language

The AER has considered ETNOF's submission and agrees that the language used in paragraph 4 of the regulatory test should be consistent. However the AER considers the drafting of the provision already allows for the comparison of different types of transmission investment though the consideration of different capital costs and operational and maintenance costs.

The AER has therefore decided to revise paragraph 4(d) to read:

> (d) changes in costs caused through:
>
> (i) differences in the timing of new plant;
>
> (ii) differences in capital costs;
>
> (iii) differences in the operational and maintenance costs; and
>
> (iv) differences in the timing of transmission investment;

Using MITC data

In response to the MEU's suggestion that the MITC data be considered in the cost benefit analysis under the regulatory test, the AER agrees that each of the three MITC measures provides useful information on transmission congestion levels and trends. However, the MITC measures have limitations in performing the role suggested by the MEU. As acknowledged by the MEU, the MITC measures are based on generators' actual bids. To the extent these bids do not represent generators' marginal costs, the MITC data is not an accurate measure of the economic cost of congestion. Therefore, the AER considers that it is inappropriate to use this data in regulatory test assessments.

3.5 Classes of costs and benefits

3.5.1 Proposed revision

Version 2 of the regulatory test states:

> In determining costs or market benefits, any cost or benefit which cannot be measured as a cost or benefit to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded.

The AER argued that the phrase 'in terms of financial transactions in the market' in this provision is unnecessary and confusing as it could be interpreted as meaning the analysis is limited to transactions in the wholesale electricity market. A market benefit analysis extends beyond the scope of the wholesale market to all producers, consumers and transporters of electricity in the NEM. The AER therefore proposed to remove this phrase from this provision.

3.5.2 Submission

ETNOF considers that given previous debate around this issue such as whether carbon emissions should be factored into the regulatory test analysis, the regulatory test must make it clear that externalities are not to be included in the analysis, and that only costs that result in a financial transaction should be included. ETNOF suggest retaining the reference to financial transactions in the wording of the regulatory test in order to address this point. ETNOF submits that removing ‘in the market’ and retaining ‘financial’ might address the AER’s concern regarding misinterpretation of the phrase ‘in the market.’

3.5.3 AER final decision

The AER has carefully considered ETNOF’s suggested redraft and accepts its proposal to have the regulatory test state:

> In determining costs or market benefits, any cost or benefit which cannot be measured as a cost or benefit to producers, distributors and consumers of electricity in terms of financial transactions should be disregarded.

The AER considers this makes it sufficiently clear that a market benefit analysis extends beyond the scope of the wholesale market to all producers, consumers and transporters of electricity in the NEM whilst excluding externalities from the analysis.

3.6 Alternative options

3.6.1 Proposed amendment

In amending the test to reflect clause 5.6.5A(c)(8) of the NER[23] the AER has included words in the test to allow alternative options to constitute a combination of other options. For example, a combination of a demand-side option and a generation option could together constitute a viable alternative option to a proposed network augmentation. The AER therefore proposes to reflect this idea in the consideration of likely alternatives through the following provision:

> In determining whether an *alternative option* is likely for the purposes of any analysis in accordance with paragraph 1(b) of this test the *Network Service Provider* must:
>
> (a) Consider all *alternative options* without bias regarding:
>
> …

[23] which states that the regulatory test must provide that alternative options considered as part of a market benefits assessment may include (without limitation) generation, demand side management, other network options, or the substitution of demand for electricity by the provision of alternative forms of energy.

(vii) whether the option or *alternative option* represents a combination of other options.

The AER considers this amendment is appropriate given the objective for a regulatory test analysis to be unbiased and facilitate the consideration of efficient solutions.

3.6.2 Submissions

Both ETNOF and Energy Response supported this revision in their submissions.

3.6.3 AER final decision

As proposed.

3.7 Projects and scenarios

3.7.1 Proposed amendment

Scenarios

The AER proposed several amendments to the test provisions dealing with scenarios.

The first is to correct an oversight and italicise 'market development scenarios' in the test to make it clear that it has a defined meaning.

The second is to make clear that a 'reasonable scenario' represents a certain state of the world. As such, all elements of a particular reasonable scenario must be mutually consistent with one another. Therefore, a given reasonable scenario must reflect, for example, a unique demand forecast, set of generation costs and market development scenario.

In this context, the third change is to simplify the provision dealing with market development scenarios to remove unnecessary repetition. The AER therefore proposed to revise the test so that that the reasonable scenarios paragraph simply states:

> Reasonable scenarios means scenarios incorporating reasonable and mutually consistent:
>
> …market development scenarios which must include, for each relevant option or alternative option:
>
> (i) all *committed projects*;
>
> (ii) *anticipated projects*, to the extent they are likely to be commissioned within the modelling period;
>
> (iii) *modelled projects*; and
>
> (iv) any other technically feasible projects identified during the consultation process.

The AER also removed 'competitively' from paragraph 4(a)(ii) of the current test. This is to address the potential that this word may imply short-run marginal cost (SRMC) should bidding be used in calculating competition benefits which is inconsistent with the above amendment to leave it to participants to choose between this approach, a realistic bidding approach or another appropriate approach.

The AER has also made amendments related to 'modelled projects' to mandate the use of least cost modelling and leave it up to participants to undertake market-driven development modelling in addition to the minimum requirement.

Sensitivity testing

The AER considers that the meaning of the paragraph 15 of version 2 of the regulatory test (which states that the calculation of *costs* and *market benefits* must encompass sensitivity testing on key input variables) may be confusing to parties seeking to apply the regulatory test. For the sake of consistency, the AER proposed to revise the test to:

- state that reasonable scenarios under the test must encompass sensitivity testing on key input variables and
- remove 'market benefits'(using all reasonable methodologies) as a key input.

Further, the AER has made revisions to:

- include estimates of the price elasticity of demand as a sensitivity as they are important to determining the impact of demand-side response options
- amend the provision dealing with ancillary services costs to make sure that they reflect the ancillary services requirements pertaining to a particular option or alternative option and
- include different anticipated projects as a sensitivity in light of changes to the treatment of anticipated projects in the definition of market development scenarios (see above).

The AER also amended paragraph 24(f) of the proposed regulatory test to state:

> … Sensitivity testing may be carried out on the following, and should be appropriate to the size and type of project:
>
> …
>
> (f) generation bidding behaviour using:
>
> (i) short run marginal cost; and
>
> (ii) approximates of realistic bidding.

The AER proposed to delete 'if measuring competition benefits' from the sub clause (f)(ii). This has been done to align the sensitivity provisions with the amendments related to the consideration of alternative options. The AER recognises that approximates of realistic bidding may be used in assessing alternative options under the reliability limb as well as the market benefits limb, and that the words ‘if measuring competition benefits’ unecessarily limits the use of realistic bidding to only cases where competition benefits are included in the analysis.

