AUSTRALIAN ENERGY REGULATOR

Directlink Joint Venture Application for Conversion and Revenue cap

Draft Decision

8 November 2005

Request for submissions

This document sets out the Australian Energy Regulator's (AER) draft decision on the Directlink Joint Venturers' (DJV) application to convert from a market network service to a prescribed service, and to receive a maximum allowed revenue.

The AER does not propose to hold a public forum on this draft decision because issues can be addressed in written submissions. Interested parties are invited to make written submissions to the AER by the closing date **Friday 9 December 2005**.

Submissions can be sent electronically to aerinquiry@aer.gov.au

Alternatively, submissions can be sent to:

Mr Warwick Anderson
A/g General Manager – Access Branch
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PO Box 1199
Dickson ACT 2604

The AER prefers that all submissions be publicly available, to facilitate an informed and transparent consultative process. Submissions will thus be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission, in addition to a confidential subsmission.

All non-confidential submissions will be placed on the AER's website: <http://www.aer.gov.au>.

A copy of DJV's application and additional submissions, consultancy reports and submissions from interested parties are available on the AER's website.

Any enquiries about the draft decision, or about lodging submissions, should be directed to Ms Winifred Jurcevic on (02) 6243 1233.

Contents

Glossary

ABB	ABB Power Systems
AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACG	The Allen Consulting Group
AGSM	Australian Graduate School of Management
AER	Australian Energy Regulator
AR	allowed revenue
BRW	Burns and Roe Worley
capex	capital expenditure
CAPM	capital asset pricing model
code	National Electricity Code
CPI	consumer price index
DC	direct current
DIPNR	Department of Infrastructure, Planning and Natural Resources (New South Wales)
DJV	Directlink Joint Venturers (that is, HQI Australia Ltd Partnership and Emmlink Pty Ltd). For convenience, the two entities are described collectively as DJV and referred to in the singular for this draft decision.
draft SRP	*Draft Statement of Principles for the Regulation of Electricity Transmission Revenues*, 18 August 2004
ERAA	Energy Retailers Association of Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
EUAA	Energy Users Association of Australia
GWh	gigawatt hour

HVDC	high voltage direct current
ICRC	Independent Competition and Regulatory Commission (Australian Capital Territory)
IDC	Interest during construction
IES	Intelligent Energy Systems
IPART	Independent Pricing and Regulatory Tribunal (New South Wales)
IRPC	Inter-Regional Planning Committee
kV	kilovolt
LRMC	long run marginal cost
MAR	maximum allowed revenue
MNSP	market network service provider
MRP	market risk premium
MTC	Murraylink Transmission Company
MVA	mega volt ampere
MW	megawatt
MWh	megawatt hour
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NERA	National Economic Research Associates
NPV	net present value
NSP	network service provider
NSW	New South Wales
ODRC	optimised depreciated replacement cost

ODV	optimised deprival value
OECD	Organisation for Economic Cooperation and Development
opex	operating and maintenance expenditure
PB Associates	Parsons Brinckerhoff Associates
PST	phase shifting transformer
PV	present value
QCA	Queensland Competition Authority
QNI	Queensland – New South Wales Interconnector
RAB	regulated asset base
SNI	South Australia – New South Wales Interconnector
SRMC	short run marginal cost
SRP	*Statement of Principles for the Regulation of Electricity Transmission Revenues*, 8 December 2004
TEUS	TransÉnergie US Limited
TNSP	transmission network service provider
TPA	*Trade Practices Act 1974* (Cwlth)
TUOS	transmission use of system
USE	unserved energy
VENCorp	Victorian Energy Networks Corporation
VOLL	value of lost load
WACC	weighted average cost of capital

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Summary

Overview

On 6 May 2004, Emmlink Pty Ltd and HQI Australia Limited Partnership, the owners of Directlink jointly applied to convert Directlink from an unregulated service to a regulated service. For convenience, the two entities are described collectively as the Directlink Joint Venturers (DJV) and referred to in the singular for this draft decision. The Australian Energy Regulator's (AER) draft decision is that Directlink should be permitted to convert to a prescribed (regulated) service. Upon conversion Directlink's opening regulated asset base (RAB) is to be set at $116.68 million (as at 1 July 2005). This will result in a maximum allowed revenue of around $12.1 million in 2005–06.

Directlink is an electricity transmission line that forms one of the links between the New South Wales (NSW) and Queensland price regions in the National Electricity Market (NEM).

DJV's application has raised a number of complex issues. The AER has carefully considered the objectives of the National Electricity Code (the code) and weighed the interests of all parties in resolving these issues.

The first issue to be resolved is whether Directlink should be permitted to convert. The AER has examined the history and intent of the conversion provision in the code and the approach adopted by the Australian Competition and Consumer Commission (ACCC) in its Murraylink decision for guidance. The AER considers that it is appropriate to assess whether Directlink's network service falls within the category of a prescribed service. The AER has found that Directlink satisfied the definition of a prescribed service and therefore its network service will be a prescribed service from when it ceases to be classified as a market network service.

After deciding to permit conversion it was then necessary to determine an asset value for Directlink. The AER considers that the most appropriate framework for determining an asset value for Directlink would be to apply the regulatory test. This ensures that Directlink is treated consistently with other large network augmentations and the objectives of the code.

Although usually applied to assets prior to construction, the regulatory test can be applied to Directlink to determine whether it is the optimal project or whether some other asset is optimal. The cost of the optimal project can then be used to determine Directlink's asset value. When the AER applied the regulatory test, however, it found no alternative project satisfied the test. That is, under the regulatory test neither Directlink, nor any other alternative should be constructed.

This outcome presented the AER with a difficult issue for consideration. On the one hand it could be argued that Directlink should be provided with an asset value of zero since its construction could not be justified today. However, on the other hand as Directlink already exists and provides benefits to market participants over and above its operating costs, an asset value that is greater than zero would be appropriate.

To resolve this issue the AER examined an economic valuation (EV) of Directlink under the optimised deprival value (ODV) framework for asset valuation. This framework allows a value to be assigned to Directlink that is consistent with the level of market benefits provided by it.

In applying this approach the AER was conscious of the need to avoid adversely affecting incentives for future investment. The AER considers that the valuation is consistent with the principles contained in chapter 6 of the code in that it provides a fair and reasonable risk adjusted cash flow rate of return on efficient investment and balances the interests of transmission network service providers (TNSP) and users.

There is, however, a degree of uncertainty in measuring market benefits depending on the assumptions adopted. In this context the AER examined a number of credible scenarios. From the credible scenarios, the AER has determined the median market benefits to be $150.55 million. From this value, the lifecycle operating cost of $20.60 million is deducted to determine a value of $129.95 million. To this amount, the AER has included an allowance for benchmark equity raising costs of $1.90 million.

Given that Directlink has been in service for about five years, it is appropriate to adjust the asset value for depreciation. This adjustment is consistent with the approach proposed by DJV and provides a depreciated opening asset value of $116.68 million. This asset value has been used to determine a maximum allowed revenue for DJV.

The AER acknowledges that it is a difficult task to determine an appropriate asset value for Directlink. The AER, however, is of the view that the approach it has employed in determining the opening asset value is appropriate and robust for the following reasons:

- Directlink failed to satisfy the regulatory test at the time the application for conversion was considered and therefore some optimisation is appropriate
- applying an EV provides an asset value that is consistent with the level of market benefits provided by Directlink
- applying an EV to set an asset value for Directlink is consistent with the objectives of the transmission revenue regulatory regime.

The proposed asset value of $116.68 million is a fair and reasonable result under these circumstances.

The AER's draft decision approves DJV's request for a 10 year regulatory control period and allows a smoothed revenue allowance for DJV that increases from $12.1 million in 2005–06 to $13.7 million in 2014–15. On average this allowed revenue stream is around 25 per cent less than DJV's requested revenue of $16.5 million in 2005–06 to $18.1 million in 2014–15. The draft decision provides an opex allowance of around $2 million per annum and includes a services standards scheme and a pass through mechanism.

The AER notes, however, that the conversion of Directlink is an option for DJV and that DJV may choose to continue operating as a market network service.

Introduction

Directlink is an electricity network asset that runs between Mullumbimby in the NSW price region and Terranora in the Queensland price region. With a nominal capacity of 180 megawatts (MW), it forms one of the links between these two electricity regions in the NEM. HQI Australia Ltd Partnership and Emmlink Pty Ltd are the owners of Directlink (50 per cent each) and are described collectively as the Directlink Joint Venturers (DJV).

On 22 September 2004, DJV submitted its revised application to the ACCC to convert Directlink's network service from a market network service to a prescribed service in accordance with clause 2.5.2(c) of the code. Upon Directlink's service ceasing to be classified as a market network service, DJV has requested the ACCC to determine that:

- the network service provided by Directlink is a prescribed service for the purpose of the code
- for the provision of this prescribed service, DJV is eligible to receive a maximum allowed revenue from the date of the ACCC's final decision on DJV's application to 30 June 2015.

Schedule 2 of the National Electricity (South Australia) Regulations (as amended by the National Electricity (South Australia) Variation Regulations 2005) sets out transitional and savings provisions relating to the commencement of the National Electricity Law and the National Electricity Rules (NER). It states that for making a determination on the conversion application, the AER is required to take over from the ACCC and make its draft and final decisions as if the relevant provisions were those set out in the code (as at 30 June 2005).

The conversion decision

Under clause 2.5.2(c) of the code, the determination of whether a market network service can be converted to a prescribed service is at the discretion of the AER. No express criteria are provided to guide the AER in its conversion decision.

The AER considers that the history and intent of the conversion provision remain relevant to the consideration of conversion applications. When Directlink and other entrepreneurial (unregulated) interconnectors were built, market network service providers (MNSP) were encouraged despite being considered somewhat experimental—as acknowledged in the National Electricity Code Administrator (NECA) working group's review of arrangements for including MNSPs in the NEM. One means of encouraging these market based investments was to include a conversion provision to ensure market design risks did not inefficiently inhibit investment. In light of these matters, the ACCC, in its Murraylink decision, took a broad interpretation of the NECA working group's intention and decided that it was appropriate to focus its assessment on whether the network service falls within the category of a prescribed service rather than a higher threshold.

Given the early encouragement offered to MNSPs and the implied assurance presented by the conversion provision the AER considers that it remains appropriate to adopt the approach developed for the Murraylink decision—that is, to assess whether the network service is a prescribed service as defined in the code. The AER also considers that public benefit and economic efficiency considerations further guide whether an MNSP should be converted.

The definition of a prescribed service, as derived from the code, is a service that is not:

- a market network service, or
- excluded from the revenue cap under a more light handed regime imposed by the AER under clause 6.2.3(c), or
- found to be contestable under clause 6.2.4(f).

The AER considers that Directlink satisfies each of the three limbs of the definition of a prescribed service. As such, Directlink's network service will be a prescribed service from when it ceases to be classified as a market network service.

Framework for asset valuation

Clause 2.5.2(c) of the code (the conversion provision) states that once a prescribed service is determined:

> … the revenue cap or price cap of the relevant Network Service Provider may be adjusted in accordance with Chapter 6 to include to an appropriate extent the relevant network elements which provided those network services.

In setting a revenue cap for the converting asset, the first step is to identify the framework to determine an appropriate value for the asset. In considering the appropriate framework, the AER has had regard to the guidance provided by the code and the approach adopted in the Murraylink decision (that is, the application of the regulatory test). The AER also considered a number of asset valuation methodologies including optimised deprival value (ODV) and optimised depreciated replacement cost (ODRC).

The AER considers that the most appropriate framework for determining an asset value for Directlink would be to apply the regulatory test. The application of the regulatory test to Directlink:

- would help ensure consistency between the AER's consideration of DJV's application and the approval of other forms of regulated investments. That is, applying the regulatory test to converting network services would prevent an MNSP from being able to bypass the provisions in chapter 5 of the code
- has regard to the Council of Australian Government's (COAG) preference for the deprival value approach to asset valuation—outlined in clause 6.2.3(d)(iv)(A) of the code—because the regulatory test framework provides an outcome that is consistent with the ODV method. That is, where an asset is to be replaced, it will be replaced with the asset that maximises the net present value (NPV) of market benefits. This is equivalent to the asset that has the lowest ODRC.

The regulatory test has two limbs: one relating to augmentations to meet service (reliability) standards and the other relating to new interconnectors or augmentation options. The test in each case is different. In the case of augmentations to meet service standards, the augmentation that minimises the NPV of the cost of meeting the service standards satisfies the test. In all other cases, the test is satisfied by the project that maximises the NPV of market benefit, having regard to alternative projects and market development scenarios.

In circumstances where no asset has been constructed, the regulatory test identifies the optimal project having regard to alternative projects and market development scenarios. Once the optimal project is built, the cost of the project becomes the asset value—that is, the regulated asset base (RAB). However, Directlink is already in service. Nevertheless, a regulatory test can be undertaken as if Directlink had not been constructed. Such an approach will determine whether Directlink is the optimal project at the time of conversion or whether some other asset is preferable. The cost of the optimal project can then be used to determine Directlink's asset value.

In the Murraylink decision, the application of the regulatory test identified an optimal alternative project and the cost of that project was used to determine Murraylink's asset value. In the case of Directlink, however, the application of the regulatory test identified no optimal alternative project for replacing Directlink. That is, none of the projects satisfied the regulatory test because none maximised the NPV of market benefits in most credible scenarios. This also indicates that, under the regulatory test framework, Directlink should not be constructed.

One option for the AER, therefore, would be to allow conversion of Directlink with a zero asset value. The AER, however, is of the view that allowing Directlink to convert but providing DJV with a zero asset value would not encourage the efficient use of existing infrastructure and may be inconsistent with the intention of the MNSP and conversion provisions of the code. The regulator's treatment of existing assets in such a manner could also be perceived as creating an environment of uncertainty which may have an adverse effect on transmission investment incentives in the future. Because investment is susceptible to uncertainty, it may deter future efficient investments in the long term.

The AER is seeking to provide certainty and thereby maintain an environment that is conducive to efficient investment, foster an efficient use of existing infrastructure and achieve reasonable consistency in the outcomes of regulatory processes. In these circumstances, an approach that provides Directlink with an asset value that is greater than zero means market participants benefit in the long term through the encouragement of ongoing investment in the NEM.

Directlink already exists and provides benefits to market participants over and above its operating costs, so an asset value that is greater than zero would be appropriate. As such, the AER considers it appropriate to determine an economic valuation of Directlink under the ODV framework for asset valuation. This allows a value to be assigned to Directlink that is consistent with the level of market benefits provided by it.

The results of the regulatory test assessment and the application of the 'economic value' limb of ODV are discussed below.

The selection of alternative projects

The code requires a proponent of new large network assets to apply the regulatory test, considering 'reasonable network and non-network alternatives' that include (but are not limited to) interconnectors, generation options and demand-side options. The AER considers that the following alternative projects have the requisite level of similarity to Directlink for the regulatory test:

- alternative 0—the existing Directlink first generation high voltage direct current (HVDC) Light link
- alternative 1—a modern HVDC Light link
- alternative 2—a conventional HVDC link
- alternative 3—a 132 kilovolt (kV) high voltage alternating current (AC) link.

Network augmentation deferral benefits

Network augmentation deferral benefits represent the economic savings to the NEM when a link interconnecting two regions provides network support, such that it allows a TNSP to meet its reliability obligations and thus defer network augmentations. DJV and its consultant, Burns and Roe Worley (BRW), listed network augmentations in NSW and Queensland that they claimed Directlink can defer. With the assistance of its consultants Parsons Brinckerhoff Associates (PB Associates) and CHC Associates, the AER has considered the views put forward by DJV and interested parties. The deferral benefits:

- vary depending on demand growth forecasts and the discount rates
- range from $74 million to $113 million for Directlink and alternatives 1 and 2
- range from $21 million to $40 million for alternative 3.

Interregional transfer benefits

Increased interconnection alters the electricity flows across the NEM. Benefits to market participants may accrue to the extent that the altered electricity flows reduces the cost to market participants of generating and supplying electricity. DJV engaged TransÉnergie US (TEUS) to estimate the interregional benefits provided by Directlink and its alternative projects. The AER engaged Intelligent Energy Systems (IES) to assist it to evaluate TEUS's modelling of these benefits. IES identified issues with the input assumptions used by TEUS in its modelling, and noted that aspects of the results were inconsistent with observed market dynamics. As a result, IES advised that the AER could not rely on TEUS's modelling for the regulatory test.

At the request of the AER, DJV agreed to have TEUS undertake additional modelling with revised assumptions. IES reviewed the results of the additional interregional modelling and considered that they were reasonable for the purpose of the regulatory test. The AER has adopted the interregional benefits estimated by TEUS in the additional modelling for Directlink and its alternative projects. These benefits:

- span a wide range and vary depending on assumptions such as demand growth, discount rate, the value of unserved energy (USE)[1] and generator bidding strategy
- range from $21 million to $302 million for Directlink and alternatives 1 and 2
- are around zero for alternative 3 because it does not provide any increase in the interconnection capacity between Queensland and NSW.

The cost of Directlink and its alternative projects

The costs of Directlink and its alternative projects are used in the regulatory test for estimating net market benefits—that is, gross market benefits less gross costs. If an alternative project maximises the net market benefits in most credible scenarios (that is, satisfies the regulatory test), its cost would be used to set the asset value for determining a revenue cap for DJV. The AER considers that the capital costs of Directlink and its alternative projects are as shown in table 1.

Table 1 The AER's conclusion on costs of Directlink and its alternative projects ($ million, 1 July 2005)

Capital cost components	Directlink	Alternative 1	Alternative 2	Alternative 3
Project cost	169.3	241.1	139.2	63.9
IDC	na	13.1	10.2	6.6
Lifecycle opex[(a)]	20.6	20.6	20.6	18.4
Total capital cost	189.9	274.8	170.0	88.9

(a) The opex amount has been calculated as the present value of the annual opex required over the assumed life of the assets (40 years). See chapter 12 for more details on the allowed opex.

na - not applicable.

IDC = interest during construction; opex = operating and maintenance expenditure.

Market development scenarios and sensitivity analysis

The regulatory test requires that alternative market development scenarios be considered. The role of market development scenarios is to capture uncertainty about the future state of the electricity market. The regulatory test also specifies that sensitivity analysis should be undertaken. The role of sensitivity analysis is to test the variability of the gross market benefits to key assumptions.

The AER's regulatory test assessment included 40 market development scenarios, of which six scenarios were considered to be credible. The remaining scenarios were used as sensitivity analysis. The market simulation indicates that the gross market benefits for the credible range of scenarios are:

- $129 million to $257 million for Directlink and alternatives 1 and 2
- $25 million to $36 million for alternative 3. These results reflect that alternative 3 provides no interregional benefits and only limited network deferral benefits.

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1 A measure of the value of electricity to consumers through reductions in lost load.

Ranking of Directlink and its alternative projects

When the net market benefits for each project have been determined, the results can be ranked for each scenario considered. The project that satisfies the regulatory test is the one that maximises the net market benefits in most (although not all) credible scenarios. Table 2 shows the ranking of Directlink and its alternative projects under the six credible scenarios.

Table 2 Net market benefits and rankings for credible scenarios ($ million, 1 July 2005)

Credible scenarios				Net market benefits and rankings							
USE value	Bidding strategy	Discount rate	Demand growth	Directlink (ranking)		Alternative 1 (ranking)		Alternative 2 (ranking)		Alternative 3 (ranking)	
$10 000	Historical	9%	High	67.4	(2)	–17.5	(3)	87.3	(1)	–64.3	(4)
$29 600	Historical	9%	High	50.1	(2)	–34.8	(3)	70.0	(1)	–64.3	(4)
$29 600	Historical	9%	Medium	–24.8	(2)	–109.8	(4)	–4.9	(1)	–61.2	(3)
$10 000	Historical	9%	Medium	–53.8	(2)	–138.8	(4)	–33.9	(1)	–56.1	(3)
$29 600	Historical	9%	Low	–58.1	(3)	–143.1	(4)	–38.2	(1)	–53.4	(2)
$10 000	Historical	9%	Low	–61.0	(3)	–145.9	(4)	–41.1	(1)	–53.4	(2)

Overall, none of the projects satisfied the regulatory test because none of them maximised the net market benefits in most credible scenarios (that is, four out of six scenarios). The regulatory test assessment indicated that no project is optimal and that Directlink would not be justified. Having regard to the conversion provision's intention, the objectives of the code and the transmission revenue regulatory regime, the AER considers that it would be appropriate to provide DJV with an asset value greater than zero but less than the cost of Directlink or one of the alternative projects.

Establishing the asset value

Given the results of the regulatory test assessment, the AER is of the view that the interests of DJV and market participants can be balanced by further considering the ODV method of asset valuation. The application of the 'economic value' limb of ODV, where replacement of Directlink would not be economic, allows an asset value to be assigned to Directlink and provides an outcome that is consistent with the objectives of the transmission revenue regulatory regime. It provides an economic valuation of Directlink by setting the asset value to be consistent with the level of its economic market benefits.

There is, however, a degree of uncertainty in measuring market benefits. The value of market benefits of Directlink spans a wide range depending on the assumptions adopted. Therefore, the market benefits need to be estimated for several scenarios. Under the regulatory test framework, the AER considered six credible scenarios. In determining an EV, it is normal practice to identify the most likely scenario to establish a 'fair value'. As shown in table 3, the estimated total market benefits of Directlink span a wide range under the credible scenarios. It is not possible to select the most likely scenario with a reasonable degree of certainty. Therefore, for the purposes of determining the EV of Directlink, the AER considers that the six credible scenarios remain relevant.

Table 3 Total estimated market benefits of Directlink ($million, 1 July 2005)

Credible scenarios				Market benefits of Directlink		
USE value	Bidding strategy	Discount rate	Demand growth	Deferral benefit (a)	Interregional benefit (b)	Total benefit (a)+(b) [1]
$10 000	Historical	9%	High	83.3	174.1	257.3
$29 600	Historical	9%	High	83.3	156.8	240.0
$29 600	Historical	9%	Medium	95.6	69.4	165.0
$10 000	Historical	9%	Medium	95.6	40.4	136.1
$29 600	Historical	9%	Low	106.1	25.7	131.8
$10 000	Historical	9%	Low	106.1	22.8	128.9

1 Total benefit may not add exactly due to rounding.

From the credible scenarios, the AER has determined the median market benefits to be $150.55 million in its assessment of Directlink's EV. From this value, the lifecycle operating cost of $20.60 million is deducted to determine a value of $129.95 million.

To this amount, the AER has included an allowance for benchmark equity raising costs of $1.90 million. Given that Directlink has been in service for about five years, however, it is appropriate to depreciate the opening asset value. This adjustment is consistent with the approach proposed by DJV and provides a depreciated opening asset value of $116.68 million. This asset value will be used to determine a maximum allowed revenue for DJV.

Operating and maintenance expenditure

The allowed revenue for DJV is set by reference to the optimised project cost and efficient opex for Directlink. The AER considers an appropriate opex allowance would be around $2 million per annum. This allowance includes benchmark debt raising costs averaging $0.06 million per annum and additional amounts of $0.2 million in both 2010–11 and 2011–12 for equipment replacements.

The cost of capital

The AER has adopted the post-tax approach to setting the weighted average cost of capital (WACC), as proposed by DJV. The WACC parameters have been calculated in accordance with the AER's *Statement of Principles for the Regulation of Electricity Transmission Revenues—Background Paper* (SRP) on the basis of benchmark parameters and to enhance certainty. Some parameters vary over time, according to market conditions. They have been calculated as at 28 October 2005. The AER considers that a nominal vanilla WACC of 8.40 per cent, comprising a post-tax nominal return on equity of 11.50 per cent and a pre-tax cost of debt of 6.34 per cent, provides an appropriate cost of capital for DJV. When finalising its decision, the AER will update the WACC for the prevailing market bond yields.

Service standards

Under a revenue cap regime, the only way TNSPs can increase their revenues (for regulated activities) is by reducing their costs. Such cost reductions could result in a decline in service quality, which can impose costs on other market participants. As a result of these incentives, the AER includes service standards in revenue caps to maintain service quality.

Circuit availability is the applicable performance measure to apply to Directlink because it provides an incentive to maximise the amount of time and capacity that the network asset is available. It comprises three submeasures: scheduled, peak forced and off-peak forced.

Based on the advice of PB Associates and a comparison with Murraylink's performance targets, the AER considers DJV's proposed targets are appropriate. In accordance with clause 6.2.5 of the NER and the service standards guidelines, all measures should be recorded and reported each calendar year.

Pass-through mechanism

A pass-through mechanism allows a TNSP's revenue to be adjusted during the regulatory period when a specified risk eventuates. The AER has included a pass-through mechanism in the draft decision for DJV. The pass-through mechanism is based on TransGrid's and EnergyAustralia's revenue caps (2004–05 to 2008–09) but has been adjusted to reflect the circumstances of Directlink. In particular, pass-through events have been limited to events that occur after the date of the final decision, and a materiality requirement has been further defined.

Total revenue

The AER considers that DJV's request for a 10 year regulatory control period is justified, given the limited scope for efficiency gains, the enhanced certainty for DJV and the regulatory cost savings. Based on its assessment of the building block components, the AER has forecast a smoothed revenue allowance for the Directlink Joint Venturers that increases from $12.1 million in 2005–06 to $13.7 million in 2014–15 as shown in table 4.

Table 4 The AER's draft decision on allowed revenue ($ million, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Return on capital	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.7	9.7	9.6
Return of capital	–0.1	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.8
Operating expenses	2.0	2.1	2.2	2.2	2.3	2.6	2.6	2.5	2.5	2.6
Taxes payable	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.1
Franking credits	–0.4	–0.4	–0.4	–0.4	–0.5	–0.5	–0.5	–0.5	–0.5	–0.5
Unsmoothed allowed revenue	12.1	12.3	12.4	12.6	12.8	13.2	13.3	13.2	13.4	13.6
Smoothed allowed revenue	12.1	12.3	12.5	12.6	12.8	13.0	13.2	13.3	13.5	13.7

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Part A – Background

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1 Introduction

1.1 Background

Directlink is an electricity network asset that runs between Mullumbimby in the New South Wales (NSW) price region and Terranora in the Queensland price region. With a nominal capacity of 180 megawatts (MW), it forms one of the links between these two electricity regions in the National Electricity Market (NEM). HQI Australia Ltd Partnership and Emmlink Pty Ltd are the owners of Directlink (50 per cent each).[2] For convenience, the two entities are described collectively as the Directlink Joint Venturers (DJV) and referred to in the singular for this draft decision.

Directlink's network service is currently classified as a market network service. It earns revenue from the NEM by providing this service between the NSW and Queensland regions. On 6 May 2004, DJV submitted its application to the Australian Competition and Consumer Commission (ACCC) to convert Directlink to a prescribed service in accordance with clause 2.5.2(c) of the National Electricity Code (the code). Then, in light of the proposed Greenbank augmentations in south east Queensland, DJV advised the ACCC that it would provide a supplementary submission that took account of this information. On 30 August 2004, the ACCC requested that DJV submit a revised application to facilitate an assessment by the ACCC, its consultants and interested parties. DJV agreed to this request.

On 22 September 2004, DJV submitted a revised application for the conversion of Directlink from a market network service to a prescribed service. Upon Directlink's service ceasing to be classified as a market network service, DJV requested the ACCC to determine that:

- the network service provided by Directlink is a prescribed service for the purpose of the code
- to provide this prescribed service, DJV is eligible (subject to its performance incentive scheme) to receive the maximum allowed revenue from transmission customers through a coordinating transmission network service provider, for a regulatory period from the date of the ACCC's final decision on DJV's application to 30 June 2015.

1.2 Transitional provision

Schedule 2 of the National Electricity (South Australia) Regulations (as amended by the National Electricity (South Australia) Variation Regulations 2005) sets out transitional and savings provisions relating to the commencement of the National Electricity Law (NEL) and the National Electricity Rules (NER).

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[2] Emmlink Pty Ltd is 100 per cent owned by Country Energy. HQI Australia Ltd Partnership is 66.67 per cent owned by Hydro–Québec International and 33.33 per cent owned by Le Fonds de Solidarité des Travailleurs du Québec.

Clause 13(6) of this schedule states:

> Despite subclauses (3) and (5), if the ACCC had taken action for the purpose of making a determination under clause 2.5.2(c) of the Code and a consequent revenue cap determination in accordance with Chapter 6 of the Code and had not published a draft or final determination in respect of the matter before the commencement date of the new National Electricity Law, then the AER [Australian Energy Regulator] must take any action after the commencement date for the purpose of making any such determination, and make any such determination, in respect of the matter as if the provisions that apply are those of the Code as in force immediately before the commencement date (and not those of the new National Electricity Law or the Rules).

In relation to DJV's application, the ACCC had commenced actions to make a determination under clause 2.5.2(c) and a consequent revenue cap decision in accordance with chapter 6 of the code. These actions have included:

- publishing DJV's application and inviting submissions in May and September 2004
- commissioning consultancy reviews of DJV's application.

Section 1.3 details the review process.

At 1 July 2005 (the commencement date for the NEL and the NER), the ACCC had not published a draft or final decision on DJV's application. The Australian Energy Regulator (AER) is thus required to make its draft and final decisions as if the relevant provisions are those set out in the code (at 30 June 2005) and not those of the new NEL or the NER. The AER has published this draft decision, and will proceed to its final decision, on that basis.

Work by the ACCC in assessing DJV's application is deemed to have been done by the AER. To the extent that past work was conducted by the ACCC, this draft decision will refer to the ACCC to be historically accurate.

1.3 The review process

The code does not set out specific criteria for the conversion of a market network service provider (MNSP) to a prescribed service. In February 2003, however, the ACCC released an issues paper to guide interested parties on the administration of relevant provisions of the code.[3] It used this paper as a basis for assessing the Murraylink Transmission Company's application for conversion of the Murraylink interconnector.

In the Murraylink decision, the process involved determining whether the assets could be classified as providing a prescribed service in accordance with the code's relevant provisions and definitions. The ACCC noted that if the interconnector was determined to provide a prescribed service, it would set an asset value based on the option that maximised the net present value of the market benefits. The AER has been guided by this same process when assessing DJV's application.

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3 ACCC, *Issues Paper: Murraylink Transmission Partnership—Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue*, Canberra, 5 February 2003.

The ACCC engaged three consultants to assist its review of DJV's application. Parsons Brinckerhoff Associates helped the ACCC review the alternative projects and level of network support proposed by DJV, for the purposes of applying the regulatory test and looking at possible alternatives that could be considered. It also advised on the appropriate service standards to be applied to DJV. Intelligent Energy Systems assisted the ACCC to review and determine the interregional market benefits of the alternative projects. CHC Associates Pty Ltd provided technical and engineering advice throughout the review process. Appendix A summarises the consultation undertaken for the consideration of DJV's application.

1.4 Classification of network services under the code

The code establishes two frameworks for the development of network services in the NEM: regulated and unregulated network services. An entity that owns, operates or controls either a transmission or distribution system must register with the National Electricity Market Management Company (NEMMCO) as a network service provider (NSP).[4] Services subject to a revenue cap under chapter 6 of the code are referred to as prescribed services.[5] An NSP may classify its network services as market network services, however, if the provisions in clause 2.5.2(a) of the code are satisfied. A market network service is exempt from the pricing regulations detailed in chapter 6.[6]

Clause 2.5.2(a) of the code states that an NSP may classify its network services as market network services if, and only if:

> (1) the relevant network service is to be provided by network elements which comprise a two-terminal link and do not provide any prescribed service or prescribed distribution service;
>
> (2) the Network Service Provider is registered under clause 2.5.1 in respect of the network elements which provide the relevant market network service and the Network Service Provider has provided an access undertaking to the ACCC in respect of the relevant market network service provided by those network elements as required under clause 5.2.3(a2);
>
> (3) the relevant network service must;
>
> (A) not have ever been a prescribed service or a prescribed distribution service; or
>
> (B) be ineligible to be such a service;
>
> (4) the connection points of the relevant two-terminal link must be assigned to different regional reference nodes; and
>
> (5) the relevant two-terminal link through which the network service is provided;
>
> (A) does not form part of a network loop; or
>
> (B) must be an independently controllable two-terminal link,
>
> and must have a registered power transfer capability of at least 30MW.

4 National Electricity Code, clause 2.5.1(a).
5 ibid., chapter 10, 'Glossary'—see 'prescribed services'.
6 ibid., clauses 2.5.2(b) and 6.1.4(a).

MNSPs are technically different from typical transmission services that are developed in line with chapter 5 of the code. Chapter 5 generally applies to network infrastructure for the conveyance of electricity to customers, or to connections between that infrastructure and either generators or customers. According to the above criteria, MNSPs enable the independently controllable transfer of power between different regions of the NEM. A regulated link, on the other hand, would operate its network service in accordance with market dispatch determined by NEMMCO.

Regulated transmission services earn revenue determined by the AER in accordance with chapter 6 of the code. Unregulated services earn revenue from trading in the wholesale electricity market in accordance with chapter 3 of the code. MNSPs rely on the spot price differential between two regions, or contractual arrangements, to earn revenue.

1.5 Conversion provision

Clause 2.5.2(c) gives the ACCC the discretion to determine whether a market network service can be classified as a prescribed service. It also allows the ACCC to adjust the revenue cap of the relevant NSP in accordance with chapter 6 of the code:

> If an existing network service ceases to be classified as a market network service it may at the discretion of the Regulator or Jurisdictional Regulator (whichever is relevant) be determined to be a prescribed service or prescribed distribution service in which case the revenue cap or price cap of the relevant Network Service Provider may be adjusted in accordance with Chapter 6 to include to an appropriate extent the relevant network elements which provided those network services.[7]

However, as discussed in section 1.2, the AER is now the relevant regulator for making a decision in accordance with clause 2.5.2(c). It must decide:

1. whether to allow the MNSP to convert to a prescribed service (the conversion decision)

2. the revenue cap for the converted MNSP (the asset valuation and revenue cap decision).

The first decision considers a broad range of factors to inform the general principles for conversion. These factors include:

- the regulatory framework administered by the AER

- the purpose and history of the MNSP and conversion provisions

- the ACCC's Murraylink decision.

Having regard to these principles, the conversion decision assesses whether an MNSP's service meets the category of a 'prescribed service'. The second decision considers the appropriate asset value (or regulated asset base) and the subsequent

[7] Chapter 10 of the code defines 'regulator' to be the ACCC after 1 July 1999.

maximum allowed revenue. The maximum allowed revenue is determined in accordance with the accrual building block approach (see chapter 14).

1.6 Structure of the document

This draft decision sets out the AER's consideration of DJV's application and consists of four parts. Part A contains chapters 1 and 2, which set out the background material:

- Chapter 1 outlines the application, the review process, and provides background to the relevant code (now NER) provisions.
- Chapter 2 provides an overview of Directlink and the AER's consideration of whether it satisfies the definition of a transmission network.

Part B contains chapters 3 and 4, which discuss the AER's conversion decision:

- Chapter 3 outlines the appropriate framework and principles for conversion of Directlink to a prescribed service.
- Chapter 4 contains the AER's decision on the conversion of Directlink to a prescribed service.

Part C contains chapters 5–11, which discuss the AER's application of the regulatory test and the appropriate asset value for Directlink:

- Chapter 5 outlines the proposed method for setting the asset value and an overview of the regulatory test.
- Chapter 6 contains the AER's assessment of the selection of alternative projects
- Chapter 7 provides the AER's consideration of the transmission network augmentation deferral benefits.
- Chapter 8 provides the AER's consideration of the interregional transfer benefits.
- Chapter 9 provides the AER's consideration of the cost of alternative projects.
- Chapter 10 provides the AER's consideration of market development scenarios and sensitivity analysis.
- Chapter 11 ranks alternative projects and sets out the approach to establishing an asset value for Directlink.

Part D contains chapters 12–16, which discuss the AER's revenue cap decision:

- Chapter 12 considers operating and maintenance expenditure.
- Chapter 13 considers the appropriate weighted average cost of capital.
- Chapter 14 contains the AER's assessment of each of the building block elements and the maximum allowed revenue.

- Chapter 15 sets out the appropriate service standards.
- Chapter 16 sets out the pass-through rules.

Appendixes A–K are attached to this draft decision.

2 Directlink

2.1 Introduction

This chapter provides an overview of Directlink and explains the AER considerations of Directlink as a transmission network. It is set out as follows:

- overview (section 2.2)
- classification of Directlink as a transmission network (section 2.3).

2.2 Overview

Directlink is a privately funded electricity network asset—with a current total nominal rated capacity of 180 megawatts (MW)—owned and operated by DJV. It came into operation in July 2000 and consists of underground cables that transfer power between Terranora and Mullumbimby through converter stations at Bungalora and Mullumbimby. The Directlink cables are buried underground or laid in galvanised steel ducting for its entire length of 63 kilometres, along roads and railway tracks.

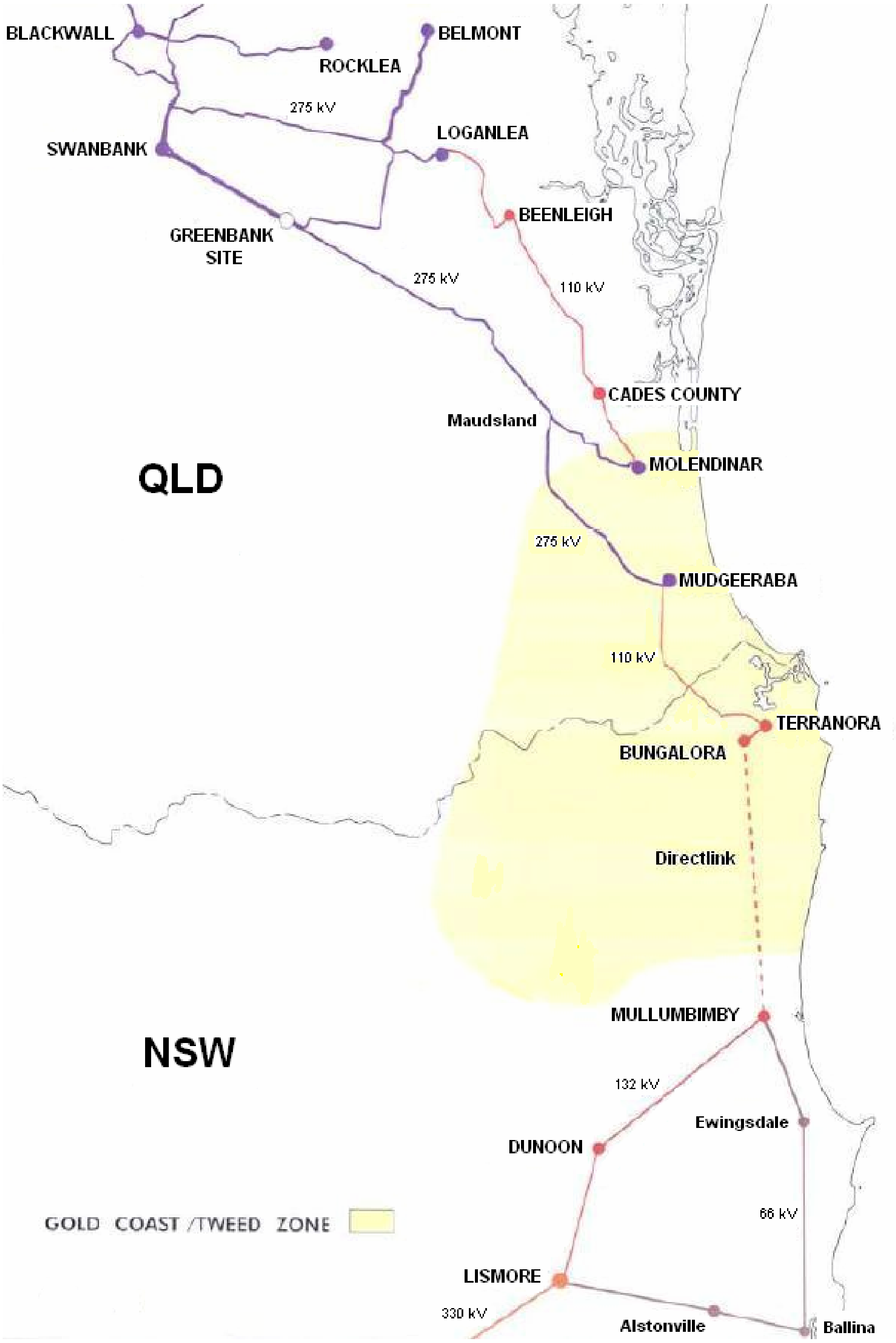
Directlink uses the ABB Power Systems' high voltage direct current (HVDC) transmission technology known as HVDC Light. This technology has been designed to meet both high reliability and technical standards. It has been used in Australia, the United States and Sweden. TransÉnergie (owned by Hydro–Québec International) used the technology for the Murraylink interconnector project in Australia and the Cross Sound cable project between Long Island (New York) and Connecticut in the USA.

A HVDC Light system consists of two elements:

1. converter stations (one at each end of the system) that convert alternating current (AC) electrical energy to direct current (DC) electrical energy, and vice versa
2. a pair of DC transmission cables.

Directlink comprises three HVDC Light systems between Bungalora and Mullumbimby, each with a capacity of 60 MW, together with an AC cable between Terranora and Bungalora (see appendix B for a system diagram). Figure 2.1 shows the location of Directlink in the NEM. In that figure, the 275 kilovolt (kV) lines into Belmont, Loganlea, Molendinar and Mudgeeraba are owned by Powerlink, as is the 110 kV line from Mudgeeraba to the border. Other lines in south east Queensland are owned by Energex, but not all are shown. Country Energy owns the lines in New South Wales (NSW) from the border to Lismore (excluding Directlink). And TransGrid owns the 330 kV line into Lismore. (TransGrid's 132 kV lines into Lismore from Tenterfield and Koolkhan are not shown.)

Figure 2.1 Directlink's location in the NEM



Source: Powerlink and Energex, *Proposed New Large Network Asset—Gold Coast and Tweed Areas Final Report*, July 2004, p. 10.

2.3 Classification of Directlink as a transmission network

As shown in figure 2.1, Directlink connects to Country Energy's distribution network at Terranora and Mullumbimby. Some interested parties have questioned whether Directlink meets the National Electricity Code (the code) definition of a transmission network. The code defines a transmission network to be:

> A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus:
>
> (a) any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network
>
> (b) any part of a network operating at nominal voltages between 66 kV and 220 kV that does not operate in parallel to and provide support to the higher voltage transmission network but is deemed by the Regulator to be part of the transmission network.[8]

2.3.1 DJV's application

DJV stated that Directlink is a transmission network as defined in the code. First, it stated that Directlink operates at 80 kV DC, which is between 66 kV and 220 kV. As noted by DJV, the code makes no distinction between DC and AC voltages. Second, DJV stated that the circuit path created by the 132 kV circuits between Mullumbimby and Lismore, Directlink and the 110 kV circuits between Terranora and Mudgeeraba operates in parallel with the Queensland – NSW Interconnector (QNI) and can support the transmission network. It stated that Directlink, when flowing north, supports voltage levels in the Gold Coast and alleviates loading on Powerlink's 275 kV system. When Directlink is flowing south, it supports voltage in the far north coast of NSW and alleviates loading on TransGrid's 330 kV line from Armidale to Lismore, and the 132 kV system.

2.3.2 Submissions

TransGrid and NEMMCO noted that Directlink connects to Country Energy's distribution assets (with distribution connection points at Mullumbimby and Terranora).[9] NEMMCO also noted that the code defines an interconnector as a transmission line or group of transmission lines that connects transmission networks in adjacent regions. On this basis, it stated that Directlink arguably would not meet the definition of a regulated interconnector under the code if it converted to a prescribed service.

TransGrid stated that Directlink forms a link that is wholly within the Country Energy distribution network. It argued that if Directlink is to be regarded as a transmission asset, then the distribution assets that connect it to the transmission networks in NSW and Queensland should also be regarded as transmission assets. TransGrid stated that this would be the preferred outcome of the conversion process,

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8 National Electricity Code, chapter 10, 'Glossary'—see 'transmission network'.

9 TransGrid, *Directlink Application for Conversion to a Prescribed Service*, Sydney, 3 June 2004; NEMMCO, *Directlink Application for Conversion to a Prescribed Service*, Sydney, 4 June 2004, p. 3.

with Directlink then forming a 'genuine transmission interconnection' from Queensland to NSW. NEMMCO noted that an option would be to have the link from Lismore to Mudgeeraba declared as transmission rather than distribution. It stated that this option would require physical metering arrangements to be changed and a lead time of 12–18 months.

2.3.3 The AER's considerations

Having reviewed the submissions and the code, the AER considers that Directlink satisfies the definition of a transmission network. Directlink meets the elements of part (a) of the definition of transmission network—that is, it:

- forms part of a network operating at a nominal voltage between 66 kV and 220 kV
- operates in parallel to, and provides support to, the higher voltage transmission network (that is, it operates in parallel to QNI, supports the Queensland network when flowing north and supports the NSW network when flowing south).

NEMMCO noted that Directlink connects to Country Energy's distribution network and, on this basis, arguably would not satisfy the code definition of an interconnector. The AER considers that it is not a necessary condition that a regulated network meets the definition of a regulated interconnector, even though Directlink, as a market network service provider, functions as an interconnector for the purpose of transferring energy between regions. It notes that the code definition of 'regulated interconnector' is an interconnector that is deemed to be a regulated interconnector under clause 6.19 of the code. In turn, clause 6.19 of the code deems that all existing interconnectors that formed part of the power system in the participating jurisdictions on authorisation of the code on 31 December 1997 are regulated interconnectors. Accordingly, this clause does not apply to Directlink.

As noted, it has been argued that if Directlink is to be regarded as a transmission asset, Country Energy's lines connecting to Directlink should also be regarded as transmission under the code. The AER considers, however, that this matter is not directly relevant for assessment of DJV's application, but rather is a technical market operational matter. It is aware that Country Energy has recognised that the 132 kV circuits between Mullumbimby and Lismore and its proportion of the 110 kV circuits between Terranora and Mudgeeraba are transmission assets. Country Energy has sought to acknowledge this formally by lodging documentation with NEMMCO to establish new transmission connection points at Lismore, Dunoon, Mullumbimby and Terranora. When these connection points are established, the Country Energy assets and Directlink will be operated as part of the transmission network.

2.3.4 Conclusion

The AER considers that Directlink satisfies the code's definition of transmission network for the purposes of conversion.

Part B – Conversion decision

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3 General principles for conversion

3.1 Introduction

Under the National Electricity Code (the code), if an existing network service ceases to be classified as a market network service, the relevant regulator has discretion to determine it to be a prescribed service. Specifically, clause 2.5.2(c) states that:

> If an existing network service ceases to be classified as a market network service it may at the discretion of the Regulator or Jurisdictional Regulator (whichever is relevant) be determined to be a prescribed service or prescribed distribution service in which case the revenue cap or price cap of the relevant Network Service Provider may be adjusted in accordance with Chapter 6 to include to an appropriate extent the relevant network elements which provided those network services.

The AER is the regulator for the purposes of this clause. The determination of whether a market network service is to be a prescribed service is thus at the discretion of the AER. The code provides no express criteria to guide the AER in its decision on whether a market network service should be 'converted' to a prescribed service. This chapter sets out the AER's consideration of the general principles for conversion, in light of the AER's discretion under the code. It discusses:

- the regulatory framework administered by the AER (section 3.2)
- the purpose and history of the MNSP and conversion provisions (section 3.3)
- the previous ACCC approach—specifically, the ACCC's Murraylink decision (section 3.4)
- DJV's application for conversion (section 3.5)
- submissions (section 3.6)
- the AER's considerations (section 3.7)
- the conclusion (section 3.8).

Chapter 4 sets out the AER's application of those principles to DJV's conversion application.

3.2 Regulatory framework administered by the AER

The conversion provision outlined above sits within the broader transmission regulatory framework administered by the AER. The AER considers that it is appropriate to consider conversion in this broader framework, which includes:

- objectives of the NEM
- objectives of the pricing regulations (from chapter 6 of the code)

- objectives of the transmission revenue regulatory regime administered by the AER (from chapter 6 of the code).

The following objectives in clause 1.3(b) of the code relate primarily to the intended structure of the NEM:

> (1) the market should be competitive;
>
> (2) customers should be able to choose which supplier (including generators and retailers) they will trade with;
>
> (3) any person wishing to do so should be able to gain access to the interconnected transmission and distribution network;
>
> (4) a person wishing to enter the market should not be treated more favourably or less favourably than if that person were already participating in the market;
>
> (5) a particular energy source or technology should not be treated more favourably or less favourably than another energy source or technology; and
>
> (6) the provisions regulating trading of electricity in the market should not treat intrastate trading more favourably or less favourably than interstate trading of electricity.

Clause 6.1.1(c) of the code states that the objectives to be achieved by applying the transmission and distribution pricing provisions are:

> (1) efficiency in the use, operation, and maintenance of, and investment in, the network, and in the location of generation and demand;
>
> (2) upstream and downstream competition;
>
> (3) price stability; and
>
> (4) equity.

Clause 6.2.2 sets out the objectives of the transmission revenue regulatory regime. Consistent with the objectives set out in clauses 6.1.1(c) and 1.3(b), the objectives of that regime emphasise efficiency and a balancing of the interests of network owners and users. Chapter 5 of this document discusses the objectives of the revenue regulatory regime in further detail.

3.3 Purpose and history of the MNSP and conversion provisions

In February 1997, the National Electricity Code Administrator (NECA) initiated a major review of transmission and distribution pricing. As part of that review, a working group formed in August 1998 to consider interregional hedges and entrepreneurial (unregulated) interconnectors. In November 1998, the working group released its review of arrangements for including entrepreneurial interconnectors or market network service providers (MNSPs) in the NEM.

These arrangements were referred to as ‘safe harbour’ provisions. Network service providers (NSP) able to satisfy these arrangements would be exempt from the revenue regulations in chapter 6 of the code. In other words, the provisions were a ‘safe harbour’ from the revenue regulation under the code, allowing MNSPs to earn unregulated revenue. Without this exemption, MNSPs would be regulated and thus, by definition, would not exist. The working group also provided that MNSPs may relinquish their 'safe harbour' from regulation and convert to a prescribed status. The AER notes that the term 'safe harbour' does not refer to the conversion provision, but rather to clause 2.5.2(a) of the code.[10]

The working group stated that MNSPs are somewhat 'experimental' and may face risks (in addition to normal commercial risks) due to 'market design deficiencies that may only become apparent once the first interconnectors are operational'. The purpose of the conversion provision was expressed in the following terms:

> Providing a right to apply for regulated status may help ensure that investment is not inefficiently inhibited by such non-commercial market design risks. However, it is important that the conversion option should not shield the proponent from normal commercial risks, e.g. the risk of having overjudged the future demand for the interconnection service. It is therefore essential that the regulated revenue entitlement is based on the assessed need for the facility at the time of the application, rather than guaranteeing a return on the original capital cost.[11]

On 21 September 2001, the ACCC authorised changes to the code to introduce the provisions proposed by the working group. Consistent with the working group, the ACCC noted that the conversion provision is intended to protect MNSPs from risks associated with market design issues. In its determination, the ACCC outlined the purpose of the conversion provision:

> In terms of overall philosophy the proposed arrangement to allow switching from a market to a prescribed network service seem at odds with the general direction of the market and the move towards greater provision of market based arrangements where possible. However, the Commission understands that the provision to allow market network services to apply for conversion to prescribed network services reflects the view that MNSPs may face risks from future NEM developments, such as changes to regional boundaries, which may result in market network services becoming non-code compliant. The Commission notes that as the clause is currently drafted no justification is required prior to reclassifying a market network service as a prescribed network service, although the regulator has the discretion to determine whether or not a network service may be classified as a prescribed network service.[12]

In its December 2003 report to the Council of Australian Governments (COAG), the Ministerial Council on Energy agreed to a package of reforms addressing seven key transmission issues. It stated that the arrangements for the co-existence of regulated and market provision of transmission services had not resulted in optimal outcomes. It supported the removal of biases towards unregulated investment, including the development of code changes that establish a level playing field for regulated and market transmission services. The code changes would recognise and protect the rights of existing investors in market transmission services.[13] This change in policy framework suggests that the concept of unregulated interconnectors has not achieved the intended outcomes.

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[10] NECA Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors, *Entrepreneurial Interconnectors: Safe Harbour Provisions*, Adelaide, 1998, p. 2.

[11] ibid., p. 9.

[12] ACCC, *Applications for Authorisation: Amendments to the National Electricity Code—Network Pricing and Market Network Service Providers*, Canberra, 21 September 2001, p. 137.

[13] Ministerial Council on Energy, *Report to the Council of Australian Governments: Reform of Energy Markets*, 11 December 2003, p. 11.

3.4 Previous ACCC approach to conversion—the Murraylink decision

The ACCC considered one application for conversion under clause 2.5.2(c) of the code. On 18 October 2002, the Murraylink Transmission Company (MTC) applied to convert the Murraylink high voltage direct current (HVDC) link between South Australia and Victoria from a market network service to a prescribed service. In its decision of 1 October 2003, the ACCC allowed Murraylink to convert to a prescribed service.[14] It then determined the MTC's revenue cap in accordance with chapter 6 of the code.

At that time, the ACCC noted that no express criteria exist to guide the regulator's conversion decision. Its approach, therefore, was to determine whether Murraylink fell into the category of 'prescribed service' as defined by the code. The ACCC considered that this approach was consistent with clause 2.5.2(c) and the intent of the NECA working group. In summary, the ACCC noted that:

- the NECA working group intended to provide a right for an MNSP to apply for conversion to ensure investment is not inefficiently inhibited

- the authorisation of the network pricing and MNSP code changes containing the conversion provision signalled that conversion would be an option for an MNSP, and that the ACCC would consider conversion on a case-by-case basis. Given the NECA working group's apparent intention, it would have been inconsistent for the ACCC to then set a higher threshold for assessing the MTC's conversion application.

- the ACCC's approach would help ensure consistency between its consideration of MTC's application and the approval of other forms of regulated investments. That is, the application of the regulatory test to converted services would prevent an MNSP from being able to bypass the provisions in chapter 5 of the code. (Chapters 5–11 discuss the application of the regulatory test to DJV.)

- conversion, by reducing the investment risks faced by MNSPs, encourages efficient transmission investment in the NEM.

In considering whether Murraylink fell into the category of prescribed service, the ACCC noted that the 'safe harbour' provisions effectively exempted an MNSP from classification as a prescribed service. However, it was clear that MTC proposed to change Murraylink's classification if the conversion application was successful. In these circumstances, the question was whether Murraylink would exhibit the characteristics of a prescribed service if it were no longer covered by the 'safe harbour' provisions.

The ACCC identified relevant code provisions that preclude a service from being a prescribed service for which a revenue cap is set. From these provisions, it defined a prescribed service as a service that is not:

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[14] ACCC, *Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue*, Canberra, 1 October 2003, p. 25.

- a market network service, or
- excluded from the revenue cap under a more light handed regime imposed by the ACCC, or
- contestable.

The ACCC also stated that the objectives of the transmission revenue regulatory regime set out in chapter 6 of the code, which are underpinned by Part IIIA of the *Trade Practices Act 1974* (TPA) access regime, offered further guidance on whether Murraylink should have been converted to a prescribed service. In particular, it noted the principles and objectives set out in clause 6.2.2 of the code (discussed below).

3.5 DJV's application

In its application (dated 22 September 2004) for conversion to a prescribed service and establishment of a maximum allowed revenue to 30 June 2015 (under the revised application), DJV anticipated that the ACCC would apply the same criterion used in the Murraylink decision. Its application, therefore, focused on the question of whether Directlink's network service would be a prescribed service once it ceased to be classified as a market network service. That is, would Directlink exhibit characteristics that are consistent with the definition of a prescribed service? DJV concluded that its network service, after ceasing to be classified as a market network service, would exhibit the characteristics of a prescribed service.[15] This is discussed in chapter 4.

3.6 Submissions

The submissions received by the AER did not focus on the principles for conversion.

TXU did not dispute Directlink's right to convert to a prescribed service under the code and noted that the Murraylink decision established regulatory precedent for a MNSP's right to convert to a regulated status.[16] In a further submission, TXU stated that it 'has some concerns regarding an MNSP's right to convert to a prescribed service as established by the precedent set in the Murraylink decision, because it creates quite ambiguous outcomes in some critical parts of the conversion'.[17] However, these concerns are more relevant to the application of the regulatory test and the amount of benefits claimed under that test (discussed in chapter 5).

The Energy Users Association of Australia (EUAA) expressed concern about the ACCC's approach to the Murraylink decision. In particular:

> … no public benefits test was applied to Murraylink's conversion.

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15 DJV, *Application for conversion to a Prescribed Service and a Maximum Allowable Revenue to June 2015*, Port Macquarie, 22 September 2004, pp. 4, 17.

16 TXU, *TXU Submission to the ACCC Directlink Joint Venture Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2005–2014*, Melbourne, 4 June 2004, p. 1.

17 id., *TXU's Submission to Intelligent Energy System's (IES) review of the interregional market benefits of Directlink*, Melbourne, 17 May 2005, p. 1.

> We urge the ACCC to ensure that Directlink's conversion is not purely based on the assumption that a TNSP [transmission network service provider] is entitled to convert and hence they will grant the application as long as they meet the prescribed services test. Rather, the Directlink conversion should be assessed on whether it provides a public benefit.
>
> Further, Directlink should be required to show changes in market conditions from the time they began operations as a MNSP to the present situation that has led them to apply for conversion. Based on the changes in market conditions, Directlink then should be required to show a public benefit in price and/or reliability from conversion to justify the granting of the application.
>
> Otherwise, merchant links based on strong initial cash flows might be built only to see the well-known vagaries of the NEM spot market destroy these with the owner then making use of the option to convert to regulated status.[18]

The EUAA noted that its key constituents are energy users and stated:

> First and foremost, the EUAA would expect the ACCC to only permit conversion on the basis of a thorough analysis ensuring that customers benefit from conversion more than they do by either having Directlink remain a merchant link or from the alternatives to Directlink, i.e. a rigorous application of the regulatory test principles.[19]

It submitted that Directlink should be required to show a public benefit in terms of price and/or reliability, but did not expressly define what it meant by the term 'public benefit' and did not propose other factors that would be relevant to deciding whether a conversion application meets a public benefit criterion. It is not immediately apparent whether the EUAA was proposing that 'public benefit' should be equated with 'customer benefits' in the present context.

In response to the submission that conversion should be assessed on whether it provides a benefit to the public, DJV submitted that the public is benefited by the ACCC employing sound decision making principles for conversion, as it did for the Murraylink decision, and ensuring reasonable certainty and consistency of regulation over time, as required by the code.[20] It submitted that the rationale that the ACCC applied in the Murraylink case is just as valid for Directlink.

In response to the submission that DJV should be required to show that market conditions have changed from the time it began operating as an MNSP, DJV submitted that 'it is clear from the safe harbour provisions, the ACCC's previous statements and the Murraylink decision that DJV may apply for a conversion at any time and no separate justification is required'.[21] It stated that the ACCC has applied a threshold for conversion that is no lower than the NECA working group had contemplated.

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18 EUAA, *Directlink—Application for Conversion to Regulated Status: Application and ACCC Issues Paper, Response by the Energy Users Association of Australia*, Box Hill, 15 June 2004, p. 2.

19 ibid., p. 3.

20 DJV, *Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2005–14*, Port Macquarie, 24 August 2004, p. 3.

21 ibid., p. 4.

3.7 The AER’s considerations

As noted, the conversion provision in the code provides no express guidance on how the AER should exercise its discretion to convert a market network service to a prescribed service. In considering the general principles for conversion, therefore, the AER has had regard to the relevant code objectives, the history of the MNSP and conversion provisions, DJV’s submissions in support of its application, other parties’ submissions, and the ACCC’s approach in the Murraylink decision.

3.7.1 ‘Prescribed service’ approach

While the Murraylink decision is not binding on the AER, the AER considers that the approach set out in the Murraylink decision is useful for informing its consideration of the general principles for conversion. Further, DJV’s application and supporting submissions were based on the framework set out in the Murraylink decision.

The AER considers too that the history and intent of the conversion provision (discussed above) remain relevant to the consideration of conversion applications. When Directlink and other entrepreneurial interconnectors were built, MNSPs were encouraged despite being considered somewhat experimental—as acknowledged in the NECA working group’s review of arrangements for including MNSPs in the NEM. One means of encouraging these market based investments was to include the conversion provision to ensure market design risks did not inefficiently inhibit investment. Given the early encouragement offered to MNSPs and the implied assurance presented by the conversion provision, a decision now to set a relatively higher threshold for a conversion application may be inconsistent with the intention of the code’s MNSP and conversion provisions.

Accordingly, in determining whether a market network service is a prescribed service, the AER considers that a broad interpretation of the NECA working group’s intention should be applied. It is, therefore, appropriate for the AER to adopt the approach developed for the Murraylink decision—that is, to assess whether the network service is a prescribed service as defined in the code. (Chapter 4 discusses the application of this principle to Directlink.) The AER is mindful, however, of the public benefit argument raised in submissions, which is addressed below.

3.7.2 Public benefits and the broader regulatory framework

As outlined, the EUAA submitted that the Directlink conversion should be assessed on whether it provides a public benefit and that Directlink should be required to show changes in market conditions. Further, the EUAA and TXU submitted that conversion should be allowed only after a rigorous application of the regulatory test. The AER agrees and notes that the regulatory test considers the benefits to the market, and thereby the public benefit. That is, the regulatory test assesses whether an asset delivers net benefits to the market.

Further, in the context of a conversion application, clause 1.3(b)(4)—which states that a person entering the market should not be treated more or less favourably than a person already participating in the market—is particularly relevant to the AER. Application of the regulatory test ensures an MNSP will not accrue a material advantage from bypassing the code’s chapter 5 provisions. (Chapters 5–11 discuss the application of the regulatory test.) Nevertheless, the AER sees merit in further considering public benefit issues when deciding on conversion applications.

The ACCC considered that the principles and objectives of the transmission revenue regulatory regime (set out in chapter 6 of the code) offered guidance on whether Murraylink should have been converted to a prescribed service. Similarly, the AER notes that the various objectives set out in the code provide guidance on any public benefit issues relating to conversion applications. (These objectives are set out in section 3.2.) Various code provisions highlight the efficiency objectives of the NEM and the code, and the AER considers that its proposed approach to conversion (including application of the regulatory test) will promote these efficiency objectives. Specifically, the regulatory test assessment will determine the optimal project that delivers net benefits to the market. This, in turn, ensures transmission network users do not bear the cost of inefficient investment.

The regulatory test focuses on the increases in economic efficiency represented by increases in total welfare, by assessing benefits to market participants. This test is likely to ensure a fair and reasonable rate of return on efficient investment and an acceptable balancing of interests between a former MNSP and network users. In a properly functioning, competitive market, however, economic efficiency requires investors to bear the consequences of their investment decisions. Shielding investors from these consequences may lead to inefficient future investment decisions. An argument can thus be made that a relatively high threshold should be set for allowing conversion to a prescribed service. This argument would be consistent with the notion that the conversion provision is not intended to protect MNSPs from normal commercial risks.

The AER's proposed approach to conversion and its use of the regulatory test will result in a revenue entitlement adjusted to the appropriate level at the time of the conversion application, rather than guaranteeing a return on the original capital cost. This is consistent with ensuring an MNSP is not rewarded for inefficient investment and thereby shielded from normal commercial risks. Further, as noted in section 3.7.1, given the early encouragement offered to MNSPs and the apparent signals that conversion might be an option for MNSPs, a decision now to set a relatively higher threshold for a conversion application may be perceived as inconsistent with the intention of the MNSP and conversion provisions. This perception could create an environment of uncertainty. In this regard, the AER is seeking to provide certainty to maintain an environment that is conducive to efficient investment in accordance with the code and transmission regulatory regime objectives.