3.7.2 Submissions

No submissions were received in relation to this amendment.

3.7.3 AER final decision

As proposed.

3.8 Transitional provisions

3.8.1 Proposed amendment

Chapter 11 of the NER currently provides broad provisions for the transition between version 2 to version 3 of the test. Clause 11.7.2(b) of the NER states:

> Old clause 5.6.5A, and the regulatory test promulgated under that clause 5.6.5A, continues to apply to and in respect of, any current application and any transitional application.

Clause 11.7.1 of the NER defines current application as

> any action taken or process commenced under the Rules, which relies on or is referenced to, the regulatory test, and is not completed as at the commencement date’ (ie: 30 November 2006).

It also states that transitional application means

> any action taken or process commenced under the Rules, which relies on or is referenced to, the regulatory test and is not completed on 31 December 2007, or the date on which amendments (if any) to the regulatory test commence, whichever is the earlier.

The effect of these provisions is that version 2 of the regulatory test will continue to apply to any regulatory test analysis or related process commenced prior to the promulgation of version 3 of the test.

For clarity, the AER proposed to include more detailed transitional provisions in the test which relate to the specific processes which might already have commenced before the promulgation of version 3 of the test. The AER considered that the following transitional provisions would be consistent with, and supplement, those in the NER. These are very similar to the transitional provisions in the regulatory test version 2.

> This version of the *regulatory test* (version 3) comes into operation from the date of its promulgation, subject to the following transitional provisions which are to be read in conjunction with chapter 11 of the NER. For clarity, version 2 of the *regulatory test* continues to apply in relation to:
>
> (a) possible options for which a *distribution network service provider* has commenced consultation under clause 5.6.2(f) or an economic cost effectiveness analysis under clause 5.6.2(g) prior to the promulgation of version 3 of the *regulatory test*;

(b) a *new small network asset* for which a *transmission network service provider* has set out the matters required under clause 5.6.2A(b)(4) and (5) in an Annual Planning Report published prior to the promulgation of version 3 of the *regulatory test*;

(c) a *new small network asset* not identified in an Annual Planning Report for which a *transmission network service provider* has published a report required under clause 5.6.6A(c) of the NER prior to the promulgation of version 3 of the *regulatory test*;

(d) a *new large network asset* for which a *transmission network service provider* has published an application notice under clause 5.6.6(b) prior to the promulgation of version 3 of the *regulatory test*.

3.8.2 Submissions

EnergyAustralia submits that the transitional provisions in the test may cause confusion with those in the NER and that it would be best for the regulatory test to simply refer to the NER for transitional arrangements.

ETNOF considers that the transitional provisions proposed by the AER are more restrictive than those in the NER. ETNOF notes that preparatory work is required prior to the issue of an application notice, such as conducting a voluntary RFI processes, and that this would qualify as an ‘action or process’, as contemplated by the NER. ETNOF therefore disagrees that version 2 of the regulatory test should only continue to apply to those projects which have already issued an application notice. ETNOF recommends that the AER exclude transitional provisions in this version of the regulatory test to avoid any inadvertent conflict with the provisions already contained in the NER. Alternatively, ETNOF considers paragraph 32(d) should be amended to refer to ‘actions or processes’, consistent with the NER.

3.8.3 AER final decision

Following careful consideration of the submissions of the transitional provisions, the AER has decided to retain transitional provisions in the test which relate to the specific processes which might already have commenced before the promulgation of version 3 of the test. The AER considers that these are consistent with the NER. The AER reviewed ETNOF’s specific proposal to replace ‘application notice’ with ‘action or process commenced under the Rules’ for consistency with the NER. Whilst the AER considers that for TNSPs the first official ‘action or process’ which can be viewed as being ‘commenced under the Rules, which relies on or is referenced to, the regulatory test’ is the publication of an application notice, the AER recognises that a voluntary RFI process would be an important element of a regulatory test assessment which should be accommodated in transitional provisions.

As such the AER has decided to amend the transitional provisions to reflect the term ‘action or process’ as used in the NER, but clarify that for a new large network asset these are limited to something specifically required by the NER such as an application notice under clause 5.6.6(b). The amended provision states:

> This version of the *regulatory test* (version 3) comes into operation from the date of its promulgation, subject to the following transitional provisions which are to be read in conjunction with chapter 11 of the NER. For clarity, version 2 of the *regulatory test* continues to apply in relation to:

...

(d) a new large network asset for which a transmission network service provider has taken an action or commenced a process under the Rules, which relies on or is referenced to, the regulatory test (such as publishing an application notice under clause 5.6.6(b)) and is not completed prior to the promulgation of version 3 of the regulatory test.

The AER considers that this transitional provision is consistent with the NER.

4 Application Guidelines

4.1 Introduction

This section outlines the AER's final decision in relation to application guidelines to 'give effect to and be consistent with clause 5.6.5A and provide guidance on the operation and application of the regulatory test.'

These application guidelines are published at the same time as the regulatory test version 3. While the application guidelines are to be used for guidance, they are not binding.

4.2 AER considerations

The AER has prepared, with the assistance of Frontier Economics, application guidelines to aid in the consistent application of the regulatory test and clarify technical concepts and provisions.

It should be noted that these guidelines are to be **read in conjunction** with the regulatory test and are not a substitute for the test. Nor are they meant to be a step by step manual on how to conduct a regulatory test analysis. The AER's intention is that the guidelines elaborate on, and clarify ideas and concepts in the test whilst avoiding repeating the test itself.

4.3 Time limit on options in application guidelines

4.3.1 Proposed guideline

The proposed application guidelines stated that all the projects to be combined to form an option should have anticipated commissioning dates within a reasonable timeframe of the regulatory test assessment, such as within 5-10 years.

4.3.2 Submissions

EnergyAustralia submits that the suggested timeframe for options contradicts NSP annual planning requirements. EnergyAustralia considers that by stating that all the projects to be combined to form an option should have anticipated commissioning dates within a reasonable timeframe of the regulatory test assessment, such as within 5-10 years, the guideline is inconsistent with the minimum 5 year planning horizon for distribution investment and 10 year horizon for transmission investments set out in the NER annual planning requirements. EnergyAustralia recommends removal of this time limit as it will differ depending on the circumstances of the proposed investment.

4.3.3 AER final decision

The AER has carefully considered EnergyAustralia's submission and clarifies that the 5-10 timeframe was for guidance only and was intended to protect the regulatory test analysis from including uncertain projects as part of a likely option. However, the AER recognises that it could potentially cause confusion with annual planning requirements. The AER has therefore decided to remove the suggested 5-10 year timeframe but left 'within a reasonable timeframe of the regulatory test assessment' to act as a limit on the scope of future investments to be included in the analysis.