Regarding DJV's application, the transitional provisions provide for the decision to be made under the code (at 30 June 2005) and not the new National Electricity Law (NEL) and National Electricity Rules (NER). Accordingly, the AER is making its decision in accordance with the previous code provisions. Nonetheless, the new NEM objective is relevant to issues of public benefit. The NEM objective is:

> …to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and

> security of supply of electricity and the reliability, safety and security of the national electricity system.[22]

It clearly focuses on economic efficiency and aims to promote efficient use of existing services for the long term interests of electricity consumers. This appears to be consistent with, and informed by, the previous code objectives.

When considering the allocative efficiency implications of a conversion decision, it may be relevant in the short term to focus on marginal costs and ignore sunk costs. Because a converting asset is a sunk asset, disallowing a conversion application would not create a loss to electricity consumers. However, a consideration of dynamic efficiency prompts deliberation of how disallowing conversion would affect investment incentives in the future. Investment is susceptible to uncertainty, which may deter future investments in the long term. If, therefore, the conversion provision of the code is strictly implemented in the absence of these considerations—that is, if a high threshold is set for conversion—then it may be to the detriment of the long term interests of electricity consumers.

3.7.3 Other issues

The EUAA submitted that the ACCC should clearly outline a policy position disallowing 'switching' between regulated and unregulated transmission service provision.[23] The AER notes the 'safe harbour' provisions of the code preclude a prescribed service from switching back to a market network service. Clause 2.5.2(a) of the code provides:

> (3) the relevant network service must:
>
> (A) not have ever been a prescribed service …

3.8 Conclusion

The AER considers that a conversion application should be assessed in accordance with whether the service is a prescribed service as defined by the code. It is also of the view that public benefit issues and economic efficiency considerations provide further guidance on whether an MNSP should be converted. It considers that public benefit and economic efficiency issues are best accommodated through an application of the regulatory test framework.

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22 *National Electricity (South Australia) (New National Electricity Law) Amendment Act 2005*, Schedule, Part 1—Preliminary, clause 7—National electricity market objective.

23 EUAA, *Directlink—Application for Conversion to Regulated Status*, op. cit., p. 3.

4 Conversion of Directlink to a prescribed service

4.1 Introduction

In chapter 3, the AER concluded that it would have regard to whether a service meets the description of a 'prescribed service' under the National Electricity Code (the code). It also noted the public benefit issues raised in submissions. This chapter applies the principles set out in chapter 3 to DJV's application for conversion of Directlink to a prescribed service.

Given the code provisions, a prescribed service is a service that is not:

- a market network service, or
- excluded from the revenue cap under a more light handed regime imposed by the AER under clause 6.2.3(c), or
- found to be contestable under 6.2.4(f).

The remainder of this chapter sets out:

- DJV's application (sections 4.2)
- the AER's considerations (section 4.3)
- the AER's draft decision (section 4.4).

Submissions received from interested parties during the AER's assessment of DJV's application did not directly address the matter of whether Directlink exhibits the characteristics of a prescribed service.

4.2 DJV's application

4.2.1 Ceasing to be a market network service

DJV's application stated that:

> When, as contemplated under clause 2.5.2(c), Directlink's network service ceases to be classified as a market network service, it would not be a market network service.[24]

4.2.2 Light handed regime

DJV's application stated:

> In the Murraylink decision, the Commission has stated simply that it does not consider that sufficient competition in the market for network services would exist to warrant the application of a more light-handed regime. So Directlink's network service would not be excluded from a revenue cap under a more light-handed regime that might be imposed by the Commission because the Commission does not intend to impose such a regime.

[24] DJV, *Application for Conversion*, 22 September 2004, op, cit., p. 26.

4.2.3 Contestability of the service

DJV proposed that the AER consider the contestability of the service provided by Directlink with reference to two market definitions:

1. the market for transporting power between the Queensland and New South Wales (NSW) regions

2. the market for supporting the Gold Coast and far northern NSW networks.

Table 4.1 sets out DJV's assessment of whether effective competition characterises Directlink's service.

Table 4.1 DJV's assessment of the contestability of Directlink

Criteria for effective competition	Competition concern	Comment
Number of competing providers at present	Yes	▪ There are two interconnectors between NSW and Queensland, but one could exercise market power if the other were constrained, albeit that the DJV might dispute whether such market power is material. ▪ Directlink is the only existing provider of support to the Gold Coast and far northern NSW networks.
Degree of countervailing customer power	Yes	▪ Transmission customers have limited countervailing power.
Availability of substitutes	Yes	▪ Substitutes such as new generation, demand-side management or a market network service (that do not provide a prescribed service) are unlikely to be able to satisfy emerging limitations in the Gold Coast and far northern NSW networks.
Criteria for potential competition	**Competition concern**	**Comment**
Nature and extent of barriers to entry	Yes	▪ Transmission is characterised by economies of scale and scope, and a high proportion of (economically) sunk costs. ▪ Further entry of market network service providers is unlikely. ▪ Development costs for interconnectors are significant.

DJV submitted, based on its analysis, that Directlink's network service is not a contestable service. It concluded that Directlink's network service would satisfy all three limbs of the test for a prescribed service.[25]

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[25] ibid., pp. 27–8.

4.3 The AER's considerations

4.3.1 Ceasing to be a market network service

A final decision to allow conversion of Directlink is conditional on Directlink ceasing to be classified as a market network service by a specified date. The AER expects to be notified by DJV when Directlink ceases to be a market network service. Accordingly, Directlink would then be eligible to be determined to be a prescribed service.

4.3.2 Light handed regime

The AER does not consider that sufficient competition would exist to warrant the application of a more light-handed regime. Competition issues are discussed below.

4.3.3 Does Directlink provide a contestable service?

Regarding the third limb of the definition of a prescribed service, clause 6.2.4(f) of the code refers to services not reasonably expected to be offered on a contestable basis. In turn, chapter 10 of the code defines 'contestable' as:

> … a service which is permitted by the laws of the participating jurisdiction to be provided by more than one Network Service Provider as a contestable service or on a competitive basis.

This definition is not relevant to the current consideration because the relevant jurisdictions (NSW and Queensland) do not specify which services can be provided by more than one network service provider.

In the Murraylink decision, the ACCC referred to guidelines developed by the Victorian Essential Services Commission, the NSW Independent Pricing and Regulatory Tribunal and the Queensland Competition Authority for guidance on the meaning of contestability. The Essential Services Commission defined contestability as describing a market characterised by effective or potential competition, and the ACCC adopted this framework in assessing Murraylink. The AER agrees that this competition framework is appropriate for assessing the contestability of the service provided by Directlink.

Competition is typically considered in terms of the number of competing players, whereby a greater number of competitors means a more competitive market. Regardless of the number of competitors, however, a market with 'effective competition' means that a supplier has limited scope to wield market power and that regulation is unlikely to be necessary. Effective competition can occur when barriers to entry are low, close substitutes are available or customers have a significant degree of countervailing power. Similarly, a potentially competitive market is one in which firms do not exercise market power that might otherwise exist because there is a credible threat of potential competition from new entrants.

In considering whether Directlink is a contestable service, the AER needs to first define the market in which the service operates. It considers that the broad and narrow definitions proposed by DJV, of the market for Directlink's service, are appropriate for assessing the contestability of the service.

Transfer of power between Queensland and New South Wales

Number of competing providers

The only competing provider for the transfer of power between Queensland and NSW is the Queensland–NSW Interconnector (QNI). Directlink and QNI transfer electricity between Queensland and NSW at a rated capacity of 180 MW and above 1000 MW respectively. As discussed in chapter 8, Directlink and QNI both draw power from northern NSW to flow north into Queensland; consequently, there is no net increase in the transfer of power north due to the services of Directlink. Directlink thus increases the capacity for power flow only south into NSW.

The AER notes that the Heywood, Murraylink and QNI interconnectors are prescribed services even though there are two interconnectors between their respective regions. The presence of a single competitor does not necessarily indicate effective competition in the market: when one interconnector is constrained, the potential market power of the other may be enhanced.

Countervailing power

Countervailing power constitutes the ability of consumers to bypass a service through their consumption decisions. In the context of electricity, demand-side management would be a form of countervailing power. Demand-side management would need to occur, however, on a scale that is comparable to Directlink's rated capacity of 180 MW. Given the size of the market for the transfer of power between Queensland and NSW, countervailing power/demand-side management of this magnitude does not exist and seems unlikely to occur. For this reason, demand-side management does not provide an effective countervailing power.

Availability of substitutes

Generation is a potential substitute for the transfer of power between regions. A number of generation projects are planned for northern NSW. Given the proposed site and size of these generators, however, they are unlikely to be able to substitute for the transfer capacity of Directlink. Further, a generator does not provide technical services similar to those of an interconnector and Directlink in particular.

Market for network support to Gold Coast and the north coast of New South Wales

Number of competing providers

Directlink is located entirely within NSW between Terranora and Mullumbimby, but it connects the NSW and Queensland price regions in the National Electricity Market (NEM). The QNI is not located close enough to the areas serviced by Directlink to be a competitor or a substitute for network support to the Gold Coast and north coast of NSW. In terms of competing providers, therefore, none currently exists.

Countervailing power

As discussed, demand-side management can be a form of countervailing power. However, the far north (or north east) coast of NSW and Gold Coast is expected to experience demand growth at an average of 20 MW (or 11 per cent) per year until 2019–20. This level of growth is unlikely to be affected by demand-side management, which needs to occur on a sufficient scale that is comparable to Directlink's rated capacity of 180 MW. Demand-side management is also hampered by the low number of large industrial and commercial customers on the Gold Coast and in north east NSW who could actively participate in any voluntary load shedding scheme.

Availability of substitutes

Generation is an alternative to electricity supply and thus a substitute for network support. The AER is aware of a number of planned generation projects for the north coast of NSW. While of a smaller capacity than Directlink, they may be able to provide some network support to the local area. Again, however, this is unlikely to occur on a sufficient scale to provide a substitute for Directlink. Likewise, demand-side management can be a potential substitute, but the occurrence of demand-side management on a comparable level to Directlink's capacity is not a viable option for the Gold Coast and north coast of NSW.

The relevant question is whether it would be economic to develop another interconnector in this narrowly defined market. As noted below, the AER expects this would be unlikely.

Potential for competition

Under both the broad and narrow definitions of the market, the likelihood of new competitors entering the market is low. There appear to be high barriers to the development of another interconnector between the Queensland and NSW regions. A potential entrant in a transmission market typically faces entry barriers, including the incumbent operator's economies of scale, lumpy investment and, in some cases, the risk of not recovering the sunk costs of new entry (barriers to exit). Further, the minimum efficient scale of the market may preclude entry entirely. These factors mean that the potential for competition is limited.

On the Gold Coast and the north coast of NSW, the potential for entry depends on whether there is sufficient demand to support the development of a second interconnector and the cost involved. Based on forecasts of demand on the north coast of NSW, it is questionable whether a second interconnector in that area would be commercially viable, particularly given the high start-up costs.

Conclusion

There is insufficient effective or potential competition for the interstate transfer of power for Directlink to be considered a contestable service when a *broad* definition of the market for Directlink's service is adopted. This also implies that there is insufficient competition to warrant the application of a more light-handed regime.

While generation is a potential substitute for the network support services provided by Directlink under a *narrow* market definition, it is unlikely to occur on a sufficient scale to substitute for Directlink's services. Demand-side management can be a form of countervailing power, but the occurrence of demand-side management on a comparable level to Directlink's capacity is not a viable option. Consequently, the conditions for effective or potential competition are either weak or not present under a narrow market definition.

DJV's analysis against this competition framework is thus consistent with that of the AER. Directlink's network service cannot reasonably be expected to be offered on a contestable basis under either market definition. The AER considers, therefore, that Directlink satisfies each of the three limbs of the definition of a prescribed service.

4.3.4 Public benefits and the broader regulatory framework

As discussed in chapter 3, a consideration of public benefits in the context of the code and transmission regulatory regime objectives can provide further guidance in assessing a conversion application. The Energy Users Association of Australia (EUAA) submitted that the Directlink should be assessed on whether conversion would provide a public benefit in price and/or reliability, to justify the granting of the application. It was concerned that 'merchant links based on strong initial cash flows might be built only to see the well known vagaries of the NEM spot market destroy these, with the owner then making use of the option to convert to regulated status'.[26]

The EUAA also submitted that the AER should permit conversion only after a thorough analysis based on the regulatory test principles, ensuring customers benefit more from conversion than from Directlink remaining a merchant link or from the alternatives to Directlink. The AER has used the regulatory test to assess the net benefits to the market of alternative projects. It thus considers that it has accounted for the net market benefits. (Chapters 5–11 discuss the application of the regulatory test in detail.)

Moreover, the AER considers that the use of the regulatory test will ensure a fair and reasonable rate of return for DJV, based on an appropriate asset value. This process achieves a reasonable balancing of interests in accordance with the objectives of the transmission revenue regulatory regime.

4.4 The AER's draft decision

The AER's draft decision under clause 2.5.2(c) of the code is that Directlink's service will be a prescribed service from when it ceases to be classified as a market network service.

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[26] EUAA, loc. cit.

Part C – Application of regulatory test and establishing the asset value

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5 Framework for asset valuation

5.1 Introduction

Clause 2.5.2(c) of the National Electricity Code (the code), which is the conversion provision, states that once a service is determined to be a prescribed service:

> … the revenue cap or price cap of the relevant Network Service Provider may be adjusted in accordance with Chapter 6 to include to an appropriate extent the relevant network elements which provided those network services.

Accordingly, the AER is required to adjust the revenue cap for the relevant network service provide (NSP) in accordance with chapter 6 of the code. In setting a revenue cap for the 'converting' asset, the first step is to identify the method for determining an appropriate value for the regulated asset. In considering which method is appropriate for determining the value of Directlink's regulated asset base (RAB), the AER has had regard to:

- relevant provisions of the code, particularly those of chapter 6
- various asset valuation methods
- the ACCC's Murraylink decision.

The remainder of this chapter sets out:

- the code provisions (section 5.2)
- the asset valuation framework (section 5.3)
- the Murraylink decision (section 5.4)
- DJV's application (section 5.5)
- submissions (section 5.6)
- the AER's considerations (section 5.7)
- the conclusion (section 5.8).

5.2 Code provisions

Part B of chapter 6 of the code sets out the provisions governing the regulation of transmission revenue. The key provisions that guide the asset valuation decision include:

- the key transmission revenue regulatory principles and objectives in chapter 6 of the code, as set out in clauses 6.2.2 and 6.2.3
- the form of regulation, as set out in clause 6.2.4

- the intended purpose of clause 2.5.2(c)
- the market objectives in clause 1.3 of the code.

5.2.1 Guiding principles

Clause 6.2.3 of the code sets out the principles that guide the AER in regulating transmission revenues. Clause 6.2.3(d)(4) states that:

> (d) The regulatory regime to be administered by the ACCC must be consistent with the objectives outlined in clause 6.2.2 and must also have regard to the need to:
>
> ...
>
> (4) provide a fair and reasonable risk-adjusted cash flow rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment given efficient operating and maintenance practices on the part of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) where:
>
> (i) assets created at any time under a take or pay contract are valued in a manner consistent with the provisions of that contract;
>
> (ii) assets created at any time under a network augmentation determination made by NEMMCO under clause 5.6.5 are valued in a manner which is consistent with that determination;
>
> (iii) subject to clauses 6.2.3(d)(4)(i) and (ii), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction provided that the value of these existing assets must not exceed the deprival value of the assets and the ACCC may require the opening asset values to be independently verified through a process agreed to by the National Competition Commission;
>
> (iv) subject to clauses 6.2.3(d)(4)(i) and (ii), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the ACCC and in determining the basis of asset valuation to be used, the ACCC must have regard to:
>
> A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;
>
> B any subsequent decisions of the Council of Australian Governments; and
>
> C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2; and
>
> (v) benchmark returns to be established by the ACCC are to be consistent with the method of valuation of new assets and revaluation, if any, of existing assets and consistent with achievement of a commercial economic return on efficient investment;

Because Directlink is a 'new asset', it is to be valued on a basis determined by the AER. In doing so, the AER must have regard to the Council of Australian

Government's (COAG) 1994 agreement that deprival value is the preferred approach to valuing network assets.

5.2.2 Objectives of transmission revenue regulatory regime

Clause 6.2.3(4)(iv)(C) requires the AER to have regard to other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2. These objectives are:

(a) an efficient and cost-effective regulatory environment;

(b) an incentive-based regulatory regime which:

(1) provides an equitable allocation between Transmission Network Users and Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) of efficiency gains reasonably expected by the ACCC to be achievable by the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate); and

(2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment, given efficient operating and maintenance practices of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate);

(c) prevention of monopoly rent extraction by Transmission Network Owners and/or Transmission Network Service Providers (as appropriate);

(d) an environment which fosters an efficient level of investment within the transmission sector, and upstream and downstream of the transmission sector;

(e) an environment which fosters efficient operating and maintenance practices within the transmission sector;

(f) an environment which fosters efficient use of existing infrastructure;

(g) reasonable recognition of pre-existing policies of governments regarding transmission asset values, revenue paths and prices;

(h) promotion of competition in upstream and downstream markets and promotion of competition in the provision of network services where economically feasible;

(i) reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;

(j) reasonable certainty and consistency over time of the outcomes of regulatory processes, recognising the adaptive capacities of Code Participants in the provision and use of transmission network assets;

(k) reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of Transmission Network Owners and/or Transmission Network Service Providers (as appropriate), Transmission Network Users and the public interest as required of the ACCC under the provisions of Part IIIA of the Trade Practices Act.

5.2.3 Form of regulation

Clause 6.2.4 of the code sets out the prescribed form and mechanism of pricing regulation, and states that:

- economic regulation is to be of the consumer price index (CPI) – X form (or some incentive based variant)
- in applying this form of economic regulation, the AER must set a revenue cap for each TNSP for a regulatory control period of not less than five years
- revenue caps are to apply only to those services that the AER does not reasonably expect to be offered on a contestable basis.[27]

Clause 6.2.4(c) also provides that the AER, in setting a revenue cap for a TNSP, must account for the revenue requirements of the TNSP, with regard to (among other matters):

> (5) the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets subject to the provisions of clause 6.2.3(d)(4).

5.3 The asset valuation framework

5.3.1 The regulatory test

The code requires proponents of new network infrastructure to apply the regulatory test.[28] The regulatory test has two limbs: one relating to augmentations to meet service (reliability) standards and the other relating to new interconnectors or augmentation options. The test in each case is different.

In the case of augmentations to meet service standards, the augmentation that minimises the net present value (NPV) of the cost of meeting the service standards satisfies the test.

In all other cases, the test is satisfied by the project that maximises the NPV of market benefit, having regard to alternative projects and market development scenarios. This is the limb that is relevant to Directlink. In summary, the application of the regulatory test to a new network asset involves the following steps:

1. identify reasonable alternative projects
2. estimate the costs and benefits of each alternative project
3. identify the alternative that maximises the NPV of market benefits
4. build the optimal asset and set its regulated asset base (RAB) to the efficient cost of constructing the asset.

In circumstances where no asset has been constructed, the regulatory test identifies the optimal project having regard to alternative projects and market development scenarios. Once the optimal project is built, the cost of the project becomes the asset value. However, Directlink is already in service. Nevertheless, a regulatory test can be undertaken as if Directlink had not been constructed. Such an approach will

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27 National Electricity Code, clause 6.2.4(a), (b) and (f).

28 ibid., clause 5.6.6.

determine whether Directlink is the optimal project at the time of conversion or whether some other asset is preferable.

Estimation of market benefits and costs

The regulatory test provides additional details on:

- the estimation of market benefits
- the selection of market development scenarios.

Both market benefits and costs are measured from the perspective of National Electricity Market (NEM) participants. Market benefit is defined in the regulatory test as:

> … the total net benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios.[29]

Cost is defined in the regulatory test as:

> … the total cost of the augmentation to all those who produce, distribute or consume electricity in the National Electricity Market. Any requirements in notes 1 to 9, inclusive, on the methodology to be used to calculate the market benefit of a proposed augmentation should also be read as a requirement on the methodology to be used to calculate the cost of an augmentation.[30]

The regulatory test excludes from analysis the benefits and costs not associated with the electricity market and those that cannot be measured in financial terms. Further, it provides that the NPV calculations should be measured using a discount rate appropriate for a private enterprise investment in the electricity sector.

Section (1)(b) of the notes accompanying the regulatory test provides guidance on what should be included in the estimation of market benefits and costs. The recommended estimates include '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 value of energy to electricity consumers as reflected in the level of VoLL [value of lost load];
>
> iii. the efficient operating costs of competitively supplying energy to meet forecast demand from existing, committed and modelled projects including demand side and generation projects;
>
> iv. the capital costs of committed, anticipated and modelled projects including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;

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29 ACCC, *Regulatory Test for New Interconnectors and Network Augmentations*, Canberra, 15 December 1999, p. 21.

30 ibid., p. 21.

v. the cost of providing sufficient ancillary services to meet the forecast demand; and

vi. the capital and operating costs of other regulated network and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.

Sensitivity analysis

The regulatory test requires sensitivity analysis of the calculation of market benefits and costs, in terms of key input variables, to demonstrate the robustness of the benefits. It prescribes sensitivity analysis of the discount rate. It also prescribes the modelling of a range of reasonable alternative market development scenarios that incorporate:

- demand growth at relevant load centres
- alternative project commissioning dates
- potential generator investments and realistic operating regimes
- projects that have commenced construction and are expected to be commissioned within three years (committed projects)
- projects at an advanced stage of planning that are expected to be commissioned within five years (anticipated projects)
- projects that are likely to be commissioned in response to growing demand or as substitutes for existing generation (modelled projects).

The regulatory test states that modelled projects included in the market development scenarios should be developed using both a 'least cost market development' approach and a 'market driven market development' approach. The former approach includes projects with a positive net present value. The latter mimics the market process by:

> … 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 actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.[31]

Thus, the regulatory test also prescribes scenarios using:

- least cost planning
- market entry based on NEM prices reflecting short run marginal cost (SRMC) bidding behaviour
- market entry based on NEM prices approximating actual market bidding behaviour.

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31 ACCC, op. cit., *Regulatory Test for New Interconnectors and Network Augmentations*, p. 23.

The project that satisfies the regulatory test is the one that maximises the net market benefit in most (although not all) credible scenarios.

5.3.2 Optimised deprival value

Deprival value is defined in the code as:

> A value ascribed to assets which is the lower of economic value or optimised depreciated replacement value.[32]

As defined in the code, deprival value is equivalent to optimised deprival value (ODV) and is an accepted economic concept. It provides clear economic justification and links to public interest.

The purpose of an ODV valuation is to determine the minimum economic loss to a business if it was deprived of an asset and then took action to minimise that loss. If this was the case, the firm would have three options:

1. replace the asset with an identical asset
2. replace the asset with a different asset
3. not replace the asset.

Under the first option, ODV is the optimised depreciated replacement cost (ODRC) of the current asset. Under the second option, ODV is the ODRC of the different asset. In essence, if the asset is to be replaced, the ODV approach is equivalent to the ODRC method. The advantage of using ODV or ODRC is that it discourages inefficient investment because inefficient assets are revalued down to their optimised replacement cost.

The first two options of ODV asset valuation are equivalent to a regulatory test assessment. In applying a regulatory test to determine the augmentation that maximises the net present value of the market benefit at the time of the loss, a firm would decide to replace the asset with an identical asset or an alternative project. This equates to the asset with the lowest ODRC and leads to the same outcome, bearing in mind that the regulatory test has regard to a number of alternative projects, timings and market development scenarios.

Under the third option, ODV is the 'economic value' (EV) of the asset. EV applies when the asset is worth less than its ODRC. If the maximum revenue that the asset can earn, less the capital and operating expenditure, is insufficient to provide a normal rate of return on asset values at ODRC, then the firm would choose not to replace the asset. In the absence of options 1 or 2 being economically viable options, a firm would value the lost asset based on its EV. Valuing an asset at the minimum of its ODRC and EV avoids over-inflating the ODV of a firm's assets.

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32 National Electricity Code, chapter 10, 'Glossary'—see 'deprival value'. The code defines neither 'economic value' nor 'optimised depreciated replacement value'.

Economic value can be defined as 'the greater of disposal or salvage value (that is, net realisable value), or its value to users…' (that is, economic benefit).[33] An asset's value to users can be interpreted as the net present value of the future market benefits it provides in its lifetime.

For the purposes of the Murraylink decision, Saha Energy International Ltd. stated that they interpreted the Murraylink Transmission Company's (MTC) proposed approach to asset valuation as an economic value approach. It stated that MTC's proposed regulated asset value would be defined by the estimated value of market benefits.[34]

In the absence of any alternative project maximising the net present value of the market benefits at the time of the loss, the firm would presumably value the lost asset at its EV.

5.3.3 Optimised depreciated replacement cost

The requirement of clause 6.2.3(d)(4)(iv)(A) to consider deprival value when valuing assets suggests that ODRC is an appropriate alternative valuation method. The ACCC endorsed ODRC as its preferred valuation method in the *Draft Statement of Principles of the Regulation of Transmission Revenue*.[35] It stated that ODRC is consistent with the requirements of Part B of chapter 6 of the code. The ACCC's *Statement of Principles for the Regulation of Electricity Transmission Revenues—Background Paper* (dated 8 December 2004) confirmed this preference for the initial valuation of a regulated asset.[36]

An ODRC valuation is employed where an asset is replaced, either with an identical or different asset. ODRC is the replacement cost of the existing network or system fixed assets that have been optimised from an engineering standpoint and then depreciated according to age. It measures the cost of replicating the system fixed assets in the most efficient way, given the required (or current) level of service.[37]

In the DRP the ACCC defined ODRC as:

> … the sum of the depreciated cost of assets that would be used if the system were notionally reconfigured so as to minimise the forward looking costs of service delivery.[38]

The ACCC considered the determination of ODRC involves three stages:

1. determining the optimal configuration and sizing of transmission assets

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33 New Zealand Commerce Commission, *Review of Asset Valuation Methodology: Electricity Lines Business' System Fixed Costs*, Discussion paper, October 2002.

34 Saha Energy International Ltd., *Review of the Murraylink Transmission Company Pty Ltd's Application of the Regulatory Test: Final Report*, February 2003, pp. 6-7.

35 ACCC, *Draft Statement of Principles of the Regulation of Transmission Revenues*, Canberra, 27 May 1999, pp. xi, 39–49.

36 id., *Statement of Principles for the Regulation of Electricity Transmission Revenues—Background Paper*, Canberra, 2004, pp. 37–9.

37 Ministry of Economic Development, *Discussion Paper on the Requirement for Economic Valuations Under the Electrivity ODV Handbook*, Wellington, April 2000, p. 4.

38 id., *Draft Statement of Principles*, op. cit., pp. xi, 39.

2. establishing a modern engineering equivalent for each asset in the optimised system and a standard replacement cost

3. depreciating those assets using the standard economic life of each asset together with an estimate of the remaining life of each asset.[39]

It rejected, however, the use of ODRC in its Murraylink decision because this approach may provide for a different valuation than would an application of the regulatory test. Such a valuation would not satisfy the objective in clause 1.3(b)(4) of treating entrants more or less favourably than those already participating in the market. The ACCC considered that the most effective way of ensuring consistent treatment of a person seeking to construct a new large network asset and a market network service provider (MNSP) seeking to convert is to apply the same test in determining the asset value of the prescribed service—namely, the regulatory test.

The ACCC stated that the regulatory test may require the consideration of a wider range of alternatives that assume different levels of service. The code requires a proponent of a new large network asset to apply the regulatory test and to consider 'reasonable network and non-network alternatives' that include (but are not limited to) interconnectors, generation options, demand-side options, market network service options and options involving other transmission and distribution networks. While the regulatory test is consistent with ODV and ODRC, it provides a more rigorous framework for valuation by taking into account a broader range of options which might provide a different level of service.

It could be argued that ODRC does not normally involve optimisation based on alternatives that might supply a different level of service. While it is not certain whether ODRC requires such a limitation, the application of ODRC could result in outcomes that are inconsistent with the regulatory test.

5.3.4 The Allen Consulting Group's proposed alternative

The Allen Consulting Group (ACG) proposed that application of the regulatory test, rather than adopting the capital and operating costs of the project that maximises the NPV of market benefits in most credible scenarios, should adjust the asset value of the converting MNSP so net market benefits (NMB) generated by the existing asset are equal to those of the optimal project.[40] That is, its proposed approach compares and adjusts for different level of benefits between an alternative project and the existing asset where an alternative project satisfies the regulatory test.The ACG proposal can be expressed as:

$NMB_{permitted} = NMB_{optimal}$[41]

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[39] ibid., pp. xi, 42.

[40] The Allen Consulting Group, *Conversion of a Market Network Service to a Prescribed Service—Setting the Regulatory Asset Value*, Sydney, October 2004, p. 5.

[41] 'NMB' refers to the net present value of market benefits—that is, the present value of gross market benefits less the present value of the lifecycle capital and operating costs; the subscript 'permitted' refers to revenues or costs permitted by the regulator in establishing the maximum

This formula can be broken down and re-arranged to derive the following formula for determining the RAB of the converting asset:

$Cost_{permitted} = Cost_{optimal} - (GMB_{optimal} - GMB_{converting\ asset})$ [42, 43]

The ACG concluded that the costs used to establish the asset value should be those of the optimal project, but adjusted to account for the difference between the gross market benefits (GMB) of the optimal project and those of the existing project (the MNSP). In practice, the difference between the GMB of the converting asset and the optimal asset would be deducted from the capital cost embodied in the RAB because the present value of operating expenses is returned through the maximum allowed revenue.

Another way of saying this is that the capital and operating costs of the MNSP are used to determine the maximum allowed revenue with a deduction from the converting MNSP's RAB for the difference between the NMBs of the optimal project and those of the MNSP:

$Cost_{permitted} = Cost_{converting\ asset} - (NMB_{optimal} - NMB_{converting\ asset})$[44]

The ACG argued the following advantages of its proposed approach:

- The economic welfare of market participants (as measured by the net market benefits generated by the converting asset) is the same after conversion as if the optimal asset had been built.
- The owner of the converting asset incurs a financial loss to the extent that the original investment was inefficient, as measured by the difference between the net market benefits of the MNSP and the optimal project.
- Its method selects the same optimal project as would a conventional application of the regulatory test when the alternative projects provide the same level of benefits.
- It eliminates the incentive to bypass the regulatory test by constructing a suboptimally small asset to accrue a windfall gain from a higher cost optimal project.
- It generates outcomes consistent with an ODRC valuation.

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allowed revenue; and the subscript 'optimal' denotes benefits or costs associated with the optimal project.

42 'Cost' refers to the present value of efficient capital and operating costs; 'GMB' refers to the present value of gross market benefits; and the subscript 'converting asset' denotes benefits or costs associated with the MNSP.

43 $NMB_{converting\ asset} = NMB_{optimal}$
$GMB_{converting\ asset} - Cost_{converting\ asset} = GMB_{optimal} - Cost_{optimal}$

44 $Cost_{converting\ asset} = -(GMB_{optimal} - Cost_{optimal}) + GMB_{converting\ asset}$
$Cost_{converting\ asset} = GMB_{converting\ asset} - NMB_{optimal}$
$Cost_{converting\ asset} = (Cost_{converting\ asset} + NMB_{converting\ asset}) - NMB_{optimal}$

- It reduces the variance of the cost base derived from applying the regulatory test, because the cost base of the MNSP is used, with the only adjustment being the difference between the NMBs of the optimal project and the MNSP.

5.4 The Murraylink decision

The ACCC has considered one other application for conversion under clause 2.5.2(c), relating to the Murraylink interconnector. DJV's application has adopted the framework used by the ACCC in that decision. The ACCC applied the regulatory test which identified an optimal alternative project. The cost of that project was used to determine Murraylink's opening asset value (or RAB). The Murraylink decision interpreted the application of the regulatory test for an MNSP's conversion to involve:

1. identifying alternative projects that are reasonable substitutes to the project in question

2. calculating the present value of net benefits of the alternative projects under a range of reasonable market development scenarios

3. adopting the capital and operating costs of the alternative project that maximises the NPV of market benefits in most credible scenarios (that is, the optimal project).

The outcome of applying the regulatory test in this manner is to set the capital (RAB) and operating costs of the converting MNSP to those of the optimal project. This can be expressed as:

$\text{Cost}_{\text{permitted}} = \text{Cost}_{\text{optimal}}$

5.4.1 Rationale for applying the regulatory test

The ACCC considered that applying the regulatory test ensured an MNSP seeking conversion was treated in the same manner as a proponent seeking approval to construct a new large network asset for the provision of prescribed services. It was concerned that an MNSP could use the conversion provision to bypass the provisions of the code that would ordinarily apply to the construction of a new interconnector. If the regulatory test were not applied, then the market objective of ensuring market entrants not be treated more or less favourably than those already participating in the market would not be met.

This concern was expressed in the ACCC's authorisation of code changes for the conversion provision. In that determination, the ACCC stated:

> Interested parties raise the issue of such a process enabling MNSPs to bypass the regulatory test that applies to new prescribed network services such as interconnectors, augmentations or augmentation options. The process for establishing a new market network service is seen by some interested parties as administratively more simple than the process for establishing a new regulated interconnector. The key concern appears to be that conversion from market to prescribed network services offers an administratively simple path to construct network services, which could then be allocated a regulated revenue stream, rather than remaining subject to market risks.

> Clause 2.5.2(c) sets out an arrangement where the relevant regulator has a high degree of discretion regarding the classification of a network service as a prescribed service and determining the appropriate extent that a revenue cap or price cap is adjusted to reflect the newly prescribed services.
>
> The Commission considers that as the nominated regulator for transmission assets, the Commission will generally be the relevant regulator exercising its discretion in regard to conversion of market network service to prescribed network services. Where the Commission decides a network service may be a prescribed network service, an NSP will require a revenue stream to be determined for that service. The Commission will consider the prudence of the network service at the time the conversion to a prescribed service occurs, rather than consider any earlier investment decisions. As such the investor would bear the risk of the Commission optimising down the value of the assets—with the consequence of reduced revenue streams, at the time it converted to regulated status and at each regulatory review into the future.[45]

5.4.2 Consistency with chapter 6 of the code

In its Murraylink decision, the ACCC stated that use of the regulatory test was consistent with the requirements of chapter 6 of the code.[46] It was required to promulgate the regulatory test in a manner consistent with the method of asset valuation that the ACCC determined for regulating revenues.[47] It considered that the regulatory test seeks to determine an asset value based on the optimal configuration and sizing of an asset. This approach is consistent with the objectives in clause 6.2.2 of the code, which emphasise efficiency. The ACCC stated that the regulatory test has regard to COAG's preference for deprival value.

5.5 DJV's application

Consistent with the Murraylink decision, DJV's revised application (dated 22 September 2004) applied the regulatory test which identified an alternative project to determine the RAB for Directlink. On 3 November 2004, however, DJV submitted an ACG report that proposed that the ACCC adopt a variation of the regulatory test in exercising its discretion to determine the RAB.

5.6 Submissions

Both the EUAA and TXU expressed concern with the application of the regulatory test for assets that have already been built. TXU stated that applying the regulatory test to an asset that has already been built leads to ambiguous outcomes, while the EUAA argued that the AER should permit conversion only after rigorously applying the regulatory test principles. It quoted the National Economic Research Associates' (NERA) submission to the Murraylink application, arguing that the AER should:

> … apply the regulatory test to the project specified as 'the change in status of Murraylink from a market network service provider (MNSP) to a regulated interconnector'. … The maximum regulated cost that could be set for Murraylink would then be the lowest of the

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45 ACCC, *Applications for Authorisation: Amendments to the National Electricity Code—Network Pricing and Market Network Service Providers*, Canberra, 21 September 2001, p. 138.

46 ACCC, *Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue*, Canberra, 1 October 2003, p. 41–3.

47 National Electricity Code, clause 5.6.5A(b).

capex cost plus lifecycle opex costs for Murraylink; or the expected revenue for Murraylink if it continued to act as an MNSP plus the net benefit to the market of Murraylink changing its status from an MNSP to a regulated interconnector.[48]

The EUAA also argued that it was important to recognise that Directlink is a sunk asset and that conversion to regulated status is worth somewhere between its scrap value and the replacement cost of the least cost option providing similar benefits. It stated that Directlink would presumably remain in operation, even if its application for conversion is rejected, so long as it covered its operating and maintenance expenditure.

Other submissions did not directly comment on the use and application of the regulatory test to determine an asset value.

5.7 The AER's considerations

5.7.1 Asset valuation framework

In considering the appropriate framework to determine the asset value of Directlink, the AER has had regard to the guidance provided by the code, the approach adopted in the Murraylink decision (that is, the application of the regulatory test), and the ACG's proposed approach. The AER has also considered a number of asset valuation methodologies including ODV and ODRC.

The AER notes that both the ODV method of asset valuation and the regulatory test framework seek to identify and evaluate the optimal configuration and sizing of the asset to achieve a particular level of service. The asset value is set by reference to the cost of the optimal project under both approaches andboth discourage inefficient investment through inefficient assets being revalued down to their optimised replacement cost. The main difference between the two approaches is that the regulatory test may consider a wider range of alternatives that provide similar, but not identical levels of service, and a number of market scenarios.

The application of the regulatory test to Directlink would help ensure consistency between the AER's consideration of DJV's application and the approval of other forms of regulated investments. That is, applying the regulatory test to converting network services would prevent an MNSP from being able to bypass the provisions in chapter 5 of the code. It also has regard to COAG's preference for using deprival value for asset valuation, outlined in clause 6.2.3(d)(iv)(A) of the code, because the regulatory test framework provides an outcome that is consistent with the ODV method. For these reasons, the AER proposes to apply the regulatory test to Directlink to identify an optimal project. The cost of this optimal project can then be used to determine Directlink's asset value.

Rather than considering the ACG's proposed approach in the abstract, the AER will consider the proposal further in applying the regulatory test.

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48 EUAA, op. cit., p. 4.

The EUAA advocated using an incremental benefits approach to asset valuation, based on the approach suggested by NERA in the Murraylink decision. In the Murraylink decision, the ACCC stated that the incremental benefits approach is not appropriate for achieving symmetry between the processes applied to MNSPs who seek conversion and the treatment of transmission augmentation proposals made under chapter 5 of the code. The ACCC considered, because the code includes the conversion provision, that a measurement of the market benefits of an interconnector should be aligned to the intention of the regulatory test as closely as possible.[49]

The EUAA also argued that Directlink as a sunk asset should be valued between its scrap value and the replacement cost of the least cost option providing similar benefits. This appears to be similar to the ODV method. The AER agrees that scrap value provides a useful lower limit to asset valuation. However, caution should be exercised, so as not to value the asset such that the return on the investment is below the opportunity cost of capital. This may not provide incentives for future investment, in conflict with the requirements of chapter 6 of the code (particularly clause 6.2.2, which outlines the AER's requirement to foster an efficient level of investment in transmission infrastructure and to balance the interests of network owners, network users and the public).

The AER also considers that the replacement cost of the least cost option provides a useful upper limit to asset valuation. It measures the cost of replicating the assets in the most efficient way, thus discouraging inefficient investment that is not in the interests of network users and the public. In summary, the AER considers that a reasonable balance is to adopt a valuation method that provides a value for the asset somewhere between the two bounds. This is consistent with clause 6.2.4(c)(5), which states that the AER must provide a fair and reasonable risk adjusted cash flow rate of return on efficient investment, including sunk assets.

The AER agrees with comments by the EUAA and TXU that a rigorous application of the regulatory test is required. It has done so by:

- identifying and selecting alternative projects that are reasonably comparable to Directlink
- estimating the present value of the network deferral benefits of Directlink and its alternative projects
- estimating the present value of the interregional benefits of Directlink and its alternative projects
- estimating the costs of Directlink and its alternative projects
- considering market development scenarios and performing a sensitivity analysis for Directlink and its alternative projects
- ranking Directlink and its alternative projects.

Chapters 6–11 outline these steps.

49 ACCC, *Murraylink Transmission Company Application*, op. cit., p. 24.

5.7.2 Version of the regulatory test

The code requires the ACCC to promulgate the regulatory test.[50] The ACCC first released the regulatory test in 1999.[51] In its original application (dated 6 May 2004), DJV adopted the 1999 regulatory test. The ACCC has since reviewed the regulatory test and, in August 2004, released a revised version.[52] The 2004 version is ostensibly the same as the 1999 version and entails the above steps, but it is more prescriptive in detailing how the test is to be applied and it expressly allows for consideration of competition benefits. DJV's revised application does not consider competition benefits, so the differences between the 1999 and 2004 test versions are minimal in terms of the AER's consideration of DJV's application.

The 2004 version of the regulatory test was already in operation when DJV lodged its revised application. Exceptions are made, however, for circumstances where applicants involved in the regulatory test process have already undertaken analysis or consultation.[53] While applications for conversion to prescribed services are not one of the listed processes, DJV had undertaken analysis based on the 1999 test version, before publication of the 2004 version.

DJV stated that it does not perceive much difference between the two versions of the regulatory test and that it is flexible about which is adopted. The AER considers that it is appropriate to evaluate DJV's application against the 1999 version of the regulatory test (as contained in appendix C).

5.8 Conclusion

The application of the regulatory test framework to Directlink is justified by the need to ensure consistency between an MNSP seeking to convert and a proponent seeking approvalto construct a new large network asset. The outcomes of a regulatory test assessment are consistent with the requirements and objectives of chapter 6 of the code, and with COAG's preference for a deprival value approach to asset valuation.

The AER will apply the 1999 version of the regulatory test to identify an optimal project. The following chapters apply the regulatory test by:

- identifying and selecting alternative projects that are reasonably comparable to Directlink (chapter 6)
- estimating the present value of the network deferral benefits of Directlink and its alternative projects (chapter 7)
- estimating the present value of the interregional benefits of Directlink and its alternative projects (chapter 8)
- estimating the total costs of Directlink and its alternative projects (chapter 9)

50 National Electricity Code, clauses 5.6.6(b) and (h)
51 ACCC, *Regulatory Test for New Interconnectors and Network Augmentations*, Canberra, 1999.
52 id., *Review of the Regulatory Test for Network Augmentations*, Canberra, 2004.
53 ibid., p. 74, para. 17.

- considering market development scenarios and performing a sensitivity analysis for Directlink and its alternative projects (chapter 10)
- ranking Directlink and its alternative projects (chapter 11).

6 Selection of alternative projects

6.1 Introduction

The National Electricity Code requires a proponent of new large network assets to apply the regulatory test and to consider 'reasonable network and non-network alternatives' that include (but are not limited to) interconnectors, generation options, demand-side options, market network service options and options involving other transmission and distribution networks.[54] The regulatory test states that a new interconnector or augmentation option satisfies the test if it maximises the net present value (NPV) of the market benefit having regard to alternative projects (among other matters).

In circumstances where no asset has been constructed, the regulatory test identifies the optimal alternative project. In the current application of the regulatory test, this is not the case because Directlink is already in service. Nevertheless, a regulatory test can be undertaken as if Directlink had not been constructed. Such an approach will determine whether Directlink is the optimal project at the time of conversion or whether some other asset is preferable. It is still necessary to identify all reasonable alternative projects that could be constructed to address the emerging constraints in northern New South Wales (NSW) and south east Queensland.

This chapter considers the process for selecting alternative projects and sets out:

- the DJV's application (section 6.2)
- submissions and the consultancy report (section 6.3)
- the AER's considerations (section 6.4)
- the conclusion (section 6.5).

6.2 DJV's application

DJV engaged BRW to select, cost and assess alternative projects for the purpose of applying the regulatory test to Directlink.[55] BRW identified and assessed seven possible alternative projects:

- alternative 0—the existing Directlink project, which consists of three first generation high voltage direct current (HVDC) Light underground links between Bungalora and Mullumbimby, each with a capacity of 60 MW (that is, a capacity of 180 MW), together with an AC overhead cable between Terranora and Bungalora. Directlink provides both active and reactive support

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54 National Electricity Code, clause 5.6.6(b).

55 BRW, *Directlink: Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*, 22 September 2004, pp. ii, 4.

- alternative 1—a modern HVDC Light link with modified construction between Mullumbimby and Terranora, with 180 MW capacity, active and reactive support, protection and control systems, and underground cable construction
- alternative 2—a conventional HVDC link between Mullumbimby and Terranora, with 180 MW capacity, synchronous condensers, active and reactive support, protection and control systems, and overhead construction with partial underground cable construction
- alternative 3—a 132 kilovolt (kV) high voltage alternating current (AC) link between Mullumbimby and Terranora, with 180 MW capacity and a 132/110 kV phase shifting transformer, capacitors at each end, protection and control systems, and overhead construction with partial underground cable construction
- alternative 4—a high voltage AC link between Mullumbimby and Terranora with 250 MW capacity along with a conventional 132/110 kV auto-transformer, capacitors at each end, protection and control systems, and overhead construction with partial underground cable construction
- alternative 5—high voltage AC network augmentations in northern NSW and on the Gold Coast to address emerging network limitations in those areas due to load growth
- alternative 6—approximately 180 MW of embedded generation in each of the Gold Coast and the far north east of NSW, and demand management programs in addition to generation and demand management programs already anticipated.[56]

BRW considered that alternatives 4 and 6 are not reasonable for the purposes of the regulatory test. It considered that alternative 4 would not provide adequate levels of network support and offers no network augmentation deferral benefits. In addition, it concluded that alternative 6 is neither technically nor economically feasible, on the basis of not being of sufficient size to make any impact on the load growth.

BRW described alternative 5 as consisting of:

> … the reliability augmentations similar to those which Powerlink and TransGrid would have built as the first augmentations to alleviate the network constraints that will emerge in the Gold Coast and far north coast of NSW areas from around 2005. BRW has confirmed that these projects would have been required to support the respective transmission networks in the absence of Directlink providing network support over the planning period.
>
> BRW has identified that Directlink and its alternative projects (except for Alternative 4) could defer these reliability augmentations as set out in section 4. However, the Queensland and NSW reliability augmentations represent an alternative project in their own right.[57]

BRW went on to state that:

> Alternative 5 may be deferred by Directlink or other alternative projects to varying extents. On this basis, Alternative 5 is used in the set of projects that Directlink or the other alternative projects may defer when calculating the deferral benefit streams.[58]

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56 ibid., pp. 37–41.
57 ibid., p. 29.

It stated that alternative 5 does not provide any interconnection between the Queensland and NSW networks. But because alternative 5 addresses transmission constraints in the far north east of NSW and on the Gold Coast, BRW concluded that it is a reasonable alternative for the purposes of the regulatory test.

DJV stated that:

> Based on currently available information, BRW found that Alternative 5 be is [sic] the same project that Powerlink and TransGrid would pursue to meet their reliability obligations if Directlink was not in place.
>
> For the purposes of this application of the Regulatory Test, Alternative 5 as the default reliability augmentations has been taken to be the baseline project—that is, the project with which the other alternative projects and their market benefits are compared.[59]

6.3 Submissions and the consultancy report

The ACCC engaged Parsons Brinckerhoff Associates (PB Associates) to review the alternative projects proposed by BRW. PB Associates considered that DJV had correctly identified the alternatives available to provide network support equivalent to that offered by Directlink.[60] It did not identify any other credible alternatives.

PB Associates supported DJV's view that the DC interconnectors (Directlink, and alternatives 1 and 2) are reasonable alternative projects for the purposes of applying the regulatory test. It stated that alternative 3:

> … would present some operational difficulties in practice. The duty placed on the phase shifting transformer (PST) through the requirement to constantly monitor a number of critical network conditions and continually vary the operation of the PST accordingly, makes this alternative operationally challenging.
>
> Whilst PB Associates would not have advocated a PST based solution requiring greater phase angles, we recommend that Alternative 3, as described, does represent a technically possible alternative to Directlink and should therefore be included.[61]

PB Associates stated that alternative 4 has significant limitations, being a traditional AC link effectively operating in parallel with an interconnector (that is, the Queensland–NSW Interconnector, or QNI) of significantly higher rating. It agreed with BRW that alternative 4 is likely to offer little network support and is not a credible alternative to Directlink.

PB Associates stated that alternative 5 is likely to proceed in the future to provide a long term solution to supply requirements for this region. In its report, it referred to alternative 5 as a reference case and 'not strictly an alternative' because it provides 'considerably greater capacity that that offered by Directlink'. PB Associates stated:

> This Alternative is the only foreseeable option … that will provide secure electricity supply to the region in the medium and longer term. All other alternatives defer some, or all, of

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58 ibid., p. 32.
59 DJV, *Application for Conversion*, 22 September 2005 , op. cit., p. 40.
60 PB Associates, *Review of Directlink Conversion Application: Final Report*, Port Macquarie, November 2004, pp. 3, 59.
61 ibid., p. 58.

> these augmentations for varying periods but cannot (in isolation) provide the requisite levels of security to cater for growth in both electricity demand and customer numbers in the Gold Coast/Tweed region in the medium to long term.[62]

In its response to PB Associates' report, DJV reaffirmed that it does not consider alternative 4 to be a reasonable alternative and that alternative 3 has technical shortcomings. It disagreed, however, with PB Associates' classification of alternative 5 as a reference case.[63] DJV stated that:

> BRW and PB Associates have clearly established that a need exists for network augmentations in New South Wales and Queensland to enable TransGrid and Powerlink to satisfy their network reliability obligations. Alternative 5 represents a set of network augmentations that would need to be in place in the absence of Directlink's other alternative projects (including Alternative 0, Directlink itself) to satisfy network reliability standards in Queensland and NSW. That is, Alternative 5 is clearly an alternative project from which TNSPs [transmission network service providers] may choose to satisfy the reliability needs in Queensland and New South Wales in the same way that they may choose from Directlink's other alternative projects.
>
> PB Associates present Alternative 3 as an alternative project even though it provides substantially less capacity and less market benefits than Directlink.[64]

It went on to state that:

> BRW's Alternative 5 provides substantial gross market benefits to the same regions and nodes as Directlink, arguably more than Alternative 3, which PB Associates agrees is an alternative project to Directlink.[65]

The Energy Users Association of Australia (EUAA) stated that DJV should be required to apply the regulatory test to alternative projects that offer a similar level of service rather than purely technical benefits. While demand management and embedded generation alternatives were raised, DJV's application did not evaluate the benefits.

6.4 The AER's considerations

In its Murraylink decision, the ACCC stated that alternative projects were required to provide not a level of service identical to that of Murraylink, but a level of similarity.[66] It considered that most of the benefits from Murraylink arose from its power transfer capability into South Australia. It refused, however, to consider augmentations that provided for electricity flows between regions of the National Electricity Market (NEM) but did not support the local regions served by Murraylink. It considered that proposed alternatives, to be sufficiently similar, had to be able to both deliver both interregional power transfers and support regions served by the interconnector.

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62 ibid., p. 20.
63 DJV, *Submission in Response to PB Associates Report of 26 November 2004*, 14 January 2004, pp. 34–5.
64 ibid., p. 21.
65 ibid.
66 ACCC, *Murraylink Transmission Company Application*, op. cit., p. 51–2.

In the case of Directlink, the benefits will arise from both its ability to transfer power between NSW and Queensland, and its ability to provide reliable support to networks in the far north coast of NSW and the Gold Coast/Tweed area. It is appropriate, therefore, for the AER to limit its consideration of reasonable alternative projects to those that similarly provide additional power transfer as well as network support.

The AER has considered the views of BRW and PB Associates regarding reasonable alternatives. It appears reasonable to conclude that alternatives 1, 2, and 3 have the requisite level of similarity to Directlink to be considered as alternative projects under the regulatory test. These alternatives:

- potentially defer the augmentations described by BRW as alternative 5 for varying periods
- allow for the flow of electricity between regions of the NEM to different extents and with differing levels of controllability.

The AER notes that Directlink, alternatives 1 and 2 provide the same level of service as each other and therefore the same benefits to the market. The only difference between these projects is the technology used and therefore the cost.

The AER will not consider alternatives 4 and 6 as being credible alternative projects to Directlink, given their technical and/or economic limitations.

DJV argued that alternative 5 should be treated as an alternative project while PB stated that it should be treated as the reference case. In the absence of Directlink, alternative 5 would be constructed by Powerlink and TransGrid to address system reliability constraints. Directlink or some other alternative project may be able to defer alternative 5 for a period of time, but eventually each of the augmentations in alternative 5 will be needed.

The first limb of the regulatory test inquires about the least cost augmentation to meet service (reliability) standards. In this circumstance, it would assess whether it is more efficient to proceed straight to alternative 5 or whether it would be optimal to defer alternative 5 for some time by relying on Directlink (or some other alternative project). That is, it would compare the present values of the following two capital cashflow streams:

- alternative 5 now
- Directlink (or another project) now, and alternative 5 later.

The second limb of the regulatory test, which is relevant to the current application, makes a different comparison. It identifies the alternative project that maximises the net present value of market benefits, where market benefits include network deferral and interregional benefits. The estimation of net market benefits requires a basis for comparison. That is, the AER must apply a ‘with’ and ‘without’ test. For example, in the case of Directlink it is necessary to compare the benefits with Directlink in place to the benefits without Directlink.

The second limb of the regulatory test compares the following net market benefit streams:

Net benefit of project	=	gross market benefits – gross costs
	=	(deferral of alternative 5 + interregional benefits of project) – cost of project

This comparison requires the establishment of a 'reference' or 'base' case. Alternative 5 is that reference case because it would be constructed under the first limb of the regulatory test if there was no deferral benefit. That is, alternative 5 would be constructed because it is the least cost method of meeting reliability standards. If the AER was to accept alternative 5 as an alternative project, it would be an alternative project that would defer itself from construction. However, alternative 5 does not defer augmentations in NSW and Queensland because it is the required augmentations. The AER will treat the augmentations associated with alternative 5 as the reference case for the regulatory test.

6.5 Conclusion

The AER will consider the following alternative projects for the regulatory test assessment: Directlink, alternative 1, alternative 2 and alternative 3. It will also consider alternative 5 as the reference case.

7 Network augmentation deferral benefits

7.1 Introduction

In its revised application (dated 22 September 2004), DJV identified two categories of market benefits:

1. benefits associated with deferral of transmission network augmentations

2. benefits associated with interregional power flows.[67]

This chapter contains the AER's considerations of the benefits of deferring transmission network augmentations. Directlink not only provides interconnection between regions in the NEM, but may also provide electricity or network support to the local areas to which it is connected. Provision of such support in one region depends on capacity being available in the network of the other region when the support is required. This network support may allow transmission network service providers (TNSPs) to meet their reliability obligations for a local area and thus defer network augmentations required to address that area's emerging constraints. Consequently, the savings in capital and operating expenditures from deferring network augmentations are a benefit to market participants within the NEM (see paragraph (1)(b)(iv) of the regulatory test).

The remainder of this chapter sets out:

- the background (section 7.2)
- the 'without Directlink' case (that is, the reference case) (section 7.3)
- the 'with Directlink' case (section 7.4)
- the 'with alternative projects' case (section 7.5).

7.2 Background

The transmission network augmentations that Directlink can defer, as proposed by DJV, are:

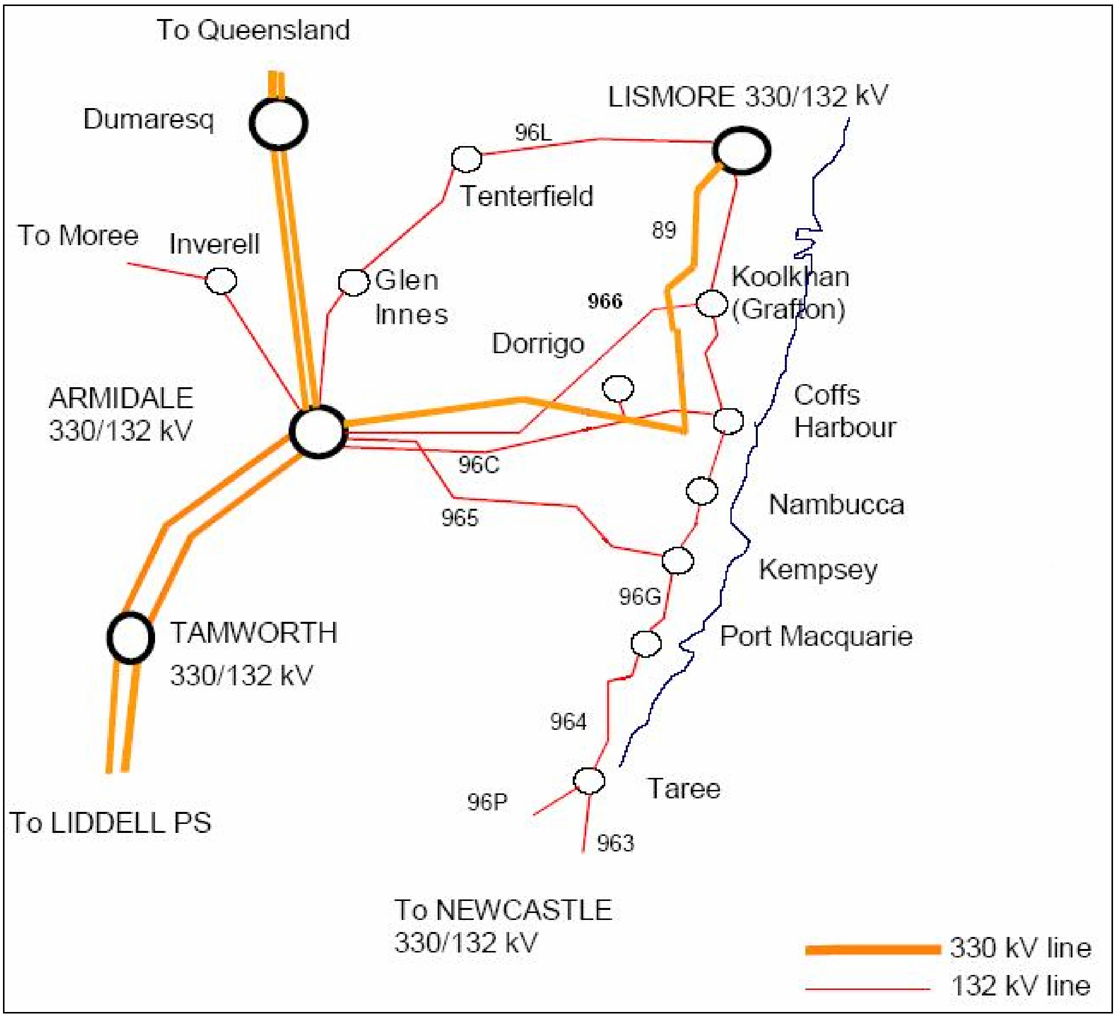
- a new 275 kilovolt (kV) Greenbank switchyard and a new double circuit 275 kV line linking the Greenbank and Molendinar substations
- an uprating of the existing 132 kV line from Armidale to Koolkhan
- a new 330 kV line from Dumaresq to Lismore
- back-up supply to Tenterfield, via a new 66 kV line from Emmaville to Tenterfield or a 330/132 kV substation at Tenterfield

67 DJV, *Application for Conversion*, 22 September 2004, op. cit., pp. 35–7.

- a 330 kV connection between Kempsey and Port Macquarie operating at 132 kV
- a new 330 kV connection between Armidale and Kempsey, which may require reconstruction of parts of the existing 132 kV Armidale–Kempsey line
- a new 330/132 kV substation at Port Macquarie.

Figure 7.1 shows the location of the proposed NSW transmission augmentations.[68]

Figure 7.1 Supply system to the NSW north coast



Source: TransGrid and Country Energy, *Development of Electricity Supply to the New South Wales Mid North Coast, Final Report*, Sydney, October 2003, p. 5.

Evaluating DJV's proposed network augmentation deferral benefits involves considering the timing and cost of the proposed augmentations in:

- the absence of Directlink (the 'without Directlink' or reference case)

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68 See appendix D for a system diagram of the Greenbank–Maudsland augmentation and appendix E for a system diagram of the Dumaresq–Lismore augmentation.

- the presence of Directlink (the 'with Directlink' case)
- the presence of Directlink's alternative projects (the 'with alternative projects' case).

The difference between the present values of the network augmentation cost in the reference case and the 'with Directlink' case (or one of its alternative projects) is the market benefit attributable to Directlink (or one of its alternative projects). This chapter sets out both cases (the 'without Directlink' and the 'with Directlink' cases), and considers the associated network augmentation deferral benefits in turn. The network deferral benefits of Directlink's alternative projects (alternatives 1, 2 and 3) are detailed in appendix F and summarised in section 7.5.

7.3 The 'without Directlink' (or reference) case

DJV and its consultant, BRW, identified and proposed a set of reliability augmentations that Powerlink and TransGrid will undertake to alleviate expected network constraints. These constraints are emerging on the Gold Coast and the far north coast of NSW from 2005, without Directlink or one of its alternative projects.[69]

To the extent that each alternative projects defers the reference case, market participants benefit from the delay in the associated network augmentation's capital and operating expenditures. This benefit is represented financially as the difference between the present value of the capital and operating costs under the reference case and that under each of the alternative projects. While the estimated capital and operating costs remain the same in each case, their present value differs as a result of the altered timing for the augmentations.

Evaluating the reference case proposed by DJV involves:

- forecasting growth in demand for electricity for the relevant regions of the NEM
- identifying potential failures to meet reliability standards within the relevant regions of the NEM
- identifying the network augmentations that would be developed by the relevant TNSPs to meet the reliability standards without Directlink or one of its alternative projects
- estimating the costs of the relevant network augmentations.

7.3.1 Expected growth in demand

The need to augment the transmission network is directly related to the amount of electricity flowing across that network. If the power transferred across a line or transformer in the network exceeds a certain level, then another critical element of the network is removed from service, then the line or transformer may be overloaded, or it may not be possible to maintain adequate power supply in the network. Growth in

[69] BRW, op. cit., pp. 29–32, 35–47; id., *BRW Draft Explanation to Review of Costs and Deferment Benefits*, 8 February 2005, pp. 1–3.

electricity demand in the relevant regions and the consequent levels of power transfer are thus key determinants for augmenting the network.

DJV's application

BRW determined the load forecasts using information from the TransGrid and Powerlink 2004 annual planning reports, and information provided by Country Energy for the network demands between Lismore and Mullumbimby. Growth forecasts after 2012–13 are outside TransGrid and Powerlink's planning horizons. BRW thus assumed the same growth each year: 26–27 MW per year for the Gold Coast and 19 MW per year for the far north coast of NSW.

In summary, BRW obtained the medium load forecasts for the Gold Coast from Powerlink's 2004 annual planning report. The low and high growth rates for the Gold Coast were calculated by scaling the medium growth rates in proportion to published Queensland low and high growth scenario forecasts. BRW obtained the medium load forecasts for the far north of NSW from TransGrid's 2004 annual planning report. The low and high growth forecasts for the far north of NSW were determined by scaling the expected growth rates in proportion to the published NSW low and high growth scenario forecasts.

Submissions and the consultancy report

Parsons Brinckerhoff Associates (PB Associates) reviewed the growth rates proposed by BRW and considered them to be reasonable.[70] It noted that actual growth rates for both Queensland and the far north coast of NSW have been higher than forecast rates. Both Powerlink and TransGrid, for example, stated that recent load growth for the two regions exceeded forecasts. TransGrid stated that maximum demand during the summer of 2004–05 exceeded the forecast for summer 2006–07.

The AER's considerations

The AER has considered the views of BRW, PB Associates and the TNSPs. BRW's load growth forecasts appear to be reasonable. While the TNSPs indicated that recent demand on the north coast of NSW had exceeded the load forecast, BRW took this into account when developing its forecast. BRW's load forecasts are also consistent with the latest published forecasts available in the market and are used by TNSPs in their annual planning reviews. The AER has thus decided to adopt the load forecasts provided by BRW.