4.4 Other issues

4.4.1 Submissions

ETNOF and EnergyAustralia submit that the application guidelines do not distinguish sufficiently between the reliability limb of the test and the market benefit limb. For example ETNOF submits that the reference to any negative impacts of an option on the NEM being taken into account in the calculation of market benefit in section 3(c) is only true under the market benefit limb of the regulatory test and that section 7 does not sufficiently differentiate between the notion of alternative options between the two limbs. EnergyAustralia suggests that the guidelines be separated into a market benefits section and a reliability limb section to avoid confusion

ETNOF also suggests removal of the words 'the intent appears to be' in section 2.4 as it considers the guidelines should simply confirm that: 'an option intended to meet a reliability requirement is not precluded from being assessed as a reliability project under paragraph (1)(a) of the regulatory test if the option also provides market benefits.'

4.4.2 AER final decision

The AER has carefully considered submissions to differentiate more between the two limbs of the test in the application guidelines and perhaps go as far as dividing the guidelines into two sections. The AER considers the guidelines are currently effectively set out and follow the structure of the regulatory test. The AER has therefore decided against restructuring the guidelines to reflect the two limbs.

The AER has decided to implement ETNOF's suggestion to amend section 2.4 to make it clear that a project may be assessed under the reliability limb even if it provides some market benefits.

5 Conclusion

The AER promulgates this *regulatory test version 3* at Appendix A in accordance with clause 5.6.5A of the NER. The AER also issues the *regulatory test application guidelines (attached)* in accordance with the NER.

For comparative purposes, a table comparing the previous version of the regulatory test with this version 3 is at Appendix B.

Appendix A: Regulatory Test, version 3

Introduction

The Australian Energy Regulator (AER) publishes this *regulatory test* in accordance with clause 5.6.5A of the National Electricity Rules (the NER). An accompanying set of regulatory test application guidelines are published in accordance with clause 5.6.5A(d).

Clause 5.6.5A(b) of the NER states that the purpose of the regulatory test is to identify new network investments or non-network alternative options that:

(a) maximise the net economic benefit to all those who produce, consume and transport electricity in the market; or

(b) in the event the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments, minimise the present value of the costs of meeting those requirements.

As required by the NER this test is to be applied in relation to new network investments estimated to require a total capitalised expenditure in excess of $1 million. The regulatory test only applies to network augmentations and does not apply to the replacement of assets.

Transmission network service providers (TNSPs) are required to apply the test in accordance with clause 5.6.6 of the NER. Distribution network service providers (DNSPs) must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test under clause 5.6.2(g) of the NER. Under those clauses, TNSPs and DNSPs are also required to publicly consult on applications to establish new large network investments, that is, investments estimated to require total capitalised expenditure in excess of $10 million.[*]

Proposed new network investments or non-network alternative options may satisfy the test via one of its two limbs- the 'reliability' limb or the 'market benefits' limb.

Reliability limb

The reliability limb relates to clause 5.6.5A(b)(2) of the NER set out above. It is to be applied to any proposed new network investment or non-network alternative option in the event that the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 or in *applicable regulatory instruments*.

While the reliability limb of the test applies to both transmission and distribution network augmentations, in the case of transmission, this limb directly relates to the following definition of *reliability augmentation* in chapter 10 of the NER. This states that a *reliability augmentation* is:

> A *transmission* network *augmentation* that is necessitated principally by inability to meet the minimum network performance requirements set out in schedule 5.1 or in relevant legislation, regulations or any statutory instrument of a *participating jurisdiction*.

Market benefits limb

The market benefits limb is to be used for any new network investment that is not assessed under the reliability limb. This limb relates to clause 5.6.5A(b)(1) of the NER set out above and is based on a cost-benefit analysis (as required by clause 5.6.5A(c)(1)).

The level of analysis undertaken in relation to the market benefits limb must be proportionate to the scale and size of the proposed new network investment.

In accordance with clause 5.6.5A(c)(4) of the NER, this regulatory test contains request for information requirements for any proposed new large transmission network asset assessed under the market benefits limb.

*Where this value differs from that in the NER, the NER value will apply.

The regulatory test

(1) An option satisfies the *regulatory test* if:

(a) in the event the option is necessitated principally by inability to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments - the option minimises the *costs* of meeting those requirements, compared with *alternative option/s* in a majority of *reasonable scenarios*;

(b) in all other cases - the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the *market benefit* less *costs.*

Costs and benefits

Costs

(2) *Costs* means the present value of the direct costs of an option (or an *alternative option*) including:

(a) costs incurred in constructing or providing the option;

(b) operating and maintenance costs over the operating life of the option; and

(c) the cost of complying with laws, regulations and applicable administrative requirements in relation to the option.

Benefits

(3) *Market benefit* means the present value of the total benefit of an option (or an *alternative option*) to all those who produce, distribute and consume electricity in the National Electricity Market (NEM). That is, the change in consumers' plus producers' surplus or another measure that can be demonstrated to produce an equivalent ranking of options in a majority of *reasonable scenarios*. For clarity, *market benefit* does not include the transfer of surplus between consumers and producers, nor does it include the *costs* defined in paragraph 2.

(4) In determining the *market benefit*, the analysis may include the present value of the following benefits:

(a) changes in fuel consumption arising through different generation dispatch;

(b) changes in voluntary load curtailment;

(c) changes in involuntary load shedding using a reasonable forecast of the value of electricity to consumers;

(d) changes in costs caused through:

(i) differences in the timing of new plant;

(ii) differences in capital costs;

(iii) differences in the operational and maintenance costs; and

(iv) differences in the timing of transmission investments;

(e) changes in transmission losses;

(f) changes in ancillary services costs;

(g) *competition benefits* being net changes in *market benefit* arising from the impact of the option on participant bidding behaviour; and

(h) other benefits that are determined to be relevant to the case concerned.

(5) Where the analysis separately identifies the magnitude or quantum of any *competition benefits* (either as a proportion or a component of the total *market benefit*) the analysis must make clear the methodology used to estimate it.

(6) The *market benefit* of an option will only include *competition benefits* where the *network service provider* responsible for undertaking the analysis of the option determines that it is appropriate, in all the circumstances, to take *competition benefits* into account.

(7) In determining the *market benefit*, the analysis must not double-count *competition benefits* where they have already been accounted for in other elements of the *market benefit.*

Disclosing costs and benefits

(8) Any relevant information which may have a material impact on the determination of *costs* or *market benefits* which comes to light at any time before an assessment is finalised must be considered and made available to interested parties.

(9) Detailed calculations of how *costs* and *market benefits* are determined must be included in the *regulatory test* analysis and made available to interested parties.

Classes of possible costs and benefits

(10) Any cost or benefit which cannot be measured as a cost or benefit to producers, distributors and consumers of electricity may not be included in any analysis proposed in accordance with this test. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the cost allocation principles in clause 6A.19.2 of the NER in the case of transmission, or consistent with the relevant jurisdictional guideline in the case of distribution.

(11) In determining the *costs* or *market benefits*, it should be considered whether the proposed option will enable:

(a) a *transmission network service provider* to provide both prescribed and other services; or

(b) a *distribution network service provider* to provide both prescribed distribution services and other services.

If it does, the *costs* and *market benefits* associated with the other services should be disregarded. The allocation of costs between prescribed and other services must be consistent with the cost allocation principles in clause 6A.19.2 of the NER. The allocation of costs between prescribed distribution services and other services must be consistent with the relevant jurisdictional guideline.

Method permitted for estimating the magnitude of the different classes of costs and benefits

(12) In estimating the magnitude of costs and benefits, a pool dispatch modelling methodology, or any other applicable methodology, should be used. If pool dispatch modelling methodology is used, it must incorporate:

(a) a realistic treatment of plant characteristics, including for example minimum generation levels and variable operation costs; and

(b) a realistic treatment of the network constraints and losses.

Appropriate method for determining the discount rate to be applied

(13) The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used should be consistent with the cash flows being discounted.

Alternative options

(14) An *alternative option* may be, without limitation, a generation option, demand side management/response option, network option, the substitution of electricity by the provision of alternative forms of energy, or a combination of these.

(15) For an option proposed in accordance with paragraph 1(a) of this test *alternative option* means:

(a) a genuine alternative to the option being assessed, in that it:

(i) has a clearly identifiable proponent/s; and

(ii) meets the reliability requirements referred to in paragraph 1(a); and

(b) a practicable alternative to the option being assessed in that it is technically feasible.

(16) For an option proposed in accordance with paragraph 1(b) of this test *alternative option* means:

(a) a genuine alternative to the option being assessed, in that it:

(i) delivers similar outcomes to those delivered by the option being assessed; and

(ii) would become operational in a similar timeframe to the option being assessed; and

(b) a practicable alternative to the option being assessed in that it is technically feasible.

(17) In determining whether an *alternative option* is likely for the purposes of any analysis in accordance with paragraph 1(b) of this test the *network service provider* must:

(a) consider all *alternative options* without bias regarding:

(i) energy source;

(ii) technology;

(iii) ownership;

(iv) the extent to which the proposed network asset or non-network alternative enables intra-regional or intra-regional trading of electricity;

(v) whether it is a network or non-network alternative;

(vi) whether the *alternative option* is intended to be regulated; and

(vii) whether the option or *alternative option* represents a combination of other options.

(b) consider whether the *alternative option* has a genuine proponent. However, the absence of such a proponent will not in itself exclude a project from being a likely *alternative option* for the purposes of the *regulatory test*.

(c) consider whether the *alternative option* is commercially feasible, which is to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide this *alternative option*.

(d) where the proposed asset is a *new large transmission network asset,*

(i) consider any *alternative options* proposed in the request for information process required by this test. However, there should be no presumption that a proposed *alternative option* is likely and

(ii) include in any *regulatory test* analysis completed in relation to the proposed *new large transmission network asset*:

(I) a summary of any *alternative options* proposed in the relevant request for information process and

(II) detailed reasons as to why an *alternative option* was found to be likely or unlikely.

(18) Where there is more than one likely *alternative option* to the new *network* investment, and no single *alternative option* is significantly more likely to occur than the other, then the *market benefits* analysis required in accordance with paragraph (1)(b) of this test must be undertaken in relation to each such likely *alternative option*.

Projects and scenarios

(19) *Reasonable scenarios* means scenarios incorporating reasonable and mutually consistent:

(a) forecasts of:

(i) electricity demand (modified where appropriate to take into account demand-side options, economic growth, weather patterns and price elasticity);

(ii) the efficient operating costs of supplying energy to meet forecast demand from existing, *committed, anticipated* and *modelled proje*cts including demand side and generation projects;

(iii) the avoidable costs of *committed*, *anticipated* and *modelled projects* including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred;

(iv) the cost of providing sufficient ancillary services to meet the forecast demand to support the relevant option or *alternative option*; and

(v) the capital and operating costs of other regulated network and market network service projects that are augmentations consistent with the forecast demand and generation scenarios;

(b) *market development scenarios*, which must include, for each relevant option or *alternative option* :

(i) all *committed projects*;

(ii) *anticipated projects*, to the extent they are likely to be commissioned within the modelling period;

(iii) *modelled projects*; and

(iv) any other technically feasible projects identified during the consultation process; and

(c) sensitivity testing.

(20) *Committed project* means a project which satisfies all the following criteria:

(a) the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;

(b) construction of the proposal must either have commenced or a firm commencement date must be set;

(c) the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for construction of the proposed development;

(d) contracts for supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and

(e) the financing arrangements for the proposal, including any debt plans, must have been finalised and contracts executed.

(21) *Anticipated project* means a project which:

(a) does not meet each of the criteria in paragraph 20; and

(b) is in the process of meeting one or more of the criterion in paragraph 20.

(22) *Modelled project* means a hypothetical project derived from market development modelling in the presence or absence (as applicable) of the relevant option or *alternative option*. Market development modelling must be undertaken on a 'least-cost' basis and, where appropriate, may be undertaken on a 'market-driven' basis, where:

(a) least-cost market development modelling derives *modelled projects* on the basis of a least-cost planning approach akin to conventional central planning. The *modelled projects* derived from such an approach would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceed the costs.

(b) market-driven market development modelling derives *modelled projects* on the same basis as that of a private developer. The *modelled projects* derived from such an approach would be those where the net present value of generation revenues (from the spot market or contracts) exceeds the net present value of generation costs. The forecasts of price trends should reflect realistic bidding behaviour, with power flows to be those most likely to occur under actual systems and market outcomes.

Sensitivity testing

(23) *Reasonable scenarios* under this test must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on the following, and should be appropriate to the size and type of project:

(a) testing reasonable forecasts of the value of electricity to consumers.

(b) price elasticity of demand.

(c) capital and operating costs of *alternative options*.

(d) discount rate (the lower boundary should be the regulated cost of capital).

(e) market demand.

(f) generation bidding behaviour using:

(i) short run marginal cost; and

(ii) approximates of realistic bidding.

(g) commissioning dates of:

(i) the option being assessed;

(ii) *alternative options*;

(iii) *committed projects*; and

(iv) *anticipated projects*

(h) inclusion or exclusion of particular *anticipated projects* based on their degree of likelihood of being commissioned within the modelling period;

(i) *modelled projects* based on a market-driven market development modelling approach

(j) market based regulatory instruments that may be used to address greenhouse and environmental issues and

(k) other sensitivity testing determined to be relevant and material to the case concerned.