Conclusion

The AER considers that it is reasonable to adopt the load forecasts provided by BRW.

7.3.2 Potential reliability failures

Network service providers (NSP) are required to meet the standards described in schedule 5.1.2 of the National Electricity Code (the code) in accordance with any agreement with NEMMCO or other market participants for connection to the network (a connection agreement).[71] In particular, NSPs must maintain the network to allow

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[70] PB Associates, op. cit., p. 14.

[71] National Electricity Code, clause 5.2.3(b).

the transfer of power with facilities out of service due to certain defined contingency events. The contingency events must include the disconnection of a single generator or transmission line (network reliability standards).

DJV's application

Table 7.1 summarises the contingency events and resulting potential failures to meet reliability standards, as identified by BRW.

Table 7.1 DJV's view of potential reliability failures without Directlink

Loss of line	Date of contingency arising	Reliability failure
Queensland		
Swanbank to Mudgeeraba/Molendinar (Line 805 or 806)	2005–06 summer	Voltage stability limits exceeded within the Gold Coast network.
New South Wales		
Armidale to Lismore (line 89)	2003–04 summer	The 132 kV line between Armidale and Koolkhan (line 966) overloaded.
Line 89	2007–08 summer	The 132 kV line between Koolkhan and Lismore (line 967) overloaded. A voltage constraint would appear in 2009–10.
Glen Innes to Tenterfield line	2007–08 summer	The Tenterfield to Lismore 132 kV line is expected to be decommissioned during construction of the Dumaresq line. In the absence of this line, Tenterfield is serviced by only one line and Country Energy does not meet its network reliability obligation to Tenterfield.
Armidale to Kempsey (line 965) or Armidale to Coffs Harbour (line 96C) and Kempsey to Port Macquarie (line 96G)	2004 winter	Voltage regulation limits would be reached and customers would be exposed to low voltage conditions in the Coffs Harbour, Kempsey and Port Macquarie areas.

Submissions and the consultancy report

PB Associates reviewed and agreed with the emerging reliability issues identified by BRW.[72] TransGrid advised that line 966 is at risk of being overloaded if there is an outage on line 89. It stated that load growth in the far north coast of NSW has recently exceeded forecasts despite earlier planning suggesting that supply for the area would be adequate until 2007.

The AER's considerations

The AER has considered the views of BRW and PB Associates, and discussions held with CHC Associates and TransGrid. It appears reasonable that the relevant contingency events and potential failures to meet reliability standards are those identified in table 7.1.

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[72] PB Associates, op. cit., pp. 22–4.

Conclusion

The AER considers that it is reasonable, for this regulatory test assessment, to adopt the contingency events and potential failures to meet reliability standards that BRW identified.

7.3.3 Expected reliability augmentations in the reference case

Load growth in the relevant areas will eventually cause the network loading to exceed its capacity. To maintain service standards, particularly the network reliability obligation:

- TNSPs can augment their networks to allow the relevant areas of the network to handle greater loads
- TNSPs can introduce demand management programs to reduce load demands
- additional generation can be introduced to provide additional power to the relevant area and alter the distribution of power across the network.

To the extent that TNSPs augment their networks, the second limb of the regulatory test requires the augmentations to minimise the net present value (NPV) of the costs of meeting the reliability standards.

DJV's application

BRW identified the augmentations required to address the potential failures to meet reliability standards (figure 7.2 and table 7.2).

Figure 7.2 DJV's view of the expected timing of augmentations without Directlink (medium growth)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec
Queensland																		
Without Directlink				Greenbank augmentation														
NSW – Line 966																		
Without Directlink		Line 966																
NSW – Dumaresq line																		
Without Directlink						Dumaresq line												
NSW – Tenterfield																		
Without Directlink						Tenterfield line or substation												
NSW – Port Macquarie augmentations																		
Without Directlink							Port Macquarie augmentation											

Table 7.2 DJV's view of the expected reliability failures and augmentations without Directlink (medium growth)

Loss of line	Date of contingency arising	Reliability failure	Required augmentations	Expected commissioning date
Queensland				
Swanbank to Mudgeeraba/ Molendinar (line 805 or 806)	2005–06 summer	Voltage stability limits exceeded within the Gold Coast network.	A new 275 kV Greenbank switchyard and a new double circuit 275 kV line between Greenbank and Molendinar substation (Greenbank augmentations)	2005–06 summer
NSW				
Armidale to Lismore (line 89)	2003–04 summer	Line 966 overloaded.	An uprating of the 132 kV line from Armidale to Koolkhan (line 966)	2003–04 summer
Line 89	2007–08 summer	Line 967 overloaded. A voltage constraint would appear in 2009–10.	A new 330 kV line from Dumaresq to Lismore (Dumaresq line)	2007–08 summer
Glen Innes to Tenterfield	2007–08 summer	The Tenterfield to Lismore 132 kV line expected to be decommissioned during construction of the Dumaresq line. Without this line, Tenterfield serviced by only one line and Country Energy unable to meet its network reliability obligation to Tenterfield.	A new line from Glen Innes to Tenterfield or a 330 kV Tenterfield substation (Tenterfield line or substation)	2007–08 summer
Armidale to Kempsey (line 965) or Armidale to Coffs Harbour (line 96C) and Kempsey to Port Macquarie (line 96G)	2004 winter	Voltage regulation limits reached and customers exposed to low voltage conditions in the Coffs Harbour, Kempsey and Port Macquarie areas.	A 330 kV connection between Kempsey and Port Macquarie initially operating at 132 kV, a 330 kV line between Armidale and Kempsey, and a 330/132 kV substation at Port Macquarie (together, the Port Macquarie augmentations)	2008–09 summer

Submissions and the consultancy report

Queensland—Greenbank augmentations

PB Associates reviewed and agreed with the nature and timing of augmentations for Queensland as proposed by DJV.

New South Wales—Dumaresq line

TransGrid advised the AER that the absence of Directlink would mean it has to commission the Dumaresq–Lismore 330 kV line by the summer of 2007–08. Prior to the construction of this line, up to 50 MW of load is at risk for up to 200 hours per year. Given the required lead time, however, it is not possible for TransGrid to complete construction of the line before the summer of 2007–08.

PB Associates disagreed with the nature and timing of some of the augmentations for NSW proposed by DJV. It stated that the uprating of line 966 and the proposed local generation at Broadwater appear certain to proceed in the near term and will defer the required timing of the Dumaresq–Lismore line to 2010–11.

PB Associates stated that TransGrid had advised it that line 966 would be uprated and additional capacitors would be installed at the Koolkhan, Lismore and Nambucca substations by the summer of 2006–07. It determined that uprating line 966 will increase its thermal rating and defer the need to construct the Dumaresq line until after 2008–09. It concluded that voltage collapse from 2009–10 becomes the limiting factor and that 28 MW of power injection at Lismore is required to maintain voltage levels at the Koolkhan and Lismore substations.

PB Associates stated that it had met with Delta Electricity (Delta) and been advised:

> … that 30 MW bagasse generators will be installed and connected to Country Energy's distribution networks at the Broadwater and Condong sugar mills. Both projects are significantly advanced with financial close expected early December 2004.
>
> The additional generator at Broadwater Mill will be connected to Country Energy's 66 kV network and will provide direct support to the Lismore 132/66 kV substation. When operational the generator will be capable of exporting 26.9 MW during the crushing season, July to December each year, and 26.7MW during the non crushing season. This new generator at Broadwater Mill is due to be commissioned in March 2007.
>
> The generator will operate at base-load with an estimated annual availability of 95%. As an embedded generator the unit will be incentivised to operate at time of peak transmission system demand – by virtue of its ability to earn the commercial benefits associated with a reduction in Country Energy's liability for transmission use of system charges (TUoS).
>
> The new generator to be installed at the Condong sugar mill is due to be commissioned in December 2007 and can export 23.6 MW during the crushing season and 26 MW during the non crushing season, January to June each year. PB Associates are not aware that the Condong generation will offer any network support benefits other than to possibly relieve the constraint on supply from the Queensland network for a short time around 2015–16.[73]

Allowing 95 per cent availability for the generator and recognising the incentive for the generator to operate over peak periods, PB Associates concluded that the need to construct the Dumaresq line will be further deferred from 2008–09 until after 2010–11. It supported its analysis using statements from Powerlink's planning report:

> … that northern NSW supply requirements are addressed through a modelled arrangement for network support from either Directlink or embedded generation from mid 2006 onwards.

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73 ibid., p. 26.

> It is assumed that this is capable of addressing the Far North Coast of NSW supply requirements for six years, with network augmentation being required in NSW by 2012.[74]

DJV responded to the PB Associates' report by stating that it does not believe the proposed co-generation plants at Broadwater and Condong will defer the Dumaresq line.[75] It stated that:

- the co-generation plants are not committed projects and 'for this reason alone' cannot be relied on to provide critical network support
- the Broadwater plant would be a single generation unit. DJV and BRW are not aware of another instance in the NEM where a single biomass generation unit has been accepted as a provider of network support services.
- PB Associates has not adequately assessed the supply and handling constraints on availability associated with biomass generators, particularly given that the Broadwater plants rely on unsecured biomass fuel source outside of the sugar milling season.
- PB Associates has inconsistently required 99 per cent availability for Directlink, but only 95 per cent availability for the biomass generators
- NSPs cannot and will not rely solely on market incentives to ensure network support services are available at critical times, but rather will require contractually binding arrangements containing substantial penalties for nonperformance
- Delta does not anticipate entering such a contract, as evidenced by its failure to respond to requests of Powerlink or TransGrid for information on the alleviation of emerging network constraints
- Powerlink advised DJV that no statements made in its final report for the Gold Coast/Tweed area support any conclusion regarding deferral periods or costs associated with possible network support to the far north coast of NSW.

BRW explicitly recognised that the Broadwater generator could defer the voltage collapse at Koolkhan:

> BRW has modelled the Broadwater generator and its relatively weak 66 kV connection to the Lismore substation. When operating, the net injection to the Lismore bus would be approximately 25 MW and the results confirm that this development potentially could defer the voltage collapse at Koolkhan by two years.[76]

However, BRW went on to state that:

> Whilst the injection could provide some improvement to system conditions in the Lismore and Clarence areas during periods of generator operation, it is not able to provide any significant support to areas beyond this region. Current 132 kV voltage levels in the Port

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[74] Powerlink and Energex, *Proposed New Large Network Asset—Gold Coast and Tweed Areas Final Report*, July 2004, p. 35.

[75] DJV, *Submission Response to PB Associates Report*, op, cit., p. 15.

[76] BRW, *Directlink: BRW Comments on PB Associates Report of 26 November 2004*, 14 January 2005, p. 3.

> Macquarie area are at the lower end of acceptable levels even under normal operation. Directlink has the capacity to provide a significant level of support to the voltage at Port Macquarie, particularly in the period up until the establishment of the Coffs Harbour 330/132 kV transformation before the winter of 2006 and following that in the event of a loss of the Armidale – Coffs Harbour 330 kV line up until the completion of the anticipated Armidale – Port Macquarie 330 kV line in 2008/09. A 30 MW generator at Broadwater, when operating, cannot provide any significant voltage support to the Port Macquarie area.[77]

BRW also stated that it discussed the proposed co-generation plants with TransGrid and Country Energy on 27 August 2004, and it was agreed that the modelling should not allow for these developments. It noted that the agreement reflected the lack of confidence in relying on a 'single shaft' installation for the provision of network support.

Sunshine Electricity, the joint venture between Delta Electricity and the Broadwater Sugar Mill Sunshine, stated that it:

> … does not contemplate the generating units operating in a manner that could be interpreted as providing reliability support to the TransGrid transmission network.
>
> Sunshine Electricity intends to operate the generating plant at the highest level of utilisation possible, as non-scheduled generators associated with an industrial process. It does not intend to enter into a network support agreement with TransGrid or Country Energy that would expose the plant owners to financial penalties or indemnities when the units are not available at critical times. This would create obligations and risks for the project that it is not designed to manage. The only revenue benefit the project forecasts from network operators is avoided use of system payments.[78]

Country Energy stated that it is not willing to rely on a single shaft generator. TransGrid stated that it considered this position reasonable and consistent with Sunshine's reluctance to enter into a network support agreement.

On 23 May 2005, Delta advised that the Broadwater and Condong generators have reached financial close and thus are committed projects. On 14 September 2005, Metgasco wrote to the AER advising that it is developing embedded power generation facilities in the north east of NSW. It stated that it intends to develop a large scale capacity gas generator within two years and would assist with deferring the Dumaresq line.

New South Wales—line 966

Following the release of PB Associates' report, TransGrid stated that there is currently a risk of overloading line 966 in the contingency of loss of line 89.[79] TransGrid stated that in the event of such an outage:

> Under conditions of high summer load, an outage of 89 line would result in the sustained emergency rating of 966 line (but not its short time rating) being exceeded and possibly also unacceptably low voltages in the area. In these circumstances, load shedding schemes at Lismore and Koolkhan would either operate automatically in response to low voltages or be

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77 ibid., p. 3.

78 Sunshine Electricity, Letter to the Australian Competition and Consumer Commission, 25 February 2005.

79 TransGrid, Letter to the ACCC, 11 March 2005, p. 3.

> initiated by system operators within a short time bringing 966 back within its sustained emergency rating.
>
> Supply to interrupted loads would then be restored as quickly as possible. This could be facilitated by favourable circumstances such as:
>
> - prompt return of 89 line to service;
> - a reduction in other loads in the area (as part of their normal daily load cycle), or
> - the availability of alternative supplies such as Directlink (should there be sufficient capacity in the Queensland system) or embedded generation (should that be developed). In the most favourable circumstances, in which alternative supplies are available pre-emptively, it may not be necessary to interrupt any load.
>
> In short, the voltage collapse scenario contemplated by BRW should not arise from a single contingency, and restoration of interrupted load could be facilitated by a number of factors, including the possible availability of support from Directlink.[80]

DJV responded to TransGrid's letter, arguing that TransGrid recognised the potential for line 966 to be overloaded after the loss of line 89. It stated that the potential for this overload to occur was foreseeable from at least July 2003. In support, DJV compared Country Energy's peak forecasts for locations in the far north of NSW with the demand on 20 February 2004. On this day, the load for the far north of NSW was within summer peak forecasts, but BRW's analysis (based on NEMMCO data files) showed that the loading on line 966 would have exceeded its sustained emergency rating if line 89 had tripped.[81]

TransGrid stated that a planner looking at the NSW north coast area in 2002 would not have expected the subsequent growth in demand. It supplied the following figures 7.3 and 7.4, which compare actual demand on the far and mid north coast of NSW to that forecast by Country Energy in 2003–04.

Load growth in the far north of NSW had recently exceeded that anticipated in TransGrid's earlier planning, such that the practical need to uprate line 966 for the summer of 2006–07 had only been recently identified. TransGrid stated that it would not have had to uprate line 966 if the forecasts were correct; instead, it would have relied on the commissioning of the Dumaresq line in the summer of 2007–08 to address emerging reliability issues in the area.

[80] ibid. p. 3.
[81] DJV, *Submission in Response to Letters from TransGrid and PB Associates*, Port Macquarie, 6 April 2005,
pp. 2–3.

Figure 7.3 Comparison of actual and forecast load growth on the far north coast of NSW

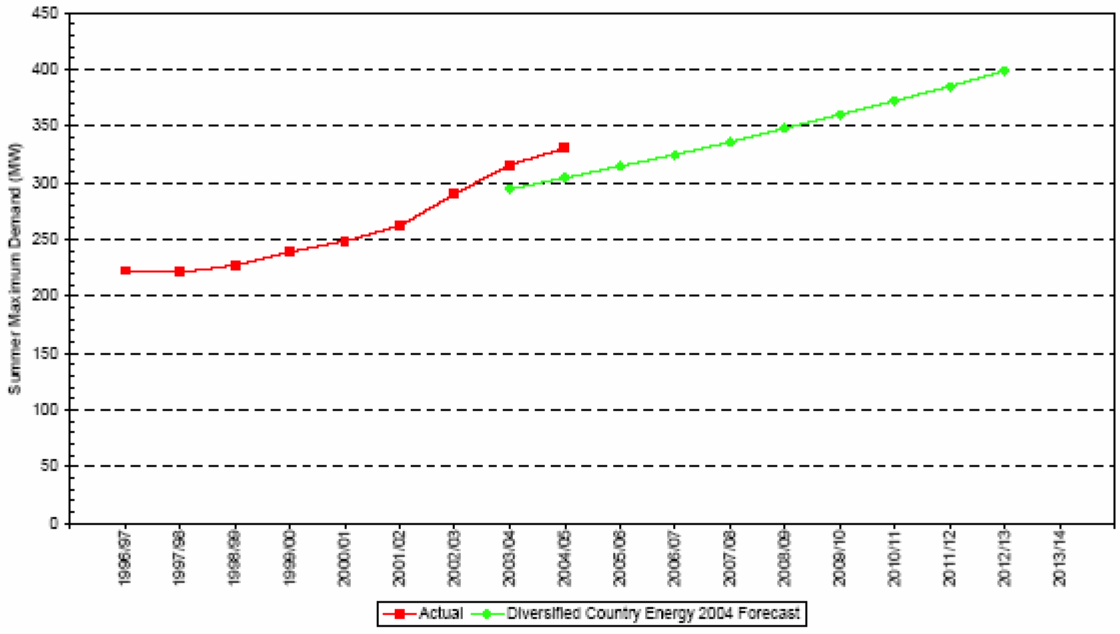
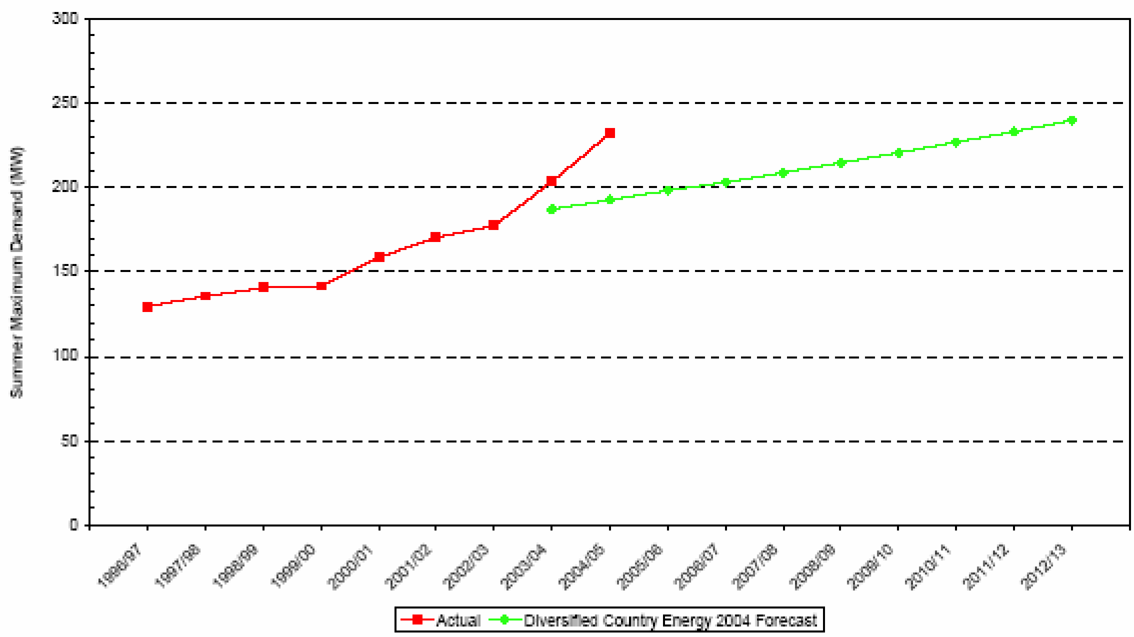


Figure 7.4 Comparison of actual and forecast load growth on the mid north coast of NSW



New South Wales—Tenterfield back-up supply

TransGrid acknowledged that options for the back-up supply of power to Tenterfield would need to be considered after the decommissioning of the Tenterfield–Lismore

132 kV line.[82] However, TransGrid noted that the ultimate solution would be the outcome of joint planning involving Country Energy.

New South Wales—Port Macquarie augmentations

BRW stated that its modelling is based on the assumption that the 330 kV augmentations to Port Macquarie would be commissioned in 2008–09, which TransGrid indicated in consultations on the modelling assumptions.

Summary of augmentations

Figure 7.5 shows the positions of various parties on the expected augmentations under the reference case.

Figure 7.5 Various parties' views of the expected timing of augmentations without Directlink (medium growth)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec
Queensland																		
DJV				Greenbank augmentation														
PB				Greenbank augmentation														
NSW – Line 966																		
DJV		Line 966																
PB				Line 966														
TransGrid					Line 966													
NSW – Dumaresq line																		
DJV						Dumaresq line												
PB						Broadwater			Dumaresq line									
TransGrid						Dumaresq line												
NSW – Tenterfield																		
DJV						Tenterfield line or substation												
PB						Broadwater			Tenterfield line or substation									
TransGrid						Tenterfield line or substation												
NSW – Port Macquarie augmentations																		
DJV							Port Macquarie augmentation											
TransGrid							Port Macquarie augmentation											

The AER's considerations

Queensland—Greenbank augmentations

The AER has considered the views of BRW and PB Associates that the Greenbank augmentation is required in 2005–06 to meet the constraint identified in Powerlink's south east Queensland network. It considers that this is a reasonable requirement.

New South Wales—Dumaresq line

In light of the Broadwater generator achieving financial close, the AER has considered the advice of PB Associates that the generator is likely to be commissioned around the middle of 2007. Further, it has considered PB Associates' advice that the generator has the potential to provide sufficient power into Lismore to

82 TransGrid, Letter to the ACCC, op. cit, p. 5.

defer construction of the Dumaresq line and has incentives to operate during the summer peak period.

The AER also acknowledges the concerns of Country Energy and TransGrid that the Broadwater generator is a single shaft generator and relies on biomass, rather than a more conventional fuel source. And it has considered that Country Energy and TransGrid would not rely on a single shaft generator to defer augmentations in the area. The augmentations are subject to joint planning processes involving TransGrid and Country Energy, and the AER is guided by their evaluations.

In relation to the information provided by Metgasco, the AER notes that the proposed gas power generation is still in the early stages of development. That generator is not yet a committed project, and network support agreements, while being negotiated, have not been finalised.

The AER considers that it appears reasonable, on balance, that TransGrid would need to commission the Dumaresq line for the summer of 2007–08.

New South Wales—line 966

The AER has considered the views of BRW and TransGrid. BRW's load modelling indicates that the potential for line 966 to be overloaded following an outage of line 89 was foreseeable from July 2003. TransGrid accepted that the possibility of line 966 being overloaded exists, but indicated that it has not uprated line 966 because it did not anticipate when planning its network in 2003–04 that load levels in the far north coast of NSW would reach current levels. Although TransGrid stated that it would have relied on the construction of the Dumaresq–Lismore line by the summer of 2007–08 to meet emerging reliability constraints in the far north coast of NSW, these constraints will occur before the summer of 2007–08.

TransGrid is now aware of them due to the load growth in the far north coast of NSW. Given the scale of the Dumaresq–Lismore augmentation and TransGrid's submissions, the AER considers that it is not possible for TransGrid to commission the Dumaresq–Lismore line before the summer of 2007–08. The practical work that TransGrid has identified as a solution for the summer of 2006–07 is to uprate line 966 to improve conditions in that region. The AER accepts that this uprating is necessary to help address the reliability constraints.

New South Wales—Tenterfield back-up supply

The AER has considered the view of BRW that the Tenterfield–Lismore 132 kV line is expected to be decommissioned during construction of the Dumaresq–Lismore 330 kV line. It appears reasonable that the timing of the commissioning of works to maintain back-up supply to Tenterfield will be concurrent with the commissioning of the Dumaresq line (that is, 2007–08).

New South Wales—Port Macquarie augmentations

Neither DJV nor BRW have detailed their expectations about the stages of the Port Macquarie augmentations and their likely timing. BRW's modelling, however, assumed the Port Macquarie augmentations would be commissioned in 2008–09. Without specific information in DJV's application, the AER has also considered the likely timings indicated by TransGrid in its annual planning report and other public documents such as TransGrid's proposed capital investment program for its 2004–2009 revenue cap and PB Associates' review of TransGrid's capital expenditure program.

TransGrid's 2004 annual planning report identified the following three stages for the augmentations to the mid north coast area of NSW:

1. Install a 330/132 kV substation and turn in line 89 (previously from Armidale to Lismore) to Coffs Harbour.

2. Form a second 132 kV connection between Coffs Harbour and Kempsey by reconnecting an existing 66 kV line constructed for 132 kV and converting substations from 66 kV to 132 kV.

3. Construct a second 132 kV connection between Kempsey and Port Macquarie using 330 kV construction.

TransGrid also foreshadowed the future construction of a 330 kV line from Armidale to connect to the above 330 kV construction line near Kempsey, and the construction of a 330/132 kV substation at Port Macquarie.[83] The works noted in DJV's application as the 'Port Macquarie augmentations' are those described in the third stage and TransGrid's foreshadowed future constructions. These works will need to be staged over several years, most likely spanning the indicative date of 2008–09 assumed by BRW. BRW has not claimed that Directlink can defer the works described in the first two stages above, and they are not mentioned in DJV's supplementary submission of 8 February 2005.

Regarding the future component of the Port Macquarie augmentations, PB Associates' review of TransGrid's capital expenditure program stated that:

> The solution proposed by TransGrid to overcome the low voltage conditions following the loss of the Armidale to Coffs 330kV line or the Kempsey to Port Macquarie 132kV line is to establish a new 330/132kV substation at Port Macquarie. TransGrid has proposed this new connection to be in service for the winter of 2010.
>
> To establish this new 330kV connection at Port Macquarie, TransGrid are proposing to rebuild the existing 132kV line from Armidale to Kempsey at 330kV and to construct a new 330kV line from Kempsey to Port Macquarie. Although these 330kV lines are due to be in service by 2010, TransGrid need to advance some of the re-build of the existing 132kV line to 2009 as the line must be taken out of service to re-build at 330kV and this can only be achieved during spring and autumn windows when minimum load conditions exist.[84]

[83] id., *NSW Annual Planning Report*, Sydney, 2004, p. 52.

[84] PB Associates, *TransGrid's Forward Capital Expenditure Requirements 2004/05 to 2009/09, An Indepenpent Review*, January 2005, p. 71.

The indicative timing of 2008–09 for commissioning the Port Macquarie augmentations thus seems reasonable. The AER also considers that it is appropriate to omit reference to the earlier mid north coast NSW works that are not claimed to be affected by Directlink.

Conclusion

Table 7.3 and figure 7.6 summarise the AER's view of the reference case augmentations.

Table 7.3 The AER's view of the expected reliability failures and augmentations without Directlink (medium growth)

Loss of line	Date of contingency arising	Reliability failure	Required augmentations	Expected commissioning date
Queensland				
Line 805 or 806	2005–06 summer	Voltage stability limits exceeded within the Gold Coast network.	Greenbank augmentations	2005–06 summer
NSW				
Line 89	2003–04 summer	Line 966 overloaded.	Uprating of line 966	2006–07 summer
Line 89	2007–08 summer	Line 967 overloaded. A voltage constraint would appear in 2009–10.	Dumaresq line	2007–08 summer
Glen Innes–Tenterfield line	2007–08 summer	The Tenterfield–Lismore 132 kV line expected to be decommissioned during construction of the Dumaresq line. Without this line, Tenterfield serviced by only one line and Country Energy unable to meet its network reliability obligation to Tenterfield.	Tenterfield line or substation	2007–08 summer
Line 965 or line 96C and line 96G	2004 winter	Voltage regulation limits reached and customers exposed to low voltage conditions in the Coffs Harbour, Kempsey and Port Macquarie areas.	Port Macquarie augmentations	2008–09 summer

Figure 7.6 The AER's view on the expected timing of augmentations without Directlink (medium growth)

	2002 Dec	2003 Dec	2004 Dec	2005 Dec	2006 Dec	2007 Dec	2008 Dec	2009 Dec	2010 Dec	2011 Dec	2012 Dec	2013 Dec	2014 Dec	2015 Dec	2016 Dec	2017 Dec	2018 Dec	2019 Dec
Queensland																		
DJV				Greenbank augmentation														
AER				Greenbank augmentation														
NSW – Line 966																		
DJV		Line 966																
AER					Line 966													
NSW – Dumaresq line																		
DJV						Dumaresq line												
AER						Dumaresq line												
NSW – Tenterfield																		
DJV						Tenterfield line												
AER						Tenterfield line												
NSW – Port Macquarie augmentations																		
DJV							Port Macquarie augmentation											
AER							Port Macquarie augmentation											

7.3.4 Transmission network augmentation costs

DJV's application

Including interest during construction (IDC), a contingency of 10 per cent in the project capital cost estimate, and the lifecycle operating expenditure (opex), BRW's estimates of the cost of the network augmentations are shown in table 7.4 (based on a 9 per cent discount rate).

Table 7.4 DJV's estimated costs for reference case augmentations ($ million, 1 July 2005)

Capital cost components	Greenbank augmentations	Dumaresq line	Line 966	Tenterfield back-up	Port Macquarie augmentations	Total
Project cost(a)	50.8	148.0	11.3	14.0–14.6	127.3	351.4–352.0
IDC	2.4	10.1	0.5	0.9–1.5	9.4	23.3–23.9
Lifecycle opex(b)	16.9	17.7	na	na(c)	16.9	51.5
Total	70.1	175.8	11.8	15.5–16.0	153.6	426.8–427.3

(a) The line costs assume full overhead construction.

(b) The lifecycle opex amount has been calculated as the present value of the annual opex required over the assumed life of the assets.

(c) The opex for the Tenterfield back-up options is assumed to be incorporated in the opex estimate of the Dumaresq line.

na Not applicable.

Submissions and the consultancy report

IDC and contingencies

PB Associates stated that IDC and contingencies should be excluded from the costs of the reference case:

> For the alternatives which are being assumed as proxies for the Directlink assets, the construction and commissioning dates are assumed to be the same, i.e. 1 July 2005. In this instance, since there is no delay between conversion date (becoming a regulated asset) and revenue derivation, there is no requirement in our view to include IDCs. To include IDCs for estimating the present value of investments for proposed alternatives to Directlink would, in our view result in double counting, as the cost of capital is implicit in the discount rate.
>
> In the case of contingencies, these are costs in addition to those estimated based on individual components and therefore reflect a measure of inefficiency which is not consistent with the requirements of the National Electricity Code. The costs assumed by PB Associates in the evaluation of alternatives, and also assumed by BRW in its analysis for the DJV, include estimated actual costs and therefore do not require an additional contingency allowance.[85]

DJV responded that BRW's estimate of the costs of each augmentation is an estimate of the costs to an NSP when purchasing the asset under an engineering, procurement and construction (EPC) contract. In the case of IDC, the costs incurred under this contract occur over four to five years and not at the end of the contract, so an allowance should be made for the cost of capital to the purchaser.

In the case of the contingency allowance, DJV argued that an EPC contract would allow for various uncertainties and risks, and that an EPC contractor would have a real expectation of incurring costs beyond those that can reasonably be estimated. It noted that the ACCC has allowed for both IDC and contingencies in previous regulatory decisions.

Cost of easement for the Queensland reference case

PB Associates calculated the cost of the reference case excluding easement costs for the Greenbank augmentation in Queensland. It stated that these easements have already been acquired by Powerlink and will not be deferred. It also noted that Powerlink indicated that the estimates of capital costs in its planning report exclude the cost of easements.

DJV stated that:

> To avoid distorting the outcomes of the Regulatory Test, PB Associates should also include the easement costs of the Queensland reliability augmentations even though the easements have already been purchased. To exclude the cost of substantial cost items such as easements could create perverse incentives for project proponents conducting the test for this type of project:
>
> - Project proponents could make their project more attractive in the light of the Regulatory Test by pre-purchasing major cost items; and

[85] PB Associates, *Review of Directlink Conversion Application*, op. cit., pp. 19–20.