Request for information

(24) For the purposes of any analysis undertaken in relation to paragraph (1)(b) of this test, a *transmission network service provider* must publish a request for information notice for a potential or proposed *new large transmission network asset*.

(25) The request for information notice must request information as to the identity and detail of alternative options to the potential or proposed *new large transmission network asset*.

(26) The *transmission network service provider* must include the following information in the request for information notice:

(a) the details of any potential or proposed *new large transmission network asset* including:

(i) all of the relevant technical details, including asset type and project configuration;

(ii) the proposed construction timetable;

(iii) the commissioning date; and

(iv) all known expected *costs* and the likely sources of *costs* and *market benefits* associated with the proposed asset;

(b) the reasons for the potential *new large transmission network asset,* including how the potential asset satisfies these reasons and, where applicable, any network limitations, reliability requirements or specific planning criteria;

(c) known existing and planned infrastructure in the geographic region, including relevant transmission, distribution and generation assets;

(d) load forecasts in the geographic region for the next ten years including peak demand and load profiles;

(e) any specific project requirements that an *alternative option* must fulfil including any technical or other limitations such as:

(i) speed of demand side or generation response;

(ii) size, type and location of load(s) to be reduced, shifted, substituted or interrupted; and

(iii) size, type and location of generation to be installed or utilised; and

(f) a description of the process for assessing *alternative options* including evaluation criteria.

(27) Before an application notice in relation to the proposed *new large transmission network asset* is published, the *transmission network service provider* must:

(a) publish the request for information notice on its website and

(b) provide the request for information notice to NEMMCO for publication on the NEMMCO website.

(28) The request for information notice must specify a due date for submissions which must be a minimum of 8 weeks after the date the request for information notice is published on NEMMCO's website.

(29) Any person may make a written submission to the *transmission network service provider* in response to the request for information notice.

Transitional provisions

(30) This version of the *regulatory test* (version 3) comes into operation from the date of its promulgation, subject to the following transitional provisions which are to be read in conjunction with chapter 11 of the NER.

For clarity, version 2 of the *regulatory test* continues to apply in relation to:

(a) possible options for which a *distribution network service provider* has commenced consultation under clause 5.6.2(f) or an economic cost effectiveness analysis under clause 5.6.2(g) prior to the promulgation of version 3 of the *regulatory test*;

(b) a *new small network asset* for which a *transmission network service provider* has set out the matters required under clause 5.6.2A(b)(4) and (5) in an Annual Planning Report published prior to the promulgation of version 3 of the *regulatory test*;

(c) a *new small network asset* not identified in an Annual Planning Report for which a *transmission network service provider* has published a report required under clause 5.6.6A(c) of the NER prior to the promulgation of version 3 of the *regulatory test*;

(d) a *new large network asset* for which a *transmission network service provider* has taken an action or commenced a process under the Rules, which relies on or is referenced to, the *regulatory test* (such as publishing an application notice under clause 5.6.6(b)) and is not completed prior to the promulgation of version 3 of the *regulatory test.*

Appendix B: Comparison of version 2 and version 3

<table>
<tr><th><u>Proposed Version 3</u></th><th><u>Version 2</u></th></tr>
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Introduction

The Australian Energy Regulator (AER) publishes this *regulatory test* in accordance with clause 5.6.5A of the National Electricity Rules (the NER). An accompanying set of regulatory test application guidelines are published in accordance with clause 5.6.5A(d).

Clause 5.6.5A(b) of the NER states that the purpose of the regulatory test is to identify new network investments or non-network alternative options that:

(a) maximise the net economic benefit to all those who produce, consume and transport electricity in the market; or

(b) in the event the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments, minimise the present value of the costs of meeting those requirements.

As required by the NER this test is to be applied in relation to new network investments estimated to require a total capitalised expenditure in excess of $1 million. The regulatory test only applies to network augmentations and does not apply to the replacement of assets.

Transmission network service providers (TNSPs) are required to apply the test in accordance with clause 5.6.6 of the Rules. Distribution network service providers (DNSPs) must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test under clause 5.6.2(g) of the NER. Under those clauses, TNSPs and DNSPs are also required to publicly consult on applications to establish new large network investments, that is, investments estimated to require total capitalised expenditure in excess of $10 million.*

Proposed new network investments or non-network alternative options may satisfy the test via one of its two limbs- the ‘reliability’ limb or the ‘market benefits’ limb.

Reliability limb

The reliability limb relates to clause 5.6.5A(b)(2) of the NER set out above. It is to be applied to any proposed new network investment or non-network alternative option in the event that the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 or in *applicable regulatory instruments*.

While the reliability limb of the test applies to both transmission and distribution network augmentations, in the case of transmission, this limb directly relates to the following definition of *reliability augmentation* in chapter 10 of the NER. This states that a *reliability augmentation* is:

> A *transmission* network *augmentation* that is necessitated principally by inability to meet the minimum network performance requirements set out in schedule 5.1 or in relevant legislation,

</td><td>

Preamble

The Australian Competition and Consumer Commission promulgates this *regulatory test* in accordance with clause 5.6.5A of the National Electricity Code (the Code).

In this test “option” includes, but is not limited to, an *augmentation, new large network asset* and *new small network asset.*

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regulations or any statutory instrument of a *participating jurisdiction*. *Market benefits limb* The market benefits limb is to be used for any new network investment that is not assessed under the reliability limb. This limb relates to clause 5.6.5A(b)(1) of the NER set out above and is based on a cost-benefit analysis (as required by clause 5.6.5A(c)(1)). The level of analysis undertaken in relation to the market benefits limb must be proportionate to the scale and size of the proposed new network investment. In accordance with clause 5.6.5A(c)(4) of the NER, this regulatory test contains request for information requirements for any proposed new large transmission network asset assessed under the market benefits limb. *where this value differs from that in the NER, the NER value applies.	
The regulatory test (1) An option satisfies the *regulatory test* if: (a) in the event the option is necessitated principally by to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments - the option minimises the *costs* of meeting those requirements, compared with *alternative option/s* in a majority of *reasonable scenarios*; (b) in all other cases - the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the *market benefit* less *costs.*	***regulatory test*** (1) An option satisfies the *regulatory test* if: (a) in the event the option is necessitated solely by the inability to meet the minimum network performance requirements set out in schedule 5.1 of the Code or in relevant legislation, regulations or any statutory instrument of a participating jurisdiction - the option minimises the present value of *costs*, compared with a number of *alternative options* in a majority of *reasonable scenarios*; (b) in all other cases - the option maximises the expected net present value of the *market benefit* (or in other words the present value of the *market benefit* less the present value of *costs*) compared with a number of *alternative options* and timings, in a majority of *reasonable scenarios*.
Costs and Benefits ***Costs*** (2) *Costs* means the present value of the direct costs of an option (or an *alternative option*) including: (a) costs incurred in constructing or providing the option; (b) operating and maintenance costs over the operating life of the option; and (c) the cost of complying with laws, regulations and applicable administrative requirements in relation to the option.	For the purposes of this test: (2) Costs means the total cost of an option (or an alternative option) to all those who produce, distribute or consume electricity in the National Electricity Market. In determining the costs, the analysis may include, but need not be limited to, the following: (a) costs incurred in constructing or providing the option; (b) operating and maintenance costs over the operating life of the option; (c) the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution (including greenhouse gas abatement). An environmental tax should be treated as part of a