- Alternatives 0, 1, 2 and 3 contain cost components that have already been procured such as substation sites, cable and converters. In fact all the cost items for Alternative 0 have been procured and if PB Associates' logic prevails, it would have a capital cost of zero.

> For the Regulatory Test to provide equitable consideration of all the alternative projects, all project specific costs should be included whether sunk or otherwise. This is especially the case where the Regulatory Test is being used to value an existing asset.[86]

Nonetheless, BRW's estimated cost for the Greenbank augmentation was based on Powerlink's costing, and no easement costs have been included.[87]

Operating and maintenance expenditure

PB Associates estimated the operating costs of the reference case as 2 per cent of capital expenditure (capex), as indicated by TransGrid during discussions.[88] It also noted that the Dumaresq–Lismore 330 kV line would replace an existing Tenterfield–Lismore 132 kV line for approximately two thirds of its length. This opex saving means the corresponding incremental (for one third of its length) opex should be allowed.

DJV stated that estimating opex using 2 per cent of capital costs is not a better estimate of the opex associated with the reference case than using locational and technical characteristics of each alternative project as BRW did.[89] TransGrid's submission noted that PB Associates' report does not provide any supporting information for why 2 per cent of the capital cost is an appropriate estimate of opex. On 21 March 2005, PB Associates provided additional information that explained that a 2 per cent capital cost rule of thumb provides an appropriate estimate of opex.

New South Wales—Tenterfield back up supply

DJV's supplementary submission of 8 February 2005 recalculated the network deferral benefits and included the cost of retaining a back-up supply to Tenterfield following the dismantling of the Tenterfield–Lismore 132 kV line during construction of the Dumaresq–Lismore 330 kV line. BRW assessed a second Glen Innes–Tenterfield 132 kV circuit to be the lowest cost option, assuming that there are no environmental constraints on its construction and that TransGrid's planned Glen Innes – Inverell 132 kV augmentation has been completed. BRW noted that:

> A 330 kV Tenterfield substation option could be a lower cost alternative in the event of any significant environmental constraint to a line development or if the Glen Innes – Inverell 132 kV augmentation has not been completed. The second circuit (or a substation) would have to be constructed at the same time as the Dumaresq–Lismore 330 kV line.[90]

It also noted that the opex for the second Glen Innes–Tenterfield circuit would offset savings in the 132 kV opex through the removal of the Tenterfield–Lismore 132 kV line. Accounting for the higher opex costs for 330 kV substations and lines, BRW assessed there would be no saving in overall opex for the Dumaresq–Lismore line

86 DJV, *Submission in Response to PB Associates Report*, op. cit., pp. 23–4.
87 BRW, *Selection and Assessment of Alternative Projects to Conversion Application to ACCC*, 8 February 2005, p. 7.
88 PB Associates, *Review of Directlink Conversion Application*, op. cit., p. 30.
89 DJV, *Submission in Response to PB Associates Report*, op. cit., p. 25.
90 BRW, *BRW Draft Explanation to Review of Costs and Deferment Benefits*, op. cit., pp. 2–3.

from removing the existing Tenterfield–Lismore 132 kV line. It has thus maintained its previous estimate of opex for the Dumaresq–Lismore line because the savings are assumed to be offset by the opex of the second Glen Innes–Tenterfield circuit.

On 7 March 2005, the ACCC wrote to Country Energy requesting its views on options for maintaining back-up supply to Tenterfield during the construction of the anticipated Dumaresq–Lismore line. The letter noted that winter peak demand in Tenterfield is around 6 MW and would not normally justify construction of a 132 kV line. It also noted other possible options of extending the 66 kV line from Glen Innes and procuring grid support. The ACCC raised similar queries with TransGrid in a letter dated 28 February 2005.

On 15 March 2005, Country Energy replied to the ACCC, stating that a second 132 kV line from Glen Innes to Tenterfield is the lowest cost option and that it had explored the possibility of supplying Tenterfield using alternative means such as a radial 66 kV line from a neighbouring network or embedded generation.[91] Regarding a 66 kV line, it stated that there is little opportunity to increase interconnection from neighbouring lines. Further, it could not rely on extending the 66 kV line from Glen Innes given loading and distances. Regarding embedded generation, Country Energy stated that it had investigated demand management and embedded generation opportunities as part of the joint publication with TransGrid, the *Emerging Transmission Network Limitations on the New South Wales Far North Coast*. According to Country Energy, this investigation revealed that feasible and economically efficient opportunities for non-network alternatives for grid support are inadequate to provide the back-up support.

Country Energy emphasised that any option to provide back-up supply to Tenterfield would require joint planning with TransGrid. In its letter of 11 March 2005, TransGrid stated that:

> Reliability criteria are agreed as part of the joint planning process. An appropriate standard for Tenterfield (in the event that the existing Tenterfield–Lismore 132 kV line is rebuilt as a 330 kV line) has yet to be agreed with Country Energy. To incorporate community attitudes and other relevant factors, we would expect that this issue would be addressed much closer to the time at which the 132 kV line may be rebuilt.
>
> TransGrid recognises that the magnitude of the Tenterfield load (less than 10 MW) is presently considerably less than that at which a second 132 kV supply would normally be provided. However, in light of generally increasing community expectations, a reduction in reliability from present levels may not be acceptable. TransGrid accepts that Country Energy, as our customer, is responsible in the final analysis to accept the level of reliability required. At Tenterfield, this may require the adoption of a suitable non-network/standby generation solution or partial network support at lower voltage.[92]

TransGrid stated that it had not compared the costs of alternatives for supplying Tenterfield, but believed that a 66 kV line from Glen Innes may be cheaper than a 132 kV line and have adequate capacity.

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[91] Country Energy, *Information on Alternative Back-up Supply to Tenterfield*, 2005, pp. 3, 5.
[92] TransGrid, Letter to the ACCC, op. cit., p. 5.

In May 2005, following a request for additional information from the ACCC, DJV provided a BRW report that estimated the costs, and assessed the technical issues, of options for back-up supply to Tenterfield. BRW concluded that the three lowest cost and technically feasible options were:

1. a 330/132 kV substation connecting Tenterfield to the Dumaresq–Lismore 330 kV line

2. a 66 kV line from the Emmaville substation

3. 7.5–10.5 mega volt amperes (MVA) of standby diesel generation at Tenterfield.[93]

BRW estimated the costs of each option to be as shown in table 7.5 (based on a 9 per cent discount rate).

Table 7.5 BRW's estimated costs for Tenterfield back-up supply options ($ million, 1 July 2005)

Capital cost components	330/132 kV substation	Emmaville 66 kV line	Diesel generation
Project cost	14.0	14.6	14.0
IDC	1.5	1.4	0.9
Lifecycle opex[(a)]	1.7	1.7	3.1
Total	17.2	17.7	18.0

(a) When calculating the deferral benefits, the opex for the Tenterfield option is included in the opex estimate for the Dumaresq–Lismore line. The opex for each option is included here for completeness.

BRW stated that these estimated costs are close to each other in magnitude and demonstrate the robustness of the results. It also stated, however, that the cost and relative ranking of the options are sensitive to assumptions. Both the Emmaville 66 kV line and the diesel generation would result in a slight reduction in quality of service to Tenterfield because the operation of either, during a contingency, would result in a short supply interruption.

BRW noted that the operating costs for each option are included in the opex of the Dumaresq–Lismore line and are disclosed separately for comparison only.

The AER's considerations

Interest during contruction, and contingencies

The AER considers that DJV's proposition that IDC constitutes a legitimate cost of an EPC contract appears to be reasonable. Although the augmentations are assumed to be completed by the relevant dates, the construction of the augmentations occur over time, so the costs of construction accrue over a number of years. During this period, the contractor incurs financing charges. No return is provided for the capital cost during the construction period. Rather, the inclusion of IDC brings construction

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93 BRW, *Tenterfield Supply Options: an Analysis of Options to Replace 96L*, July 2005, pp. 4, 7, 20.

costs that occur before commissioning up to their present value at the completion date.

The AER has considered DJV's claim that an EPC contractor would allow for various uncertainties and risks and could expect to incur costs beyond those that can reasonably be estimated. It believes that a contractor would allow for various uncertainties and risks in the form of a contingency allowance. Such contingency allowances reflect a fair estimate of the additional costs that could be expected to be incurred. An overly generous allowance would allow parties to claim inefficiencies as legitimate costs.

For this draft decision, the AER will adopt the 10 per cent contingency allowance proposed by DJV. This amount is consistent with the AER's understanding of the general 'rule of thumb' value used by the industry and the allowance made by the ACCC in the Murraylink decision.

Cost of easement for the Queensland reference case

The AER has considered PB Associates' advice that the Greenbank augmentation should exclude sunk costs such as easements that have already been acquired. These costs were already incurred and will not be deferred by Directlink or any of its alternative projects. The AER thus considers that the advice is reasonable. Further, it notes that BRW's estimated cost for the Queensland reference case did not include any easement costs. Care should be taken in calculating deferral benefits associated with easements. There may be legitimate reasons for acquiring easements before construction—for example, residential development can encroach on space available for construction and increase the cost of acquiring easements in later periods. In appropriate circumstances, even though a project may be deferred, it may not be prudent to defer the purchase of easements.

Operating and maintenance expenditure

BRW estimated the opex of the augmentations based on the pricing of individual components. The AER is aware that a 2 per cent construction cost is typically accepted as a reasonable basis for estimating opex for future network augmentations. Considerable work would need to be undertaken to establish reliable benchmarks that produce fair and balanced comparisons of opex across TNSPs. Given that such benchmarks have not yet been developed, the AER will not yet rely on benchmarking for determining opex.

Chapter 12 discusses the AER's assessment of the opex for the alternative projects. The breakdown of the opex cost items for the reference case augmentations correspond to the opex items listed by BRW for the alternative projects. Several of the opex cost items for the reference case are proportional to those listed for the alternative projects—for example, the Dumaresq–Lismore line has opex cost items such as general management, operating management, operations, commercial/regulatory, financial management, insurance, energy and communications, which are estimated to be 50 per cent of the same opex items in relation to the alternative projects.

The AER adjusted the opex items for the alternative projects, and it could be argued that the same adjustments may apply for the reference case opex. But it has received no other material to assess the appropriateness of the specific opex cost items for the reference case augmentations. For this draft decision, therefore, the AER will adopt BRW's opex estimates for the reference case.

In relation to the opex for the Dumaresq–Lismore 330 kV line, BRW estimated a total opex allowance for this line even though it would replace the existing Tenterfield–Lismore 132 kV line. The Tenterfield–Lismore line is approximately two thirds of the length of the Dumaresq line, so the incremental opex for the Dumaresq line should correspond to one third of the line. The two thirds saving in opex through the dismantling of the Tenterfield–Lismore line during construction of the Dumaresq line would be offset, however, by the opex requirement for the Tenterfield back-up option (330/132 kV substation). BRW's estimated total opex for the Dumaresq–Lismore line, which includes the opex for the Tenterfield option, is thus reasonable (that is, the opex allowance for Tenterfield back-up supply is not separately listed but instead included in the estimated opex for the Dumaresq line).

New South Wales—Tenterfield back up supply

The AER has considered BRW's analysis of the options for back-up supply to Tenterfield on construction of the Dumaresq line and the costing of those options. The lowest cost option, being a minimum cost 330/132 kV substation connecting Tenterfield to the Dumaresq–Lismore line, should reasonably be selected for this regulatory test assessment. The regulatory test requires the construction of the lowest cost option for reliability purposes.

New South Wales—Port Macquarie augmentations

The AER has has not considered the cost of the Port Macquarie augmentations, given an intention to disallow deferral of these items (as discussed in section 7.4.1).

New South Wales—line 966

The AER has not considered the cost of uprating line 966, given an intention to disallow deferral of this item (as discussed in section 7.4.1).

Conclusion

The AER has assessed the information put forward and considers that the cost estimates provided by BRW are appropriate. Including IDC, contingency cost and the lifecycle opex, the AER considers the total cost of the augmentations to be as shown in table 7.6 (based on a 9 per cent discount rate).

Table 7.6 The AER's conclusion on the costs of reference case augmentations ($ million, 1 July 2005)

Capital cost components	Greenbank augmentations	Dumaresq line	Line 966	Tenterfield substation	Port Macquarie augmentations	Total
Project cost	50.8	148.0	11.3	14.0	127.3	351.4
IDC	2.4	10.1	0.5	1.5	9.4	23.9
Lifecycle opex[(a)]	16.9	17.7	na	na[(b)]	16.9	51.4
Total	70.1	175.8	11.8	15.5	153.6	426.8

(a) The lifecycle opex amount has been calculated as the present value of the annual opex required over the assumed life of the assets.

(b) The opex for the Tenterfield substation is included in the opex estimate for the Dumaresq–Lismore line.

na Not applicable.

7.4 The 'with Directlink' case

7.4.1 Expected reliability augmentations in the presence of Directlink

DJV's application

For the 'with Directlink' case, DJV proposed that the timing of required augmentations to address contingency events and potential failures to meet reliability standards would be different from that under the reference case. This is summarised in table 7.7. Figure 7.7 illustrates the impact of the revised timing on the expected augmentations, in the 'with Directlink' case.

Figure 7.7 DJV's view of the expected deferral timing of the reference case with Directlink (medium growth)

	2002 Dec	2003 Dec	2004 Dec	2005 Dec	2006 Dec	2007 Dec	2008 Dec	2009 Dec	2010 Dec	2011 Dec	2012 Dec	2013 Dec	2014 Dec	2015 Dec	2016 Dec	2017 Dec	2018 Dec	2019 Dec
Queensland																		
Without Directlink				Greenbank augmentation														
With Directlink				D/L	Greenbank augmentation													
NSW – Line 966																		
Without Directlink		Line 966																
With Directlink		Directlink																
NSW – Dumaresq line																		
Without Directlink						Dumaresq line												
With Directlink						Directlink										Dumaresq line		
NSW – Tenterfield																		
Without Directlink						Tenterfield substation												
With Directlink						Directlink										Tenterfield		
NSW – Port Macquarie augmentations																		
Without Directlink							Port Macquarie augmentation											
With Directlink							Directlink		Port Macquarie augmentation									

Table 7.7 DJV's view of the expected reliability failures and augmentations with Directlink (medium growth)

Loss of line	Date of contingency arising	Reliability failure	Required augmentations	Expected commissioning date
Queensland				
Line 805 or 806	2006–07 summer	Voltage stability limits exceeded within the Gold Coast network.	Greenbank augmentations	2006–07 summer
NSW				
Line 89	2017–18 summer	Voltage regulation limits exceeded at Lismore and/or line 966 or line 967 overloaded.	Dumaresq line	2017–18 summer
Glen Innes–Tenterfield line	2017–18 summer	The Tenterfield–Lismore line 132 kV line expected to be decommissioned during construction of the Dumaresq line. Without this line, Tenterfield serviced by only one line and Country Energy unable to meet its network reliability obligation to Tenterfield.	Tenterfield line or substation	2017–18 summer
Line 965 or line 96C and line 96G	2004 winter	Voltage regulation limits reached and customers exposed to low voltage conditions in the Coffs Harbour, Kempsey and Port Macquarie areas.	Port Macquarie augmentations	2010–11 summer

Submissions and the consultancy report

Queensland—Greenbank augmentations

Powerlink confirmed that it relies on Directlink during peak periods for network support. It has a network support agreement with DJV for this purpose.

New South Wales—line 966

On 11 March 2005, TransGrid wrote to the ACCC in response to its queries. TransGrid stated that there is a risk at times of high summer demand that line 966 may be overloaded. However, it also stated that:

> At present, limitations within the Queensland network supplying the Gold Coast mean that Directlink cannot be relied upon to support the New South Wales north coast at these times.

> Consequently, at this stage TransGrid cannot rely on support from Directlink at peak load times. Directlink may be able to provide network support to NSW at times when the Queensland load is lower than peak levels.[94]

In its letter to the ACCC on 6 April 2005, DJV argued that the Greenbank augmentations and additional augmentations planned by Powerlink are expected to relieve the limitations within the Gold Coast network. It stated:

> BRW has made a reasoned prediction of the likely outcome of the current joint planning process that will determine the transmission reinforcement projects necessary to meet the demands of the Tweed area in coming years. The same augmentations will provide the capacity needed for Directlink to provide firm network support into the Lismore area. While the joint planning process may in the end choose a different augmentation and timing to that BRW has predicted, the augmentation chosen will increase Powerlink's capacity to supply the Tweed area and alleviate capacity constraints to the north of Directlink in response to the actual rate of load growth in the area.[95]

In response to TransGrid's statement that constraints in southern Queensland (the Gold Coast/Tweed area) mean Directlink cannot be relied on to provide support during peak load conditions, DJV stated:

> The TransGrid letter appears to describe a network scenario where, under peak load conditions, Line 966 is overloaded following an outage of Line 89 and at the same time, Directlink's southward flow is constrained by supply conditions in Queensland where Powerlink's network would be unable to provide full capacity to Directlink. The Directlink Joint Venturers consider that the probability of these events occurring coincidentally is highly unlikely.[96]

TransGrid stated that it could not rely on Directlink to substitute for the uprating of line 966 and that it would complete the uprating by the summer of 2006–07. This uprating would relieve the thermal constraint being reached on line 966 in the contingency of an outage on line 89. TransGrid stated that it could not rely on Directlink because constraints in the southern Queensland network would prohibit the flow of power south across Directlink during times of peak load in southern Queensland. It stated that far north NSW and southern Queensland typically experience coincident peaks, given their geographic proximity. Consequently, TransGrid cannot, for network planning purposes, rely on Directlink to flow power south to provide support to the far north coast of NSW during peak conditions. Although NEMMCO could direct Directlink to flow south, TransGrid stated that such a decision would depend on circumstances at the time, which TransGrid could not rely on for planning purposes.

TransGrid stated that the completion of the Greenbank augmentations and further augmentations to the southern Queensland network are expected to relieve the Queensland constraints. While the Greenbank augmentation is scheduled for completion before the summer of 2006–07, the timing of further augmentations to the southern Queensland network is subject to joint planning processes; the augmentations are expected to be completed by the summer of 2007–08. The timing of these plans is too uncertain, however, for TransGrid to rely on power flowing

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94 TransGrid, Letter to the ACCC, op. cit., p. 3.
95 DJV, *Submission in Response to Letters from TransGrid and PB Associates*, op. cit., pp. 4–5.
96 ibid., pp. 5–6.

south across Directlink to provide network support during peak conditions on the far north coast of NSW and in southern Queensland before 2007–08. Consequently, TransGrid intends to uprate line 966 by the summer of 2006–07. Once the augmentations to the southern Queensland network are completed around the summer of 2007–08, TransGrid intends to rely on Directlink, in conjunction with the uprated line 966, to defer construction of the Dumaresq–Lismore 330 kV line.

Powerlink confirmed a number of TransGrid's statements, stating that it had entered a network service agreement with DJV in response to limited power supply to southern Queensland. Powerlink expected southern Queensland and the far north coast of NSW to have coincident peaks and conducted its network planning under this assumption. Due to constraints in the southern Queensland network, it did not expect Directlink to be able to flow power south during such a peak in the summer of 2005–06. Upon completion of the Greenbank augmentation in time for the summer of 2006–07, Powerlink expected that remaining limitations in the southern Queensland network would still restrict the ability of Directlink to flow power south. Augmentations to relieve these limitations have been the subject of joint planning, and construction is expected to be completed by the summer of 2007–08.

Country Energy stated that Powerlink had proposed assigning a higher rating to the Mudgeeraba–Terranora lines to increase the continuous capacity on the lines by roughly 10 per cent. In light of this re-rating, BRW stated that constraints in southern Queensland would not limit the capacity of Directlink to flow power south during the summer of 2006–07. Powerlink confirmed that it has proposed assigning a higher rating to the Mudgeeraba–Terranora lines, but noted that the rating will be an emergency rating and not sustainable over long periods. It also noted that the ability for Directlink to flow power south in 2006–07 after the re–rating may still be limited by transformer capacity at Molendinar and constraints within Energex's network on the southern Gold Coast. However, Powerlink has not conducted detailed studies and could not confirm the exact constraints and the conditions under which they would arise.

On 5 July 2005, DJV wrote to the AER about the transformer capacity at Molendinar. It stated that Powerlink had informed it that a second 275/110 kV transformer could be installed in time for the summer of 2006–07. The transformer is already available as a spare and can be installed when other work is conducted at the Molendinar substation. DJV argued that the installation of a second transformer by late 2006 would ensure the Gold Coast and Tweed networks have sufficient capacity for Directlink to flow power south in the summer of 2006–07 and thus permanently defer the need for TransGrid to upgrade line 966.

Powerlink responded on 15 July 2005 to a letter from the AER seeking confirmation of DJV's statements. It stated that it has recommended a second transformer be installed at Molendinar by 2007–08, not 2006–07 as asserted by DJV. The spare transformer is located at Molendinar and, with other substation work being committed; Powerlink has the opportunity to advance the installation of the transformer if it is economic to do so. However, this will not change constraints on Directlink's capacity to flow power south because the transformer will be unable to be energised simultaneously with existing plant until augmentations by Energex (scheduled for 2007–08) are completed.

On 15 September, Country Energy wrote to the AER and provided it with copies of correspondence between it and Powerlink concerning the timing of works at Powerlink's Molendinar substation. In its letter, Country Energy indicates that Powerlink has approved the installation of a second transformer at Molendinar during 2006 and that this will relieve the critical contingency in the Gold Coast and release up to 90MW of capacity for southward flow across Directlink. Country Energy states that Powerlink's revised plans for the second Molendinar transformer will alleviate the current limitations of the transmission network in northern NSW from 2006. It also states that, from that time, Directlink will have sufficient capacity to flow south to avoid load shedding, due to the overloading of TransGrid's 132kV line 966 during peak load conditions after an outage of TransGrid's 330kV line 89. A copy of Country Energy's letter and correspondence between it and Powerlink can be found on the AER's website.

New South Wales—Dumaresq line

TransGrid stated that it expects Directlink, in conjunction with an uprated line 966, to defer construction of the Dumaresq–Lismore line from the summer of 2007–08.

New South Wales—Port Macquarie augmentations

BRW stated that its load flow modelling assumed that the 330 kV augmentations to Port Macquarie will be commissioned in 2008–09 to relieve contingent low voltages and overloads. It stated that a report by PB Associates quoting studies by TransGrid indicated that this augmentation could be deferred by two years through a coordinated voltage scheme involving Directlink. BRW noted that TransGrid had reservations about such a scheme.

In a letter to the ACCC on 24 February 2005, PB Associates argued that BRW had misinterpreted its report, which had been produced to assess the capital expenditure proposed by TransGrid for the regulatory period 2004–05 to 2008–09.[97] It also argued that the augmentations required to support Port Macquarie and Kempsey are uncertain and that further modelling is needed to determine the practicality of a coordinated voltage scheme and what role, if any, Directlink would have in that scheme.

The ACCC wrote to both DJV and TransGrid requesting comments on PB Associates' letter. In particular, it informed DJV that it did not possess sufficient material to determine the extent to which Directlink can provide support and deferral of the Port Macquarie augmentations. DJV was requested to provide additional modelling of load flows and voltage conditions to support its claim. In response to the ACCC's letter, DJV requested that the ACCC consider the application on the basis of the technical information provided to date.[98] It attached a report from BRW that stated that BRW had not done detailed modelling of possible solutions to address voltage conditions at Port Macquarie.[99]

TransGrid stated that:

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97 PB Associates, Letter to the ACCC, 24 February 2005.

98 DJV, *Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue to June 2015*, Port Macquarie, 10 March 2005, p. 2.

99 BRW, *Modelling of Port Macquarie Voltage Condition*, 10 March 2005, p. 1.

> The Port Macquarie area is 'electrically' quite remote from Lismore. TransGrid does not believe that it is practicable to rely on network support in the Lismore area, from Directlink, to defer works to augment supply capacity to the mid north coast (the Kempsey/Port Macquarie/Taree area) as:
>
> - some of the works cannot be deferred by network support in the Lismore area;
> - it is not certain that the necessary control scheme coordinating operation of Lismore and Coffs Harbour 330/132 kV substations can be practically implemented;
> - it is likely that unexpectedly high load growth on the mid north coast will advance the date at which an augmentation is required, and
> - the lead-time available to complete the work required to maintain reliability standards on the mid north coast is of concern.[100]

TransGrid elaborated on its concern with the control scheme:

> At this stage it is not certain that the control scheme with acceptable reliability will be able to be practicably implemented and it would be unwise to assume that it can. If it cannot, the need to augment supply to the mid north coast is extremely pressing.[101]

Deferral period end point

PB Associates recommended that Directlink's deferral period end point be considered up until 2014–15. It stated that TransGrid had undertaken detailed planning for only 10 years and that many uncertainties exist regarding other scenarios beyond this period.

TransGrid stated that ongoing joint planning with Powerlink has confirmed that sufficient capacity from the north is available for Directlink to effectively provide network support to NSW up to at least 2012.[102] Joint planning has not progressed past 2012 at this stage, and TransGrid cannot comment on Directlink's capacity to provide network support services to NSW beyond that time.

DJV responded to PB Associates' report by stating that BRW has estimated the long term deferral benefits of Directlink (and its alternative projects) on the basis of the best currently available information, and by considering likely network development and load growth scenarios. The long term benefits are highly likely to fall within a range defined by the low, medium and high growth cases, and will not be zero.

DJV went on to state that:

> There is no sound reason for ACCC to determine that the long-term deferral benefits of Directlink's alternative projects are zero, especially given the significant financial impact such an arbitrary view could impose upon the Directlink Joint Venturers.
>
> Based on a reasonable extrapolation of the best currently available information, Alternative 0/1/2 can be expected to defer the need for the 330 kV Lismore to Dumaresq line from 2007

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[100] TransGrid, Letter to the ACCC, op. cit., p. 4.

[101] ibid., p. 4.

[102] id., *Submission—PB Associates Report on DJV Revised Conversion Application*, Port Macquarie, 14 January 2005, p. 1.

for 10 years in the expected load growth case. If the deferral period was reduced from 10 to 7 years, it would reduce the network deferral benefits of Alternative 0/1/2 by $18.5m.[103]

The AER's considerations

Queensland—Greenbank augmentations

The AER has considered the views of BRW, PB Associates and Powerlink. It appears reasonable that Directlink can defer the Greenbank augmentations by one year for the summer of 2005–06. Further, DJV has a network support agreement with Powerlink that demonstrates that Directlink is deferring the Greenbank augmentations by one year.

New South Wales—line 966

Given that Directlink is required to provide network support to Queensland for the summer of 2005–06, the constraints in the southern Queensland system would mean that Directlink cannot flow power south to support the northern NSW network for the summer of 2005–06. Powerlink and TransGrid indicated that no power will be available in southern Queensland to flow south across Directlink if a coincident peak occurs in the far north of NSW and southern Queensland. In these circumstances, there is strong evidence that Directlink cannot be relied on to flow power south during the summer peak of 2005–06.

There is also considerable uncertainty about the ability of Directlink to flow south and defer augmentations in the far north coast of NSW for the summer of 2006–07. After the Greenbank augmentation is completed for the summer of 2006–07, some power will be available in the southern Queensland network (the northern part of the Gold Coast). Despite the Greenbank augmentation, however, constraints in the southern Gold Coast network are expected to limit the ability of Directlink to flow power south for the summer of 2006–07. Both Powerlink and TransGrid indicated that such constraints exist, but they have not performed studies to ascertain the exact impact of these constraints.

Powerlink, TransGrid and BRW stated that as yet undefined works around the summer of 2007–08 are expected to alleviate a constraint on the Mudgeeraba–Terranora lines (although the exact timing remains uncertain). The need to upgrade the transfer capacity between Mudgeeraba and Terranora is driven by load growth in the Tweed area. The re-rating of the Mudgeeraba–Terranora lines is likely to reduce constraints on those lines to some extent and provide some transfer capacity for Directlink to flow south under contingency conditions from 2006–07. However, this is only a partial solution and additional work is required to provide the necessary capacity.

While there is some uncertainty surrounding the nature and timing of these additional works, there is reason to believe that the constraints will be substantially relieved by 2007–08. From the summer of 2007–08, the AER considers it can reasonably expect power to be available in the southern Queensland network to sufficiently flow south across Directlink to support the far north coast of the NSW network, thus deferring the requirement to construct the Dumaresq–Lismore 330 kV line.

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[103] DJV, *Submission in Response to PB Associates Report*, op. cit., p. 24–5.

While BRW demonstrated a theoretical potential for Directlink to flow power south during this interim period (that is, for the summer of 2006–07), Powerlink and TransGrid have raised concerns and potential obstacles. It is not clear, for example, that the re-rating will provide sufficient power in southern Queensland to flow south across Directlink. Further, Powerlink is uncertain about the impact of transformer capacity at Molendinar and the impact of load growth on power transfer capacity within Energex's southern Gold Coast network.

DJV claimed that a second transformer at Molendinar could be installed for the summer of 2006–07 and provide additional capacity to flow south across Directlink into NSW and avoid the need to upgrade line 966. Country Energy had requested Powerlink to bring forwards the installation of a second transformer in time for the summer of 2006–07. Country Energy also proposed that Powerlink consider an automatic changeover scheme to overcome limitations in Energex's network associated with energising both transformers at the same time. Powerlink recently confirmed that it would install the second transformer for the summer of 2006–07. However, it considered the automatic changeover scheme would be of limited benefit relative to the cost.

Previously, however, Powerlink indicated that it had no plans to advance procurement of a replacement spare transformer; the second transformer at Molendinar would remain as the system spare until 2007–08 and could be relocated if another similar transformer failed before that time. Further, the AER understands that even if the transformer is made available for service in the summer of 2006–07, limitations in the Energex network would prevent it from being used at the time. Augmentations to the Energex network are required by 2007–08 to allow both transformers to be simultaneously energised for operation.

It is not certain that the installation of a second transformer without advancement of other investments (namely, Powerlink's purchase of a replacement spare transformer and augmentations to the Energex network in the Gold Coast area) would provide any additional capacity for power to flow south across Directlink during the summer of 2006–07. In light of these uncertainties, CHC Associates advised the AER that it is reasonable for TransGrid to not rely on Directlink to alleviate constraints in the far north coast of NSW during the summer of 2006–07. In addition, the AER notes that:

- in finalising TransGrid's 2004–05 to 2008–09 revenue cap decision, on the basis of the information available at that time, the ACCC considered that it was appropriate to provide TransGrid with an allowance for the uprating of line 966[104]

- TransGrid's 2005 annual planning report indicated that the preferred option is to uprate line 966.

For this draft decision, the AER considers that it is reasonable for TransGrid to minimise the risk to its network by uprating line 966 to alleviate its network reliability problems in the NSW north coast area. Accordingly, no deferral of the uprating of line 966 is attributed to Directlink.

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[104] ACCC, *NSW and ACT Transmission Network Revenue Cap: TransGrid 2004–05 to 2008–09*, Canberra, 27 April 2005, p. 111–12.

The AER notes that it received further information on this issue from Country Energy late in the development of this draft decision. As such it did not have sufficient time to undertake consultation on this material before finalising its decision. Instead the AER proposes to consult with interested parties on this information as part of the draft decision consultation period and to incorporate its findings into the final decision. The information received from Country Energy can be found on the AER's website and interested parties are invited to make submissions on this issue as part of their submission on the AER's draft decision.

New South Wales—Dumaresq line

The AER has considered the views of interested parties. While there is some uncertainty about the ability of Directlink to flow south into the north coast of NSW during the summer of 2007–08, based on the available information the AER accepts that Directlink can defer construction of the Dumaresq–Lismore 330 kV line from the summer of 2007–08.