Benefits

(3) *Market benefit* means the present value of the total benefit of an option (or an *alternative option*) to all those who produce, distribute and consume electricity in the National Electricity Market (NEM). That is, the change in consumers' plus producers' surplus or another measure that can be demonstrated to produce an equivalent ranking of options in a majority of *reasonable scenarios*. For clarity, *market benefit* does not include the transfer of surplus between consumers and producers, nor does it include the *costs* defined in paragraph 2.

(4) In determining the *market benefit*, the analysis may include the present value of the following benefits:

(a) changes in fuel consumption arising through different generation dispatch;

(b) changes in voluntary load curtailment;

(c) changes in involuntary load shedding using a reasonable forecast of the value of electricity to consumers;

(d) changes in costs caused through:

(i) differences in the timing of new plant;

(ii) differences in capital costs;

(iii) differences in the operational and maintenance costs; and

(iv) differences in the timing of transmission investments;

(e) changes in transmission losses;

(f) changes in ancillary services costs;

(g) *competition benefits* being net changes in *market benefit* arising from the impact of the option on participant bidding behaviour; and

(h) other benefits that are determined to be relevant to the case concerned.

(5) Where the analysis separately identifies the magnitude or quantum of any *competition benefits* (either as a proportion or a component of the total *market benefit*) the analysis must make clear the methodology used to estimate it.

(6) The *market benefit* of an option will only include *competition benefits* where the *network service provider* responsible for undertaking the analysis of the option determines that it is appropriate, in all the circumstances, to take *competition benefits* into account.

(7) In determining the *market benefit*, the analysis must not double-count *competition benefits* where they have already been accounted for in other elements of the *market benefit.*

project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost.

(d) other costs that are determined to be relevant to the case concerned.

(5) *Market benefit* means the total benefits of an option (or an alternative option) to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the change in consumers' plus producers' surplus or another measure that can be demonstrated to produce an equivalent ranking of options in a majority of reasonable scenarios. For clarity, market benefit does not include the transfer of surplus between consumers and producers.

In determining the market benefit, the analysis may include, but need not be limited to the following benefits:

(a) changes in fuel consumption arising through different generation dispatch;

(b) changes in voluntary load curtailment caused through reduction in demand-side curtailment;

(c) changes in involuntary load shedding caused through savings in reduction in lost load, using a reasonable forecast of the value of electricity to consumers, or deferral of reliability entry plant;

(d) changes in costs caused through:

(i) deferral of market entry plant. This must be excluded if reliability benefits are determined using deferral of reliability entry plant;

(ii) differences in capital costs;

(iii) differences in the operational and maintenance costs; and

(iv) deferral of transmission investments;

(e) changes in transmission losses;

(f) changes in ancillary services;

(g) *competition benefits*; and

(h) other benefits that are determined to be relevant to the case concerned.

(6) Competition benefits means the change in benefit between the scenario where, after implementation of the option:

(a) generator bidding is assumed to be the same as it was before the option was implemented; and

(b) generator bidding reflects any market power after the implementation of the option.

Disclosing costs and benefits

(8) Any relevant information which may have a material impact on the determination of *costs* or *market benefits* which comes to light at any time before an assessment is finalised must be considered and made available to interested parties.

(9) Detailed calculations of how *costs* and *market benefits* are determined must be included in the *regulatory test* analysis and made available to interested parties.

Classes of possible costs and benefits

(10) Any cost or benefit which cannot be measured as a cost or benefit to producers, distributors and consumers of electricity may not be included in any analysis proposed in accordance with this test. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the cost allocation principles in clause 6A.19.2 of the NER in the case of transmission, or consistent with the relevant jurisdictional guidelines in the case of distribution.

(11) In determining the *costs* or *market benefits*, it should be considered whether the proposed option will enable:

(a) a *transmission network service provider* to provide both prescribed and other services; or

(b) a *distribution network service provider* to provide both prescribed distribution services and other services.

If it does, the *costs* and *market benefits* associated with the other services should be disregarded. The allocation of costs between prescribed and other services must be consistent with the cost allocation principles in clause 6A.19.2 of the NER. The allocation of costs between prescribed distribution services and other services must be consistent with the relevant jurisdictional guideline.

Method permitted for estimating the magnitude of the different classes of costs and benefits

(12) In estimating the magnitude of costs and benefits, a pool dispatch modelling methodology, or any other applicable methodology, should be used. If pool dispatch modelling methodology is used, it must incorporate:

(a) a realistic treatment of plant characteristics, including for example minimum generation levels and variable operation costs; and

(b) a realistic treatment of the network constraints and losses.

Appropriate method for determining the discount rate to be applied

(13) The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used

or another reasonable measure that can be demonstrated to produce an equivalent change in benefit.

(7) The market benefit of an option will only include competition benefits where:

(a) the option is a new large network asset or a new large distribution network asset; and

(b) the *Network Service Provider* responsible for undertaking the analysis of the option determines that it is appropriate, in all the circumstances, to take competition benefits into account in assessing the market benefit of the option.

(16) Any relevant information which may have a material impact on the determination of costs or market benefits which comes to light at any time before an assessment is finalised must be considered and made available to interested parties.

(8) In determining costs or market benefits, any cost or benefit which cannot be measured as a cost or benefit to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the Transmission Ring-Fencing Guidelines and/or Distribution Ring-Fencing Guidelines (as appropriate). Only direct costs and benefits, not including wealth transfers, (associated with a partial equilibrium analysis) should be included and any additional indirect costs or benefits (associated with a general equilibrium analysis) should be excluded from the assessment.

(9) In determining the costs or market benefits, it should be considered whether the proposed augmentation will enable:

(a) a Transmission Network Service Provider to provide both prescribed and other services; or

(b) a Distribution Network Service Provider to provide both prescribed distribution services and other services

If it does, the costs and market benefits associated with the other services should be disregarded. The allocation of costs between prescribed and other services must be consistent with the Transmission Ring-Fencing Guidelines. The allocation of costs between prescribed distribution services and other services must be consistent with the relevant Distribution Ring-Fencing Guidelines.