New South Wales—Port Macquarie augmentations

The AER has been advised by its engineering consultant (CHC Associates) that Directlink cannot have any effect on constraints in Port Macquarie until after the third stage of the NSW mid north coast augmentations. TransGrid's annual planning report referred to this third stage (that is, operating a second 132 kV (330 kV construction) line between Kempsey and Port Macquarie), which is a part of the works claimed to be deferred by Directlink. The contingent outage of the existing Kempsey – Port Macquarie line is the reason for needing the augmentations, and there is no path before these works for Directlink to direct power flow into Port Macquarie during the outage.

Regarding the future 330 kV line and 330/132 kV substation works foreshadowed by TransGrid, the AER was advised that the special control scheme will apply to only one of the contingencies that will influence the timing of these works—namely, the outage of the Armidale – Coffs Harbour 330 kV line. Directlink is distant from Kempsey and Port Macquarie, however, and would be unlikely to have any significant influence on voltage control at these locations. For outages of the Armidale–Kempsey or Kempsey – Port Macquarie 132 kV lines, the normal voltage control facilities prevent Directlink having any effect south of Coffs Harbour.

The AER considers that:

- DJV has not provided sufficient information to support its proposition that Directlink can defer the Port Macquarie augmentations
- the advice from its engineering consultant and TransGrid is reasonable. Directlink appears unlikely to provide any deferral benefits for the Port Macquarie augmentations.

Deferral period end point

The AER has considered the comments of DJV and TransGrid on the deferral period end point of Directlink, as well as PB Associates' recommendation. The market generally does not forecast and plan in detail beyond a 10 year period, and the AER acknowledges the uncertainty over Directlink's ability to provide long term deferral benefits.

However, BRW's load modelling, which demonstrated that Directlink can provide network support to NSW until 2017–18 (medium growth scenario), appears to be reasonable. The deferral benefits beyond 2014–15 would not be expected to be zero, and are likely fall within a range defined by the low, medium and high growth scenarios. The AER will thus adopt BRW's proposed end point deferral period of Directlink, and the relevant deferral benefits will be calculated on that basis.

Conclusion

Table 7.8 summarises the AER's view of the altered timing for required augmentations to address contingency events and potential failures to meet reliability standards, in the 'with Directlink' case.

Table 7.8 The AER's view of expected reliability failures and augmentations with Directlink (medium growth)

Loss of line	Date of contingency arising	Reliability failure	Required augmentations	Expected commissioning date
Queensland				
Line 805 or 806	2006–07 summer	Voltage stability limits exceeded within the Gold Coast network.	Greenbank augmentations	2006–07 summer
NSW				
Line 89	2003–04 summer	Line 966 overloaded.	Line 966	2006–07 summer
Line 89	2017–18 summer	Voltage regulation limits exceeded at Lismore and/or line 967 overloaded.	Dumaresq line	2017–18 summer
Glen Innes–Tenterfield 132 kV line	2017–18 summer	The Tenterfield to Lismore line 132 kV line expected to be decommissioned during construction of the Dumaresq line. Without this line, Tenterfield serviced by only one line and Country Energy unable to meet its network reliability obligation to Tenterfield.	Tenterfield substation	2017–18 summer
Line 965 or line 96C and line 96G	2004 winter	Voltage regulation limits reached and customers exposed to low voltage conditions in the Coffs Harbour, Kempsey and Port Macquarie areas.	Port Macquarie augmentations	2008–09 summer

Figure 7.8 illustrates the AER's view on the impact of the revised timing on the expected reference case augmentations, in the 'with Directlink' case.

Figure 7.8 The AER's view of expected deferral timing of the reference case with Directlink (medium growth)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec
Queensland																		
Reference case				Greenbank augmentation														
With Directlink				D/L	Greenbank augmentation													
NSW – Line 966																		
Reference case					Line 966													
With Directlink					Line 966													
NSW – Dumaresq line																		
Reference case						Dumaresq												
With Directlink						Directlink										Dumaresq line		
NSW – Tenterfield																		
Reference case						Tenterfield substation												
With Directlink						Directlink										Tenterfield		
NSW – Port Macquarie augmentations																		
Reference case							Port Macquarie augmentation											
With Directlink							Port Macquarie augmentation											

7.4.2 Economic benefits attributed to Directlink's deferral of the reference case

DJV's application

BRW estimated the economic value of Directlink's transmission network deferral benefits as being $137.5 million (based on a 9 per cent discount rate and a medium growth forecast).[105]

Submissions and the consultancy report

Availability of Directlink

PB Associates stated that it has been provided with historical outage statistics for Directlink, and that its analysis reveals the availability calculation (based on available active power capability) has been around 80 per cent over the past 23 months. It noted that many of the benefits associated with Directlink (including deferral benefits) depend on full or close to full active and reactive power capability being available. It has assumed an availability of at least 99 per cent for 120 MW (that is, for two of the three HVDC Light modules) in its estimates for deferral of the reference case. PB Associates stated that extended outages would reduce this availability and significantly reduce Directlink's capability to provide benefits.

DJV stated that it is mindful of its code obligations on conversion to maximise Directlink's availability, and that it is committed to implementing equipment upgrades to ensure Directlink's availability is around 99 per cent. DJV further noted that:

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105 BRW, *BRW Draft Explanation to Review of Costs and Deferment Benefits*, op. cit., p. 4.

> Flows across Directlink are greatly influenced by wider network constraints at peak load—as described in the BRW report—even during periods of regional price difference. At peak load, Directlink is typically constrained to around 120 MW. BRW and TEUS [TransÉnergie US Limited] have taken this into account when estimating network deferral and interregional benefits of Alternative 0. They have, in fact, assumed that peak load transfer limits apply continually and this indicates that BRW and TEUS's estimates incorporate a significant level of conservatism.[106]

Deferral value of Queensland augmentations

PB Associates stated that Powerlink has contracted with DJV to provide network support if lines 805 or 806 are lost for the 2005–06 summer period. This support will allow the deferral of the 275 kV Greenbank switchyard and a new double circuit 275 kV line linking the Greenbank and Molendinar substations for one year. PB Associates stated that the deferral benefits of the Queensland augmentations could be based on the estimated value of $2.7 million for the commercial network support agreement between DJV and Powerlink.

In response, DJV stated that measuring the deferral benefit using the value of the network support agreement contravenes the regulatory test. It stated that the payment under the network support agreement is a wealth transfer rather than an economic benefit to all those who produce, consume and transport electricity as a whole.

The AER's considerations

Availability of Directlink

DJV indicated that the historical availability of Directlink for forced outages has been 80.9 per cent. The AER has received from DJV a confidential consultant's report that reviewed the upgrades necessary to improve Directlink's reliability. While the report indicated that Directlink's reliability can be improved to around 99 per cent, the author expressed some uncertainties. The AER notes that the program of upgrades being undertaken by DJV is targeted for completion towards the end of 2005. It is uncertain whether Directlink can achieve the reliability required to generate the market benefits attributed to it. Consequently, the deferral benefits ascribed to Directlink are likely to be below those proposed by DJV.

The AER considers that it is somewhat doubtful whether Directlink can achieve an availability of 99 per cent. For the regulatory test assessment, however, it will assume a reliability of at least 99 per cent for the technical requirement of 120 MW; it considers that the deferral benefits ascribed to Directlink should be regarded as a maximum. In addition, the cost of the upgrades to improve Directlink's reliability will be excluded in the revenue cap because 99 per cent reliability has been assumed for the determination of the deferral benefits.

Deferral value of Queensland augmentations

The AER has considered PB Associates' proposal but will value the deferral benefit for the Queensland augmentations using the difference between the present value of the costs of the augmentation based on different timing scenarios (the with and without Directlink cases). This approach is consistent with the intended principles of

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[106] DJV, *Submission in Response to PB Associates Report of 26 November 2004*, op. cit., p. 27.

the regulatory test, which focus on the increases in economic efficiency represented by increases in total welfare.

If, however, Directlink converts to a prescribed service after payments have been made to DJV under the network support agreement with Powerlink, then the payments should be subtracted from the estimated value of the deferral benefit for the Queensland augmentations. This will ensure customers do not pay twice for the deferral of the Queensland augmentations.

Conclusion

Based on the timing of the required augmentations to address network reliability standards in the 'with Directlink' case, the AER considers the economic value for the deferral of transmission augmentations is as shown in table 7.9 (based on a 9 per cent discount rate and a medium growth forecast). It has reviewed DJV's model for calculating the deferral benefits. For this regulatory test assessment, it has adjusted the NPV formula to align the expected timing of the reference case augmentations (which occur by the summer peak period corresponding to 1 December) with Directlink's assumed commissioning date of 1 July 2005.

Table 7.9 The AER's conclusion on the expected deferral benefit with Directlink ($ million, 1 July 2005)

	Present value of:		
	Costs under the reference case	**Costs in the presence of Directlink**	**Deferral benefit**
Greenbank augmentation	67.6	62.0	5.6
Dumaresq line	142.6	59.9	82.7
Tenterfield substation	12.6	5.3	7.3
Total	222.8	127.2	95.6

7.5 The 'with alternative projects' case

Appendix F contains the AER's consideration of the network augmentation deferral benefits provided by the alternative projects. In summary, table 7.10 shows that alternatives 1 and 2 provide the same network deferral benefit as would Directlink (based on a 9 per cent discount rate and a medium growth forecast).

Table 7.10 The AER's conclusion on the expected deferral benefit with alternatives 1 or 2 ($ million, 1 July 2005)

	Present value of:		
	Costs under the reference case	Costs in the presence of alternative project	Deferral benefit
Greenbank augmentation	67.6	62.0	5.6
Dumaresq line	142.6	59.9	82.7
Tenterfield substation	12.6	5.3	7.3
Total	222.8	127.2	95.6

For alternative 3, the economic value for the deferral of transmission augmentations is as shown in table 7.11 (based on a 9 per cent discount rate and a medium growth forecast).

Table 7.11 The AER's conclusion on the expected deferral benefit with alternative 3 ($ million, 1 July 2005)

	Present value of:		
	Costs under the reference case	Costs in the presence of alternative project	Deferral benefit
Dumaresq line	142.6	110.0	32.6
Tenterfield substation	12.6	9.7	2.9
Total	155.2	119.7	35.5

8 Interregional transfer benefits

8.1 Introduction

Increased interconnection alters the distribution of electricity flows across the national electricity market (NEM). Benefits to market participants may accrue to the extent that the altered distribution of electricity flows reduces the cost to market participants of generating and supplying electricity.

The market benefit of interregional power flows is represented financially as the difference between the present value of the capital and operating costs of energy supply in the NEM:

- ‘without Directlink’ providing an interconnection between Queensland and NSW
- ‘with Directlink’ (or one of its alternative projects).

The purpose of this chapter is to estimate the benefits to market participants due to the additional interregional power transfer in the ‘with Directlink’ case (or one of its alternative projects). The remainder of this chapter sets out the background (section 8.2), the AER’s considerations of DJV’s application, submissions and consultants’ reports on:

- the interregional benefits modelling (section 8.3)
- the ‘without Directlink’ case (section 8.4)
- the ‘with Directlink’ case (section 8.5)
- the ‘with alternative projects’ case (section 8.6).

8.2 Background

Estimating the interregional market benefits can be a more subjective process than evaluating the transmission network augmentation deferral benefits. The reasonableness of the network deferral benefits attributed to Directlink and its alternative projects can be gauged against the augmentation plans and advice from the relevant transmission network service providers (TNSPs). Further, the network deferral benefits occur in a more immediate time frame. By contrast, estimation of the interregional benefits requires assumptions and projections of the expected behaviour and costs of the entire NEM over a time horizon of up to 40 years. A wide range of outcomes are possible under different assumptions and projections. To provide confidence that the estimated interregional benefits are realistic, the reasonableness of both the method and the input assumptions used to derive those estimates should be compared to actual market behaviour in the NEM. Particularly important are:

- the assumptions used to model bidding strategies in the market
- the interregional transfer limits proposed by BRW for the ‘without Directlink’ and ‘with Directlink’ cases.

8.3 Interregional benefits modelling

8.3.1 DJV's application

DJV engaged TransÉnergie US Limited (TEUS) to estimate the net present value (NPV) of the interregional benefits provided by Directlink or its alternative projects. TEUS used two models to estimate the interregional benefits:

1. the PROSYM Chronological Production Modelling System (PROSYM)

2. the General Electric Multi-Area Reliability Simulation (MARS).[107]

It used PROSYM to develop a sequential hourly model of the regional distribution and costs of generation in the NEM over time. This model represented the five price regions of the NEM, but was simplified to the extent that some network constraints were represented by typical values rather than values that vary with system conditions. Further, some intra-regional network constraints that are not relevant to assessing the impact of Directlink and its alternative projects were excluded.

TEUS estimated the expected distribution of generation and demand across this model of the NEM using forecasts applied to historical regional demand, and the locations and bidding of generators. It used the expected supply and demand for electricity to model the expected prices of electricity in the five price regions. Looking forwards, to the extent that expected prices in a NEM region allow the profitable entry of a generator (using one of several types of generation), a new generator of that type was assumed to be commissioned and remain available from that year forward.

A model of the likely location and costs of generation in the NEM over time was developed for the 'without Directlink' case and the 'with Directlink' case. All other variable elements of the two models, such as existing and planned generation and emergency outages, were aligned to isolate the cost difference that could be ascribed to Directlink. TEUS used the resulting models of the expected distribution of demand and generation in the NEM as inputs into the MARS model. The MARS model provides a more detailed model of the incidence of unserved energy (USE).

NEMMCO, until 1 July 2006, contracts with market participants for the provision of electricity to meet expected demand in a region of the NEM beyond that region's capacity. It does this to ensure reliability of supply meets standards set by the Reliability Panel.[108] The current reliability standard requires USE to be less than or equal to 0.002 per cent of annual customer demand in each region.[109] TEUS assumed this 'reserve trader' provision to be extended indefinitely. If the MARS model were to indicate that the reliability standard had not been met, reliability plant would be added to the model in the deficient region, and the generic costs of this plant would

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107 TEUS, *Estimation of Directlink's Alternative Projects' Interregional Market Benefits*, Westborough, April 2004, pp. 8–9.

108 National Electricity Code, clause 3.12.1(a).

109 National Electricity Code Administrator (NECA), *Reliability Panel: Determination on Reserve Trader and Direction Guidelines*, Adelaide, 2 June 1998, pp. 2, 9.

be estimated. To the extent that residual USE was less than that allowed by the standard, this was costed at an estimate of the cost of USE.

In the PROSYM and MARS models, TEUS made the following key assumptions:

- Generators bid electricity into the NEM at a proxy cost for the long run marginal cost (LRMC), which is represented by the short run marginal cost (SRMC) plus $20 per megawatt hour (MWh). The SRMC is indicated in a NEM generator costs report by ACIL Tasman (the 2003 ACIL Tasman report) for NEMMCO and the Inter-Regional Planning Committee (IRPC).

- The appropriate discount rate for the regulatory test is 9 per cent.

- Existing and committed generation includes that indicated by NEMMCO’s 2003 *Statement of Opportunities* (the 2003 SOO).

- The characteristics of existing, committed and new generation are those indicated in the 2003 ACIL Tasman report, the 2003 SOO and the 2003 *Annual Interconnector Review*.

- All costs are inflated by the consumer price index.

- The value of USE is $29 600 per MWh as developed by VENCorp as an approximation of the value of customer reliability.

- A simplified model or topology of the NEM includes seven regions for the PROSYM modelling and 13 regions for the MARS modelling

- Constraints on flows among these regions are defined by BRW’s report on the selection and assessment of alternative projects.

- Forecast hourly load traces for the subregions use loads and forecasts published in the 2003 SOO, Powerlink’s 2003 annual planning report and TransGrid’s 2003 annual planning report.

- The modelling period is for 40 years from 1 July 2005.

- Interregional market benefits for the period 1 July 2019 to 30 June 2045 reflect an average of those modelled for five different termination years between 2015 and 2019.

8.3.2 Submissions and the consultancy report

The ACCC engaged Intelligent Energy Systems (IES) to evaluate TEUS’s modelling of the interregional benefits. IES evaluated the assumptions and inputs used in TEUS’s modelling, rather than duplicating the modelling that TEUS undertook. It noted that the outcomes of aspects of TEUS’s modelling are inconsistent with observed market dynamics—in particular:

- the unrealistic spot price outcomes in the market modelling would have a significant impact on the dynamics of new entry generation

- bids modelled (by PROSYM) were inconsistent with those historically observed in the NEM
- price levels reached during the modelling period were above those generally considered necessary for economic entry of plant
- the fixed cost component of LRMC ($20 per MWh) was higher than the annualised fixed cost of many generator unit types
- unsupported assumptions were used for new entry costs
- the service level provided by Directlink (and its alternative projects) assumed that it increases the interconnection capacity from NSW to Queensland in the PROSYM modelling, when this is not the case
- the level of market generation deferral does not accord with the service level provided by Directlink (and its alternative projects)—for example, the modelling had 200 MW of market entry deferral in Queensland when Directlink does not provide any increase in interconnection capacity to Queensland
- since the time of the modelling by TEUS, market developments have occurred that would result in significant changes to assumptions.[110]

IES considered that these issues would have a significant impact on the value of the interregional benefits.[111] As a result of these observations, it advised the ACCC not to rely on TEUS's modelling for this regulatory test assessment.

TXU supported IES's comments on TEUS's modelling assumptions:

> … TXU welcomes the ACCC's exercise of critiquing the value of the inter-regional benefits that have been claimed by the Direct-Link Joint Venture on the basis that regulatory test has not been applied in accordance with Sect. 5.6.5(a) of the Code. TXU supports the ACCC on the following issues;
>
> - The review of the modelling assumptions that reduce the benefits to Direct-Link if the project does not provide any northward flow.
> - The review of the modelling assumptions that change inflated the unrealistic spot price out turns given that they would significantly impact the dynamics of new entry generation and associated benefits that inflate the interregional benefits.
> - The review of the modelling assumptions that use unsupported assumptions on new entry costs that inflate the interregional benefits. [112]

In response to IES's report, TEUS stated that the use of bidding that reflects historically observed prices is inconsistent with the ACCC's approach in the Murraylink decision and is unlikely to replicate actual market outcomes.[113] It stated

[110] IES, *Directlink Conversion Application—Review of Interregional Market Benefits*, Melbourne, 26 April 2005, pp. 37–41, 51, 65–7, 73.

[111] ibid., p. 66.

[112] TXU, *TXU's Submission to Intelligent Energy System's (IES) Review of the Interregional Market Benefits of Directlink*, Melbourne, 24 May 2005, pp. 1–2.

[113] TEUS, *Response to the IES Final Report: Reviewing Directlink's Alternative Projects' Interregional Market Benefits*, Westborough, 16 May 2005, pp. 10–11.

that the use of LRMC creates an upper bound of the likely results from actual bidding behaviour and, in conjunction with SRMC, creates the range of likely results from actual bidding behaviour. TEUS also stated that use of historical bidding assumes that bidding patterns remain unchanged despite inevitable changes in the NEM. Use of historical bidding could not be expected, therefore, to produce a highly accurate estimate of the interregional benefits.

DJV argued that the assumed LRMC bidding is appropriate for the purposes of the regulatory test and consistent with the ACCC's Murraylink decision. However, it agreed to have TEUS undertake additional modelling to address the above issues raised by IES. TEUS undertook this modelling using the PROSYM and MARS models and making the assumptions identified in section 8.3.1. It adopted the following revised assumptions:

- that generators bid in the NEM at prices that reflect historically observed prices
- the use in PROSYM of network topology and interregional transfer limits incorporating northern NSW as a separate region to model Directlink's service level and to determine the market entry benefits
- existing and committed generation, including that indicated by NEMMCO's 2004 *Statement of Opportunities* (2004 SOO) rather than the 2003 SOO
- the characteristics of new generation entry cost indicated in the *Report on NEM Generator Costs (Part 2)* by ACIL Tasman in February 2005 for NEMMCO and the IRPC, rather than the 2003 ACIL Tasman report.

The ACCC engaged IES to perform similar interregional modelling using IES's PROPHET model, based on the agreed revised assumptions. The purpose of this modelling was to provide a basis for comparison with TEUS's additional modelling. Despite differences in the models, IES considered that the outcomes of the modelling should be comparable, provided the same assumptions were adopted. Section 8.5 contains a detailed discussion.

8.3.3 The AER's considerations

The regulatory test requires that prices used should reflect a range of market outcomes, ranging from SRMC bidding behaviour to simulations that approximate actual market bidding and prices. Without contracting, the SRMC is theoretically the lowest price that generators would bid into the NEM: a price sufficient to cover the marginal cost of generating electricity, but not the long run cost of their capital investment (that is, not their LRMC). When there is an equilibrium level of generation in the market, generators will recover their LRMC through the difference between their SRMC bid and the price set by the NEM. This price generally reflects the SRMC of the marginal generator that will meet the level of demand in the market at that point in time. This is the bidding behaviour that would be expected in a perfectly competitive market. Bidding above and below the SRMC, however, is observed in the NEM.

TEUS proposed the LRMC as an upper bound to the likely bidding behaviour, but the LRMC is not bidding behaviour that is observed in the market. The LRMC is not informative of observed bidding behaviour because generators need not bid at the LRMC to recover their LRMC. Generators can recover their LRMC through the difference between the SRMC of generating and the price set by the NEM. They need not recover a fixed portion of their LRMC each time they generate. The final price in the NEM may be such that generators recover a small portion of their fixed costs at some points in time and a larger portion other times. In a competitive market, generators would bid below the LRMC, given the competitive threat of others entering the market.

Instead, the LRMC is relevant to whether a new entrant chooses to build plant and generate electricity in the NEM. Such a proponent of a new generator would build only if it expected to recover the LRMC of its investment over the life of its investment. To the extent that such a proponent would not expect to recover its LRMC through the difference between its expected SRMC and the expected prices in the NEM, the generator would not be built. This would reflect the risk of investing in generation plants.

The IES advice that the prices generated by TEUS's modelling appear inconsistent with those historically observed in the NEM, and are above those generally considered necessary for new entry in the NEM, appears reasonable. Also reasonable is the IES advice that the LRMC bid price of $20 over the SRMC is higher than that generally considered necessary for the economic entry of plant into the NEM. The $20 fixed cost component over the SRMC is arbitrary. Although TEUS argued that it used modelling to determine a reasonable price that would allow for market entry, it has not provided evidence to support its arbitrary assumption. Higher prices should lead to more generation entry, but this does not establish that the modelled prices reflect those likely to be observed in the market.

TEUS's reasoning that historical prices may not generate a highly accurate measure of the interregional benefits appears reasonable. The future development of the NEM could cause prices to deviate from those historically observed, but this problem is common to all the assumptions used to estimate the market benefits of Directlink. Load growth, future augmentations, the emergence of new technologies, and a variety of other events could alter the interregional benefits.

In gauging the prices produced by TEUS's modelling, the regulatory test prescribes simulations that approximate actual market bidding and prices. In this case, neither the use of the LRMC nor historical bidding will provide a highly accurate measure of the interregional benefits. The AER considers, however, that the use of historical bidding is likely to provide prices that more closely approximate actual market bidding and prices. The LRMC is not observed in the NEM and, in this case, is essentially an arbitrary value.

DJV's application assumed that the LRMC is the most likely credible scenario.[114] The AER considers that the use of an upper bound as a credible scenario may distort the resulting ranking and outcomes of the regulatory test.

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[114] DJV, *Application for Conversion*, 22 September 2004, op. cit., pp. 47–8.

A similar proxy for the LRMC was used to model bidding behaviour in the Murraylink decision. However, in that modelling, all scenarios (including those using SRMC bidding) had at least one alternative project that satisfied the regulatory test (that is, that provided net market benefits greater than zero).[115] In most cases, that project satisfied the regulatory test, in terms of maximising the net market benefits, by a large margin. The outcome, therefore, was not sensitive to the assumed bidding behaviour.

By contrast, DJV's sensitivity analysis (recognising that alternative 5 is the reference case and not an alternative project) reveals scenarios whereby all the alternative projects do not satisfy the regulatory test (that is, they provide net market benefits less than zero).[116] Generally, these scenarios do not assume LRMC bidding behaviour. Directlink may satisfy the regulatory test only when bidding behaviour that represents the upper bound (LRMC bidding) of benefits is assumed. Further, the essentially arbitrary nature of the LRMC bidding may provide benefits above the upper bound. In these circumstances, it is appropriate to exercise greater care in modelling the interregional benefits. To reduce the possibility that the outcome of the regulatory test will be unrealistic, assumptions most likely to approximate actual market bidding and prices should be used.

TEUS's comment that inevitable changes in the NEM will cause future prices to diverge from those historically observed appears to be reasonable. Future price outcomes may be higher or lower. It is also reasonable to consider that assuming bidding behaviour reflecting that historically observed in the NEM will not generate a highly accurate estimate of the interregional benefits. In the Murraylink decision, the ACCC stated that:

> The Commission considers that it is inconsistent with the regulatory test to derive a 'most likely' or 'median' estimate of the gross market benefits, given that it does not make reference to such outcomes.[117]

Historical bidding remains more likely than either the SRMC or the LRMC, however, to generate prices that approximate those that will occur in the market. The results of the historical bidding scenarios indicate prices are more consistent with actual market price outcomes, compared with the price outcomes from the LRMC bidding strategy.

IES provided price duration curves (figure 8.1) based on the 2005 price outcomes that it modelled and the 2005 prices modelled by TEUS (both using historical bidding strategy), compared with recent market outcomes.[118] It concluded that both sets of modelling present a reasonable approximation of the spot price outcomes in the market.

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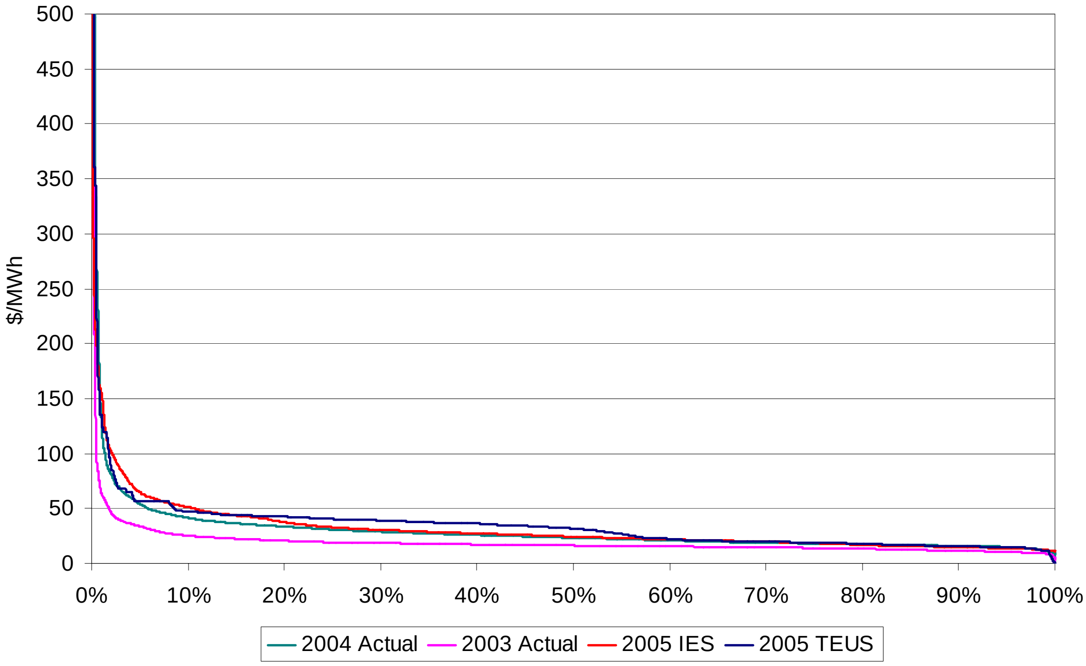
115 ACCC, *Murraylink Transmission Company Application*, op. cit., appendixes F and G, pp. 198–204.

116 DJV, *RE: Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue to June 2015*, 8 February 2005, attachment 2, p. 5.

117 ACCC, *Murraylink Transmission Company Application*, op. cit., p. 89.

118 A price duration curve is created by placing the price outcomes for a year in order from the highest to the lowest.

Figure 8.1 Price duration curves for Queensland prices



The AER will adopt TEUS's additional modelling, which assumes bidding behaviour reflecting that historically observed in the NEM. IES advised the AER that this modelling addresses the concerns raised in its consultancy report, which reviewed the original interregional benefits modelling. The revised bidding strategies used in the additional modelling will generate prices between the lower bound of the SRMC and upper bound of the LRMC. These prices are more likely to approximate actual market bidding and prices, because they reflect historical bidding and prices. Further, the possibility of a divergence of future prices from those historically observed will be explored in the sensitivity analysis for the SRMC and LRMC bidding strategies.

8.3.4 Conclusion

The AER considers that using the historical bidding assumption to model the interregional benefits is appropriate for this regulatory test assessment. TEUS's additional modelling also addresses the concerns raised by IES, particularly the incorporation of transfer limits to model market entry that are consistent with Directlink's service level.

8.4 The 'without Directlink' case

8.4.1 Transfer limits

DJV's application

In its PROSYM and MARS models, TEUS assumed a simplified network topology of the NEM. BRW estimated the transfer limits between NSW and Queensland that would typically apply during peak load conditions. It identified publicly available transfer limits and used engineering judgment to assess the impact of future augmentations on these limits. Table 8.1 summarises BRW's assessment of the transfer limits across the regions in the 'without Directlink' case.[119]

Table 8.1 DJV's proposed transfer limits without Directlink (MW, medium growth)

Year	NSW to North NSW	North NSW to NSW	North NSW to Gold Coast	Gold Coast to North NSW	North NSW to South QLD	South QLD to North NSW	South QLD to Gold Coast	Gold Coast to South QLD	South QLD to North QLD	North QLD to South QLD
2005–06 to 2008–09	1200	950	0	0	300	950	850	850	1750	1750
2009–10 to 2019–20	1200	950	0	0	300	950	1200	1200	1750	1750

Transfer across Directlink

For the 'without Directlink' case, these transfer limits exclude transfers between northern NSW and the Gold Coast—that is, transfers between NSW and Queensland across Directlink.

Transfer across the Queensland – NSW Interconnector

The only transfer between NSW and Queensland is across the Queensland–NSW Interconnector (QNI). BRW stated that the flow north on the QNI is dictated by the maximum export capability from NSW, which ranges from 400 MW to 700 MW, with transfer limits as low as 300 MW during peak summer load period. This capability is usually limited by transient/oscillatory stability, northern NSW voltage stability and NSW thermal criteria. Similarly, transfer south on the QNI is limited by transient stability (based on faults in Queensland or the Hunter Valley, or loss of the largest load in Queensland), thermal rating limits of 132 kV lines in northern NSW and oscillatory stability.

The consultancy report

Parsons Brinckerhoff Associates (PB Associates) agreed with the transfer limits proposed by BRW.[120]

The AER's considerations

Based on the information provided to the AER, the transfer limits proposed by BRW for the 'without Directlink' case appear reasonable.

8.4.2 Conclusion

The AER will adopt BRW's proposed transfer limits for the 'without Directlink' case.

[119] BRW, *Directlink: Selection and Assessment of Alternative Projects*, op. cit., p. 52.
[120] PB Associates, *Review of Directlink Conversion Application*, op. cit., p. 62.

8.5 The 'with Directlink' case

8.5.1 Transfer limits

The power transfer capability of an interconnector depends not only on the rated capacity of the interconnection, but also on:

- the design of its associated controls
- constraints within the power system that connect each end of the interconnector
- the system demand and its distribution at a particular time
- the direction of power flow.

The power transfer capability may be lower than the interconnector's rated capacity and may change with changes in the operating state of the transmission network at each end of the region.