(10) The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used should be consistent with the cash flows being discounted.

should be consistent with the cash flows being discounted.	
Alternative options (14) An *alternative option* may be, without limitation, a generation option, demand side management/response option, network option, the substitution of electricity by the provision of alternative forms of energy, or a combination of these. (15) For an option proposed in accordance with paragraph 1(a) of this test *alternative option* means: (a) a genuine alternative to the option being assessed, in that it: (i) has a clearly identifiable proponent/s; and (ii) meets the reliability requirements referred to in paragraph 1(a); and (b) a practicable alternative to the option being assessed in that it is technically feasible. (16) For an option proposed in accordance with paragraph 1(b) of this test *alternative option* means: (a) a genuine alternative to the option being assessed, in that it: (i) delivers similar outcomes to those delivered by the option being assessed; and (ii) would become operational in a similar timeframe to the option being assessed; and (b) a practicable alternative to the option being assessed in that it is technically feasible. (17) In determining whether an *alternative option* is likely for the purposes of any analysis in accordance with paragraph 1(b) of this test the *network service provider* must: (a) consider all *alternative options* without bias regarding: (i) energy source; (ii) technology; (iii) ownership; (iv) the extent to which the proposed network asset or non-network alternative enables intra-regional or intra-regional trading of electricity; (v) whether it is a network or non-network alternative; (vi) whether the *alternative option* is intended to be regulated; and	(3) *Alternative options* means: (a) For an option proposed in accordance with paragraph 1(a) of this test: (i) a genuine alternative to the option being assessed, in that it: (A) has a clearly identifiable proponent; and (B) meets the requirements referred to in paragraph 1(a); (ii) a practicable alternative to the option being assessed in that it is technically feasible. (b) For an option proposed in accordance with paragraph 1(b) of this test: (i) a genuine alternative to the option being assessed, in that it: (A) delivers similar outcomes to those delivered by the option being assessed; and (B) becomes operational in a similar timeframe to the option being assessed; (ii) a practicable alternative to the option being assessed in that it is: (A) technically feasible; and (B) commercially feasible, which is to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide the *alternative option*. The existence of a genuine proponent for the *alternative option* should be taken into account when determining practicability, however, absence of such a proponent will not exclude a project from being an *alternative option* for the purposes of the regulatory test.

(vii) whether the option or *alternative option* represents a combination of other options. (b) consider whether the *alternative option* has a genuine proponent. However, the absence of such a proponent will not in itself exclude a project from being a likely *alternative option* for the purposes of the *regulatory test*. (c) consider whether the *alternative option* is commercially feasible, which is to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide this *alternative option*. (d) where the proposed asset is a *new large transmission network asset*, (i) consider any *alternative options* proposed in the request for information process required by this test. However, there should be no presumption that a proposed *alternative option* is likely and (ii) include in any *regulatory test* analysis completed in relation to the proposed *new large transmission network asset*: (I) a summary of any *alternative options* proposed in the relevant request for information process and (II) detailed reasons as to why an *alternative option* was found to be likely or unlikely. (18) Where there is more than one likely *alternative option* to the new *network* investment, and no single *alternative option* is significantly more likely to occur than the other, then the *market benefits* analysis required in accordance with paragraph (1)(b) of this test must be undertaken in relation to each such likely *alternative option*.	

Projects and Scenarios	
(19) *Reasonable scenarios* means scenarios incorporating reasonable and mutually consistent: (a) forecasts of: (i) electricity demand (modified where appropriate to take into account demand-side options, economic growth, weather patterns and price elasticity); (ii) the efficient operating costs of supplying energy to meet forecast demand from existing, *committed, anticipated* and *modelled proje*cts including demand side and generation projects; (iii) the avoidable costs of *committed, anticipated* and *modelled projects* including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred; (iv) the cost of providing sufficient ancillary services to meet the forecast demand to support the relevant option or *alternative option*; and (v) the capital and operating costs of other regulated network and market network service projects that are augmentations consistent with the forecast demand and generation scenarios; (b) *market development scenarios*, which must include, for each relevant option or *alternative option* : (i) all *committed projects*; (ii) *anticipated projects*, to the extent they are likely to be commissioned within the modelling period; (iii) *modelled projects*; and (iv) any other technically feasible projects identified during the consultation process; and (c) sensitivity testing.	(4) Reasonable scenarios means scenarios incorporating: (a) reasonable forecasts of: (i) electricity demand (modified where appropriate to take into account demand-side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity); (ii) the efficient operating costs of competitively supplying energy to meet forecast demand from existing, committed, anticipated and modelled projects including demand side and generation projects; (iii) the avoidable costs of committed, anticipated and modelled projects including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred; (iv) the cost of providing sufficient ancillary services to meet the forecast demand; and (v) the capital and operating costs of other regulated network and market network service projects that are augmentations consistent with the forecast demand and generation scenarios (b) scenarios defined as market development scenarios; and (c) sensitivity testing. (11) The analysis must include modelling a range of reasonable *market development scenarios*, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project commissioning dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative construction timetables as nominated by the proponent providing that relevant reliability standards would be met. *Market development scenarios* must include: (a) *committed projects*; (b) *anticipated projects*; (c) *modelled projects*; and (d) any other technically feasible projects identified during the consultation process.

(20) *Committed project* means a project which satisfies all the following criteria:	(12) *Committed project* means a project which satisfies all the following criteria:
(a) the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;	(a) the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;
(b) construction of the proposal must either have commenced or a firm commencement date must be set;	(b) construction of the proposal must either have commenced or a firm commencement date must be set;
(c) the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for construction of the proposed development;	(c) the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for construction of the proposed development;
(d) contracts for supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and	(d) contracts for supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and
(e) the financing arrangements for the proposal, including any debt plans, must have been finalised and contracts executed.	(e) the financing arrangements for the proposal, including any debt plans, must have been conducted and contracts executed.
(21) *Anticipated project* means a project which:	(13) *Anticipated project* means a project which:
(a) does not meet each of the criteria in paragraph 20; and	(a) does not meet each of the criteria in note 12; and
(b) is in the process of meeting one or more of the criterion in paragraph 20.	(b) is in the process of meeting one or more of the criterion in note 12.
(22) *Modelled project* means a hypothetical project derived from market development modelling in the presence or absence (as applicable) of the relevant option or *alternative option*. Market development modelling must be undertaken on a 'least-cost' basis and, where appropriate, may be undertaken on a 'market-driven' basis, where:	(14) *Modelled projects* means a project modelled using either 'least-cost market development' modelling or 'market-driven market development' modelling:
(a) least-cost market development modelling derives *modelled projects* on the basis of a least-cost planning approach akin to conventional central planning. The *modelled projects* derived from such an approach would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceed the costs.	(a) Least-cost market development modelling means modelling projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs.
(b) market-driven market development modelling derives *modelled projects* on the same basis as that of a private developer. The *modelled projects* derived from such an approach would be those where the net present value of generation revenues (from the spot market or contracts) exceeds the net present value of generation costs. The forecasts of price trends should reflect realistic bidding behaviour, with power flows to be those most likely to occur under actual systems and market outcomes.	(b) Market-driven market development modelling means modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price trends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate non-competitive bidding or imperfect competition, with power flows to be those most likely to occur under actual systems and market outcomes.

Sensitivity testing

(23) *Reasonable scenarios* under this test must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on the following, and should be appropriate to the size and type of project:

(a) testing reasonable forecasts of the value of electricity to consumers.

(b) price elasticity of demand.

(c) capital and operating costs of *alternative options*.

(d) discount rate (the lower boundary should be the regulated cost of capital).

(e) market demand.

(f) generation bidding behaviour using:

(i) short run marginal cost; and

(ii) approximates of realistic bidding.

(g) commissioning dates of:

(i) the option being assessed;

(ii) *alternative options*;

(iii) *committed projects*; and

(iv) *anticipated projects*

(h) inclusion or exclusion of particular *anticipated projects* based on their degree of likelihood of being commissioned within the modelling period;

(i) *modelled projects* based on a market-driven market development modelling approach

(j) market based regulatory instruments that may be used to address greenhouse and environmental issues and

(k) other sensitivity testing determined to be relevant and material to the case concerned.

(15) The calculation of the *costs* or *market benefits* must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on, but not limited to, the following, and should be appropriate to the size and type of project:

(a) *Market benefits*:

(i) Using all reasonable methodologies; and

(ii) Testing reasonable forecasts of the value of electricity to consumers.

(b) Capital and operating costs of *alternative options*.

(c) Discount rate (the lower boundary should be the regulated cost of capital).

(d) Market demand.

(e) Generation bidding behaviour using:

(i) SRMC; and

(ii) Approximates of realistic bidding if measuring competition benefits.

(f) Commissioning dates of:

(i) Alternative projects;

(ii) Committed projects;

(iii) Anticipated projects; and

(iv) Modelled projects.

(g) Market based regulatory instruments that may be used to address greenhouse and environmental issues.

(h) Other sensitivity testing determined to be relevant and material to the case concerned.

Request for information (24) For the purposes of any analysis undertaken in relation to paragraph (1)(b) of this test, a *transmission network service provider* must publish a request for information notice for a potential or proposed *new large transmission network asset*. (25) The request for information notice must request information as to the identity and detail of alternative options to the potential or proposed *new large transmission network asset*. (26) The *transmission network service provider* must include the following information in the request for information notice: (a) the details of any potential or proposed *new large transmission network asset* including: (i) all of the relevant technical details, including asset type and project configuration; (ii) the proposed construction timetable; (iii) the commissioning date; and (iv) all known expected *costs* and the likely sources of *costs* and *market benefits* associated with the proposed asset; (b) the reasons for the potential *new large transmission network asset,* including how the potential asset satisfies these reasons and, where applicable, any network limitations, reliability requirements or specific planning criteria; (c) known existing and planned infrastructure in the geographic region, including relevant transmission, distribution and generation assets; (d) load forecasts in the geographic region for the next ten years including peak demand and load profiles; (e) any specific project requirements that an *alternative option* must fulfil including any technical or other limitations such as: (i) speed of demand side or generation response; (ii) size, type and location of load(s) to be reduced, shifted, substituted or interrupted; and (iii) size, type and location of generation to be installed or utilised; and (f) a description of the process for assessing *alternative options* including evaluation	**N/A**

criteria. (27) Before an application notice in relation to the proposed *new large transmission network asset* is published, the *transmission network service provider* must: (a) publish the request for information notice on its website and (b) provide the request for information notice to NEMMCO for publication on the NEMMCO website. (28) The request for information notice must specify a due date for submissions which must be a minimum of 8 weeks after the date the request for information notice is published on NEMMCO's website. (29) Any person may make a written submission to the *transmission network service provider* in response to the request for information notice.	
Transitional provisions (30) This version of the *regulatory test* (version 3) comes into operation from the date of its promulgation, subject to the following transitional provisions which are to be read in conjunction with chapter 11 of the NER. For clarity, version 2 of the *regulatory test* continues to apply in relation to: (a) possible options for which a *distribution network service provider* has commenced consultation under clause 5.6.2(f) or an economic cost effectiveness analysis under clause 5.6.2(g) prior to the promulgation of version 3 of the *regulatory test*; (b) a *new small network asset* for which a *transmission network service provider* has set out the matters required under clause 5.6.2A(b)(4) and (5) in an Annual Planning Report published prior to the promulgation of version 3 of the *regulatory test*; (c) a *new small network asset* not identified in an Annual Planning Report for which a *transmission network service provider* has published a report required under clause 5.6.6A(c) of the NER prior to the promulgation of version 3 of the *regulatory test*; (d) a *new large network asset* for which a *transmission network service provider* has taken an action or commenced a process under the Rules, which relies on or is referenced to, the *regulatory test* (such as publishing an application notice under clause 5.6.6(b)) and is not completed prior to the promulgation of version 3 of the *regulatory test*.	(17) This version of the regulatory test (version 2) comes into operation from the date of its promulgation, subject to the following transitional provisions. The version of the regulatory test in operation immediately prior to the promulgation of version 2 of the regulatory test continues to apply in relation to: (a) possible options for which a *Distribution Network Service Provider* has commenced consultation under clause 5.6.2(f) or an economic cost effectiveness analysis under clause 5.6.2(g) prior to the promulgation of version 2 of the regulatory test; (b) a *new small network asset* for which a *Transmission Network Service Provider* has set out the matters required under clause 5.6.2A(b)(4) and (5) in an Annual Planning Report published before 30 June 2004. The ACCC can substitute a later date if a *Transmission Network Service Provider* does not publish its Annual Planning Report by 30 June 2004 (as required by clause 5.6.2A(a) of the Code); (c) a *new small network asset* not identified in an Annual Planning Report for which a *Transmission Network Service Provider* has published a report required under clause 5.6.6A(c) prior to the promulgation of version 2 of the regulatory test; (d) a *new large network asset* for which a *Transmission Network Service Provider* has published an application notice under clause 5.6.6(b) prior to the promulgation of version 2 of the regulatory test.