DJV's application

Table 8.2 DJV's proposed transfer limits with Directlink (MW, medium growth)

Year	NSW to North NSW	North NSW to NSW	North NSW to Gold Coast (DL)	Gold Coast to North NSW	North NSW to South QLD	South QLD to North NSW	South QLD to Gold Coast	Gold Coast to South QLD	South QLD to North QLD	North QLD to South QLD
2005–06	1200	950	133	87	300-DL	950	650-(0.75xDL)	650	1750	1750
2006–07	1200	950	131	142	300-DL	950	850	850	1750	1750
2007–08	1200	950	129	142	300-DL	950	850	850	1750	1750
2008–09	1200	950	126	142	300-DL	950	1200	1200	1750	1750
2009–10	1200	950	124	142	300-DL	950	1200	1200	1750	1750
2010–11	1200	950	121	142	300-DL	950	1200	1200	1750	1750
2011–12	1200	950	118	142	300-DL	950	1200	1200	1750	1750
2012–13	1200	950	115	138	300-DL	950	1200	1200	1750	1750
2013–14	1200	950	113	135	300-DL	950	1200	1200	1750	1750
2014–15	1200	950	112	132	300-DL	950	1200	1200	1750	1750
2015–16	1200	950	110	129	300-DL	950	1200	1200	1750	1750
2016–17	1200	950	108	126	300-DL	950	1200	1200	1750	1750
2017–18	1200	950	107	123	300-DL	950	1200	1200	1750	1750
2018–19	1200	950	105	120	300-DL	950	1200	1200	1750	1750
2019–20	1200	950	103	117	300-DL	950	1200	1200	1750	1750

Table 8.2 summarises BRW's assessment of the transfer limits across the regions in the 'with Directlink' case.[121] These peak transfer limits were provided to TEUS to estimate the interregional benefits of Directlink (and the direct current (DC) alternative projects) associated with deferring reliability entry generation and reducing USE.

Transfer across Directlink

Directlink consists of a single alternating current (AC) cable (4 kilometres) at the northern end connected to three independent parallel high voltage direct current (HVDC) Light units and cable (59 kilometres), each designed to provide a nominal power transfer capability of 60 MW, giving it a total nominal capability of 180 MW in either direction. Losses in the converter stations and in the DC cables result in a difference between the sending and receiving ends of power transfer. Table 8.3 provides Directlink's nominal and as-tested power transfer capabilities for the sending and receiving ends.

Table 8.3 Directlink's power ratings at nominal voltage (MW)

	Sending end	Receiving end
Nominal rating	180 (3 × 60.0)	168 (3 × 56.0)
As-tested rating	188 (3 × 62.5)	175 (3 × 58.3)

At peak times, however, load flows across Directlink are influenced by wider network constraints. For north flows across Directlink, BRW stated that the transfer is dictated by:

- the continuous thermal rating of the double circuit 132 kV connection from Lismore to Mullumbimby, less the Mullumbimby and Dunoon load
- the three 132 kV lines supplying Lismore, less the combined Lismore, Mullumbimby and Dunoon load. Depending on the distribution of load growth in the region, any of the three can be the limiting factor.

For south flows across Directlink, BRW stated that the transfer is dictated by the continuous thermal rating of the double circuit 110 kV connection from Mudgeeraba to Terranora, less the Terranora load. BRW assumed that a third Mudgeeraba – Terranora/Tweed 110 kV line would be commissioned by the summer of 2006–07, which would increase the transfer limit flowing south across Directlink. It noted that the commissioning of this line has a material impact on the transfer limit south.

Transfer across the QNI

BRW stated that the maximum transfer for north flows is assumed to be a constant 300 MW that comprises both transfer on the QNI and the alternative DC links. For south flows on the QNI, BRW used the oscillatory limit of 950 MW as the nominal transfer limit.

[121] BRW, *Directlink: Selection and Assessment of Alternative Projects*, op. cit., p. 51.

Submissions and consultancy reports

Transfer across Directlink

PB Associates agreed with the transfer limits proposed by BRW for transfers across Directlink. It noted, however, uncertainty about the likelihood that the third line from Mudgeeraba to Terranora will be completed in the time assumed by BRW. If this line is not completed, PB Associates considered it likely to affect Directlink's ability to provide network support from Queensland to northern NSW.

TransGrid, Powerlink, Country Energy and DJV commented (chapter 7) on power available in southern Queensland to flow south across Directlink before the Greenbank augmentations are made and a third line is constructed from Mudgeeraba to Terranora. These comments have implications for the transfer limits described in table 8.2:

- TransGrid and Powerlink stated that prior to completion of the Greenbank augmentations for the summer of 2006–07, no power will be available in the southern Queensland network to flow south across Directlink during peak conditions in 2005–06.
- TransGrid and Powerlink expressed uncertainty about the timing of the construction of a third line from Mudgeeraba to Terranora.
- Country Energy and Powerlink stated that they have agreed to assign a higher emergency rating for the Mudgeeraba–Terranora lines. The re-rating would be increase the transfer limit (before construction of the third Mudgeeraba–Terranora line) by roughly 10 per cent to 100 MW, from the summer of 2006–07, until an unspecified longer term solution is implemented.
- Powerlink stated that the availability of power in the southern Queensland network to flow south across Directlink during the summer of 2006–07 remains uncertain given transformer capacity constraints at Molendinar and constraints within Energex's southern Gold Coast network
- On 21 September 2005, DJV stated that Powerlink confirmed its intention to bring forwards the installation of a second transformer at Molendinar to 2006–07. It claimed that the installation of the second transformer will release additional capacity to flow south across Directlink into NSW.

Transfer across QNI

PB Associates agreed with the transfer limits proposed by BRW for flows across QNI.

IES noted that TEUS's interregional benefits modelling indicated that Directlink defers 200 MW of generation in Queensland. By contrast, NSW has an additional 100 MW of generation in the presence of Directlink. IES stated that this should not be expected because the presence of Directlink does not increase the combined flow of power north across the QNI and Directlink. Any additional power flowing north across Directlink reduces the power flowing north across the QNI, such that no additional power flows into Queensland from NSW. The presence of Directlink is thus not expected to defer generation in Queensland.

IES stated that the transfer limits assumed by TEUS for the PROSYM modelling ignore the constraint from central NSW to northern NSW and allow for additional power to flow north into Queensland in the presence of Directlink. TXU supported IES's comments on the use of an inappropriate transfer limit for northward flow on Directlink.

TEUS responded to IES by stating that it had performed additional modelling of a single case, which indicated that the revised limits (which recognised the northern NSW limit) have little or no impact on the estimates of interregional benefits.[122] TEUS stated that this finding was consistent with its expectations. It further indicated that there are circumstances in which market entry in Queensland could be deferred, despite Directlink not increasing the transfer capacity north from NSW. In the presence of the QNI, lower prices in NSW (due to the south flow of Directlink) will be exported north across the QNI and Directlink. This will alter the distribution of price and entry in Queensland.

The AER's considerations

Transfer across Directlink

Chapter 7 contains the AER's considerations of the availability of power to flow south across Directlink. In summary, TransGrid and Powerlink stated that no power will be available in southern Queensland to flow south across Directlink during the summer of 2005–06 if a coincident peak occurs in the far north of NSW and southern Queensland. Further, given their geographic proximity, the two areas are likely to have coincident peaks. For the purposes of modelling likely interregional transfers, therefore, no peak power transfer should be assumed for the summer of 2005–06.

Regarding power transfers after the summer of 2005–06, the AER considered that:

- re-rating the Mudgeeraba–Terranora lines is likely to alleviate constraints on those lines to some extent and provide limited transfer capacity for Directlink to flow south under contingency conditions from 2006–07.
- From the summer of 2007–08, augmentations are likely to occur that will allow power to flow south across Directlink.

The ability of Directlink to flow power south for the summer of 2006–07 remains uncertain. Powerlink noted uncertainty about the impact of transformer capacity at Molendinar and constraints within Energex's network in the southern Gold Coast. While Powerlink recently confirmed its intention to bring forwards the installation of a second transformer at Molendinar for the summer of 2006–07, it is unclear whether it is possible to overcome limitations in Energex's network that would prevent both transformers being simultaneously energised. Given these uncertainties, it is reasonable for TransGrid to not rely on Directlink to provide network support to the far north coast of NSW for the summer of 2006–07.

Consequently, the AER considers that BRW's proposed south flow peak transfer limits during the summers of 2005–06 and 2006–07 are likely to be overstated.

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122 TEUS, *Response to the IES Final Report*, op. cit., pp. 10–11.

Nonetheless, it will adopt these transfer limits for the interregional modelling. The impact on the estimated interregional benefits for these years is unlikely to be material because there is no effect on the timing of market entry. Further, the modelling of interregional benefits is hourly across the entire year and includes hours outside of peak demand. From the summer of 2007–08, the transfer limits proposed by BRW appear to be reasonable.

Transfer across QNI

The AER notes that power available to transfer from NSW to Queensland across both QNI and Directlink is sourced from a common network that serves northern NSW from central NSW. This network may constrain the total north transfer. When this constraint applies, increased flow north across one interconnector must be offset by an equal reduction of power flow north across the other. In comparing Directlink or its alternative projects with the 'without Directlink' case, therefore, the total northward power transfer capability from NSW to Queensland is unchanged.

For northward power transfers on Directlink, the network constraints limit the maximum total transfer on QNI plus Directlink to 300 MW so any increase in transfer on Directlink requires a 1:1 reduction in QNI transfer. For southward power transfers on Directlink, any increase in transfer on Directlink adds to the QNI transfer capability. IES's reasoning that Directlink will not provide additional power flows north into Queensland is thus reasonable. Consequently, the AER expects that generation is unlikely to be deferred in Queensland. It does not accept that lower prices in NSW will be exported north across QNI and Directlink. When the northward constraint applies, Queensland prices will rise.

TEUS's original interregional modelling results (in PROSYM) did not incorporate the impact of transmission limits that exist between northern NSW and the rest of NSW, as proposed by BRW. In this regard, IES stated that TEUS's modelling results had not correctly modelled the transfer limits for northward flows across QNI and Directlink. Although TEUS stated that correctly modelling the transfer limits did not affect the re-estimation of interregional benefits in one case that was studied, the AER considers this has not been borne out in the additional modelling.

For the additional modelling undertaken by TEUS, the revised topology in PROSYM allows a transfer limit between northern NSW and NSW to be specified to address the issue raised by IES. In this regard, TEUS's additional modelling showed no new generation entry in Queensland that would be deferred by Directlink. The additional modelling provides a more reasonable basis for considering the appropriate transfer limits such that Directlink does not offer any increase in northward interconnection capacity to Queensland. The results from the additional modelling, therefore, can reasonably be used as estimates of the interregional benefits for this regulatory test assessment.

8.5.2 Interregional benefits modelling

DJV's application

TEUS identified four categories of interregional benefits attributed to Directlink (and its alternative projects):

1. reduced fuel and variable operating expenses and reductions in the frequency and level of voluntary load interruptions, given the displacement of more expensive generation in one region with less expensive generation in another region (energy benefits)

2. reduced capital and operating expenses from the deferred construction of new generators, given lower energy prices in regions of the NEM (deferred market entry generation benefits)

3. reduced expenses from the deferral of NEMMCO contracting with third parties to generate electricity to meet reliability standards, given a more efficient distribution of energy across the NEM (deferred reliability entry generation benefits)

4. reduced USE (after the introduction of NEMMCO contracting), given a more efficient distribution of energy across the NEM (residual reliability benefits).[123]

TEUS's original modelling estimated each of the categories of benefits in the 'with Directlink' case. Table 8.4 illustrates the magnitude of the interregional benefits for two scenarios.

Table 8.4 DJV's original estimate of interregional benefits with Directlink, by USE value ($ million, 1 July 2005)

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	(96.87)	201.72	(10.87)	13.90	107.89
$29 600/MWh	(96.87)	201.72	(10.87)	41.14	135.13

Submission and the consultancy report

TEUS's additional modelling used revised assumptions to address IES's concerns about assumed generator bidding strategies and transfer limits. Its additional modelling estimated each of the categories of benefits in the 'with Directlink' case. Table 8.5 illustrates the magnitude of the interregional benefits for two scenarios.

Table 8.5 DJV's revised estimate of interregional benefits with Directlink, by USE value ($ million, 1 July 2005)[(a)]

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	2.18	23.46	–	14.79	40.43
$29 600/MWh	2.18	23.46	–	43.77	69.41

(a) Only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

123 TEUS, *Estimation of Directlink's Alternative Projects' Interregional Market Benefits*, op. cit., pp. 6–8.

The results of IES's modelling estimated the value of interregional benefits in the 'with Directlink' case to be $76.6 million (based on a 9 per cent discount rate, medium growth, historical bidding and a USE value of $29 600 per MWh) and $46.2 million (based on a 9 per cent discount rate, medium growth, historical bidding and a USE value of $10 000 per MWh).[124] IES recognised differences remain between the values of the categories of interregional benefits generated using the different models. It considered the benefits to be as close as reasonably could be expected, however.

IES attributed the closeness of the results to the commonality of assumptions and method used, particularly having generators bid into the NEM in a similar manner. It believed that the results of the additional modelling can be relied on for the purposes of the regulatory test. TEUS stated that the results were as closely aligned as can be achieved and that it expected exact alignment of the results to be impossible.

The AER's considerations

The modelling of the interregional benefits is an inherently subjective process. The estimates generated by the modelling are highly sensitive to the model used and the assumptions adopted, and errors can occur. During the early stages of the additional modelling, for example, TEUS estimated the interregional benefits to be $214.7 million. It stated that:

> The most obvious conclusion is that total benefits have not changed greatly, even though benefits by category have changed, significantly in some cases. …. We further believe the newest analysis demonstrates the power of the feedback mechanisms that come into play when modelling competitive market entry to achieve a long run equilibrium—increases in one benefits category will usually be offset by decreases in another, making the overall results fairly robust with respect to initial assumptions.[125]

TEUS subsequently identified two corrections to its modelling that reduced the estimate of interregional benefits to the values detailed in table 8.5. Likewise, IES identified corrections to its initial modelling that increased its estimates of the interregional benefits to the values shown above.

TEUS's statement that 'feedback mechanisms' make the overall interregional benefit results insensitive to assumptions does not appear to be reasonable. The overall results are sensitive to the assumptions adopted. A comparison of the TEUS's original modelling results and the additional modelling results indicates the changes to the interregional benefits (tables 8.4 and 8.5). In these circumstances, the AER must exercise caution to ensure the outcomes of the regulatory test will not be determined by the use of inappropriate assumptions.

TEUS and IES adopted the same revised assumptions for their respective modelling and aligned the operation of their models as closely as possible. This modelling has been through several iterations and close consultation aimed at identifying errors and inconsistencies for correction. Given the consistency of assumptions and the close

[124] IES, *Directlink Conversion Application—Review of Market Modelling*, Melbourne, 17 October 2005, p. 18.

[125] TEUS, *Directlink's Alternative Projects' Interregional Market Benefits using Historical Bidding Strategies: Results of first case*, 14 June 2005, p. 15.

alignment of the estimated interregional benefits, the additional modelling undertaken by TEUS appears to be reasonable for use in this regulatory test assessment.

8.5.3 Conclusion

The AER will adopt the interregional benefits estimated by TEUS in the additional modelling. Table 8.6 illustrates the magnitude of the interregional benefits for two scenarios.

Table 8.6 The AER's conclusion on interregional benefits with Directlink, by USE value ($ million, 1 July 2005)[(a)]

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	2.18	23.46	–	14.79	40.43
$29 600/MWh	2.18	23.46	–	43.77	69.41

(a) Only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

8.6 The 'with alternative projects' case

Appendix F contains the AER's consideration of the interregional benefits provided by the alternative projects. In summary, table 8.7 shows that alternatives 1 and 2 provide the same interregional benefits as Directlink does. For alternative 3, table 8.8 illustrates the magnitude of the interregional benefits for two scenarios.

Table 8.7 The AER's conclusion on interregional benefits with alternatives 1 and 2, by USE value ($ million, 1 July 2005)[(a)]

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	2.18	23.46	–	14.79	40.43
$29 600/MWh	2.18	23.46	–	43.77	69.41

(a) Only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

Table 8.8 The AER's conclusion on interregional benefits with alternative 3, by USE value ($ million, 1 July 2005)[(a)]

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	–	–	–	(2.61)	(2.61)
$29 600/MWh	–	–	–	(7.73)	(7.73)

(a) Only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

9 The cost of Directlink and its alternative projects

9.1 Introduction

This chapter considers the costs of Directlink and its alternative projects. These costs are used in the regulatory test for estimating net market benefits (that is, gross market benefits less gross costs). If an alternative project maximises the net market benefits in most credible scenarios (that is, satisfies the regulatory test), the AER would use its cost to set the asset value for determining a revenue cap for DJV.

The remainder of this chapter sets out:

- DJV's application (section 9.2)
- submissions and the consultancy report (section 9.3)
- the AER's considerations (section 9.4)
- the conclusion (section 9.5).

9.2 DJV's application

BRW's report for DJV included estimates of the cost of the alternative projects it identified for the regulatory test. In its revised application (dated 22 September 2004), DJV described the costs estimated by BRW as comprising:

- the project capital cost
- interest during construction (IDC)
- lifecycle operating and maintenance costs (opex).[126]

DJV described the project costs as being:

> … designed to reflect the full cost to a network owner for the design, development, construction and operation of the asset.
>
> The base cost of each project can be divided into three asset cost categories: switchyard, transmission and easement costs. To estimate the full cost of an engineering, procurement and construction ('EPC') contract, BRW has added profit and overhead and the contractor's contingency. To the total contract cost, BRW added interest during construction ('IDC'), which has been calculated as the cost of financing each project to completion with consideration for the expected expenditure timetable for the project at the commercial discount rate.[127]

BRW engaged URS Australia Pty Ltd to help it identify a transmission line route that has a reasonable probability of receiving planning approval under the New South Wales planning arrangements. URS proposed a route contained within a 1 kilometre

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[126] DJV, *Application for Conversion*, 22 September 2004, op. cit., pp. 37, 43.
[127] ibid., p. 37.

wide corridor, approximately 47 kilometre long (of which 18 kilometres would be underground) between Terranora and Mullumbimby.[128] In regard to the proposed route, BRW stated that:

> An approved route would be longer than the nominated corridor, as a result of alignment changes within the corridor, as required to avoid specific localised environmental features identified by detailed on-site studies and could move outside the corridor for some locations. Additional route length is also required to allow for ground level changes not included in the plan view measurements. BRW considers that the combination of these factors could be expected to increase an actual transmission line route length by 15 % to 54 km, including 21 km of underground cable.[129]

Chapter 12 discusses BRW's estimates of the annual opex for Directlink and alternatives 1, 2 and 3. In summary, BRW provided an estimated opex of $2.92 million per year for Directlink and alternatives 1 and 2, and $2.73 million per year for alternative 3. Table 9.1 summarises BRW's estimate of the total capital cost of each of the alternative projects (based on 9 per cent discount rate).[130]

Table 9.1 DJV's estimated costs for Directlink and its alternative projects ($ million, 1 July 2005)

Capital cost components	Directlink[(a)]	Alternative 1	Alternative 2	Alternative 3
Development	na	3.1	4.2	4.2
Approvals	na	5.7	6.8	6.8
Easements and site acquisition	na	2.6	2.6	3.1
Project management	na	1.3	1.3	1.3
Equipment spares	na	4.0	2.3	0.9
Installed equipment	na	205.0	116.1	45.8
Project cost	172.2	244.0	146.6	68.3
IDC	na	13.1	10.2	6.6
Lifecycle opex[(b)]	31.4	31.4	31.4	29.3
Total capital cost	203.6	288.6	188.2	104.2

(a) BRW did not provide a breakdown of Directlink's project cost because the total cost of Directlink is based on its actual capital cost. IDC was capitalised into the project cost of Directlink.

(b) The lifecycle opex amount has been calculated as the present value of the annual opex required over the assumed life of the assets (40 years). See chapter 12 for more details on DJV's opex estimates.

na Not applicable.

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128 URS, *Alternative Projects to the Directlink Transmission Line—Environmental Review: Mullumbimby to Terranora (New South Wales)*, 9 March 2004, pp. 8-1, 9-1.

129 BRW, *Directlink: Selection and Assessment of Alternative Projects*, op. cit., p. 61.

130 id., *Selection and Assessment of Alternative Projects*, op. cit. pp. 1–9.

9.3 Submissions and the consultancy report

9.3.1 Directlink's capital cost

Parsons Brinckerhoff Associates (PB Associates) calculated a capital cost of $139.8 million for Directlink, using the midpoint of two estimates derived from costings (in the public domain) of high voltage direct current (HVDC) Light technology. DJV responded that PB Associates' estimate of the capital cost of Directlink is inaccurate and that the actual capital cost of Directlink should be adopted. It raised concerns about the scope and accuracy of the data on which PB Associates had relied. Further, it stated that firm costing data for new HVDC Light technology is available only from ABB Power Systems (ABB). DJV also noted that it had commercial incentives to minimise the cost of Directlink.

9.3.2 Undergrounding of lines for alternatives 2 and 3

For each of the alternative projects, PB Associates estimated the costs with undergrounding of lines (both full and partial) as proposed by BRW and full overhead construction of lines.[131] It stated that it is appropriate to assume, without legal directives for undergrounding, least cost construction using full overhead construction.

DJV stated that PB Associates had provided no detail and made no assessment of environmental issues associated with the alternative projects, and that any statement by PB Associates on legal directives should not be relied on.[132] It stated that its application includes an assessment by URS of the extent to which appropriate route selection and undergrounding would be necessary to achieve environmental approval. Further, it noted that the NSW Department of Infrastructure Planning and Natural Resources (DIPNR) had indicated a route selection and extent of undergrounding not materially different to those of URS.

Following PB Associates' report, the ACCC sought advice from DIPNR on:

- whether there are any legal obligations to underground transmission lines in the northern NSW region
- the assessment process that DIPNR would undertake in relation to the location of electricity transmission lines.[133]

DIPNR responded that:

> … PB Associates' conclusion about 'absence of legal directives for undergrounding' appears to be overly simplistic with respect to the reality of constructing and operating a transmission line in NSW. The Department considers that a more relevant legal question is whether or not a project could obtain a planning approval.

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131 PB Associates, *Review of Directlink Conversion Application*, op. cit., pp. 43–5, 49–50, 57–8.
132 DJV, *Submission in Response to PB Associates Report*, op. cit., pp. 32–3.
133 ACCC, Letter to DIPNR: Environmental approvals for electricity transmission lines, Canberra, 1 December 2004.

> There is a legal requirement for the construction and operation of transmission lines to obtain planning approval in accordance with the requirements of the NSW *Environmental Planning and Assessment Act 1979* (EP&A Act). Transmission lines are in almost all cases assessed under Part 5 of the EP&A Act.
>
> To comply with the EP&A Act, any determining authority (generally any public authority whose approval is required) must take into account to the fullest extent possible all matters affecting or likely to affect the environment. If the carrying out, or granting of an approval in relation to an activity, is likely to significantly affect the environment, then an Environment Impact Statement (EIS) must be prepared. In the case of Directlink, the Department considers that it would be extremely unlikely that an above ground alternative would not require an EIS.
>
> When an EIS is prepared, the Proponent must obtain an approval from the Minister for Infrastructure and Planning. The Minister is legally required to consider the environment impact of the activity including an independent environment impact assessment report prepared by the Director General of the Department.[134]

DIPNR engaged Connell Wagner to identify a cost-effective and environmentally acceptable route that would have the same functionality as the existing Directlink line.[135] It indicated that its preferred option would be a fully underground route but accepted that it could recommend approval for an alternative route that includes a combination of overhead and underground lines.

9.3.3 Undergrounding of alternative 1

In its report, BRW stated that alternative 1, which uses HVDC Light technology, must be fully undergrounded because the HV transistor equipment at the converter stations is susceptible to lightning. PB Associates indicated that this is incorrect and not supported by documentation in the public domain:

> BRW responded to questions by PB Associates regarding this claim. The response states that insulated gate bipolar transistors (IGBT) are more susceptible to lightning overvoltages than more conventional thyristor technology. This is not disputed by PB Associates, but PB Associates contends that there exists industry accepted practises, common in the transmission and distribution industry, that can be used to prevent such overvoltages reaching the IGBTs as well as the possible provision of fast acting protection solutions. [136]

PB Associates also cited a 3 megawatt 10 kilovolt experimental project in Hellsjon Sweden for which a 10 kilometre length of overhead line has been used. Consequently, it removed the cost for undergrounding from alternative 1.

BRW stated that the PB Associates’ reasons for not requiring underground cabling are theoretical and that it has obtained advice from ABB stating that it will not ‘sell or support a HVDC Light facility using overhead cable’. BRW indicated that the Hellsjon project was developed to prove the converter technology and used an existing overhead line with special switching devices to protect the converters. The small scale pilot installation, however, was customised to use existing infrastructure and cannot be extrapolated to large scale commercial applications, particularly when

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[134] DIPNR, *Alternatives to the Directlink Transmission Line*, Sydney, 7 December 2004.

[135] Connell Wagner, *Directlink Best Alternate Route Environmental Assessment*, Sydney, 29 September 2004.

[136] PB Associates, *Review of Directlink Conversion Application*, op. cit., p. 41.

ABB stated that the systems are designed for use with cables and not suited to overhead lines.[137]

9.3.4 Relative cost of HVDC Light technology

Alternative 2 is a link using HVDC conventional technology. Directlink and alternative 1 are also HVDC links, but use the Light technology developed and marketed by ABB. BRW's estimates showed the capital cost of alternative 1 to be higher than that of alternative 2, even if the cost of undergrounding is removed.

PB Associates noted that it would expect the cost of HVDC conventional technology used in alternative 2 to be greater than that of the HVDC Light technology used in Directlink and alternative 1. It indicated that ABB developed and marketed HVDC Light technology on the basis that it is more economical than HVDC conventional technology at lower power transfer levels and over shorter distances, such as those used by Directlink. DJV responded to PB Associates' report by stating:

> …[BRW's] costing of Alternatives 1 and 2 are based on actual manufacturers' quotations. It appears that while ABB, the manufacturer and provider of HVDC Light, was initially very commercially aggressive, the HVDC market has changed in recent times and HVDC Light is no longer less expensive.[138]

9.3.5 Cost for providing post-contingent support

DJV has claimed deferral of Port Macquarie augmentations with the use of a coordinated voltage control scheme. It stated that it is committed to working with TransGrid to design and implement a control scheme to enable Directlink, and alternatives 1 and 2, to provide post-contingent network support. It estimated the cost of this control scheme to be $2.6 million and stated that this is a small cost to pay for such a capability.

9.4 The AER's considerations

9.4.1 Directlink's capital cost

The AER has considered DJV's proposed capital cost for Directlink and PB Associates' view. It has decided to adopt the capital cost provided by DJV because it is based on quotations from the only supplier of the HVDC Light technology, ABB, and thus is likely to be more accurate than an average of estimates from the public domain. The estimates in the public domain may be outdated or for projects that differ in specification from Directlink.

9.4.2 Undergrounding of lines for alternatives 2 and 3

Although the URS report proposed 18 kilometres of undergrounding along its recommended 'best route', BRW stated that additional route length is also required to allow for ground level changes, so it proposed 21 kilometres of underground cable. It

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137 DJV, *Submission in Response to PB Associates Report*, op. cit., p. 31; BRW, *Directlink: BRW Comments on PB Associates Report of 26 November 2004*, Port Macquarie, 2004, pp. 7–8.

138 DJV, *Submission in Response to PB Associates Report*, op. cit., p. 33.

claimed that the following cable types, lengths and costs for alternatives 2 and 3 are required (table 9.2).

Table 9.2 BRW's estimated cable and line requirements for alternatives 2 and 3 (1 July 2005)

Alternative 2			Alternative 3		
Types	**Length**	**Cost**	**Types**	**Length**	**Cost**
HVDC overhead pole line ($0.2 m / km)	33 km	$5.1 m	132 kV AC single circuit overhead pole line ($0.2 m / km)	33 km	$5.1 m
HVDC conventional underground cable ($1.2 m / km)	17 km	$20.3 m	132 kV AC underground cable ($1.1 m / km)	21 km	$24.0 m
110 kV AC underground cable ($1.1 m / km)	4 km	$4.6 m			
Total	54 km	$30.0 m	Total	54 km	$29.1 m

(a) The costs may not total exactly, as a result of rounding.

AC = alternating current.

Note 3 to the 1999 regulatory test states:

> The costs identified in determining the market benefit should include 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. 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. Any other costs should be disregarded.[139]

The rationale for this approach is set out on pages 13–14 of the background paper to the regulatory test. In summary, the ACCC considered that the investment analysis should include all costs of meeting existing environmental requirements of the jurisdictional governments and their environmental agencies. This way, issues of public policy on the environment are determined by the relevant jurisdictions and their expert agencies, and not as part of an electricity network investment assessment process.

The AER considers that a similar approach should be taken for assessing DJV's conversion application. That is, unless justified by reference to other code provisions, the inclusion of undergrounding costs should generally be determined by whether a legislative or regulatory requirement would prevent the construction of the line above ground.

In a letter dated 7 December 2004, DIPNR advised that the construction and operation of transmission lines would require planning approval in accordance with the NSW *Environmental Planning and Assessment Act 1979*. The letter further stated that:

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139 ACCC, *Regulatory Test for New Interconnectors and Network Augmentations*, Canberra, 15 December 1999, p. 23.

> The Department has undertaken a comprehensive and independent review that identifies an environmentally acceptable route as an 'alternative' to Directlink. The Report, which is attached, concludes that, whilst the Department's preferred option would be for a fully underground route, it accepts that it is possible that it could recommend approval for an alternative which includes a combination of overhead and undergrounding. However, given the particular sensitivities of the study area, and the strengthening community attitudes opposing above ground lines, the extent of undergrounding identified in the Report would be insisted as an absolute minimum requirement. Following further, more detailed assessment as part of the post approval activities, it is likely that additional mitigation measures, including additional undergrounding, could be required.[140]

The DIPNR report dated November 2004 refers to a study that the department commissioned from Connell Wagner to identify a cost-effective and environmentally acceptable route that would have the same functionality as the existing Directlink line. The study (dated 29 September 2004) identified two options that would likely achieve planning approval, one of which (option 1) involves overhead transmission with 17 kilometres of undergrounding. The AER notes that URS's 'best route' and Connell Wagner's 'option 1' are not materially different, and both adopt the foothills corridor. Their recommendations for partial undergrounding are also closely aligned.

The DIPNR report concluded:

> The Department's preferred option would be for a fully underground route (ie Connell Wagner Option 2 following the Motorway). Notwithstanding, the Department accepts that it is possible that it would consider an option with a combination of overhead and undergrounding (ie Connell Wagner Option 1). However, given the sensitivities of the local area, the extent of undergrounding identified in the Connell Wagner report would be insisted as an absolute minimum requirement in order to recommend that the project be approved.[141]

PB Associates estimated the costs of alternatives 2 and 3 with undergrounding (full and partial) as proposed by BRW and with full overhead construction of transmission lines. It stated that it had:

> …provided the costs of a fully overhead line construction due to the fact that, in the absence of legal directives for undergrounding it is appropriate to assume least cost alternatives which in this case represent the overhead construction type. [142]

Its report did not note whether planning approval could be obtained without undergrounding.

As discussed, the 1999 regulatory test essentially limits undergrounding costs to the costs of complying with legal and regulatory requirements. But in the case of a conversion application where the transmission line has already been constructed, it is not possible to go through the planning consultation process and obtain a binding decision from the relevant authority on the minimum undergrounding necessary for approval to be granted. In this regard, the application of the regulatory test in a conversion application can be differentiated from its usual application. In a conversion application, a hypothetical situation is being considered where an asset has already been constructed and it is not possible to seek a binding ruling on the

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140 DIPNR, *Alternatives to the Directlink Transmission Line*, op. cit.

141 id., *Environmental Planning Report—Alternatives to Directlink Transmission Line (Mullumbimby to Terranora)*, Sydney, November 2004, p. 8.

142 PB Associates, *Review of Directlink Conversion Application*, op. cit., pp. 43, 50.

requirement for undergrounding. An actual environmental impact statement is not prepared and the relevant planning authority or environmental agency can provide only its best advice or guidance based on a desktop review of environmental issues. By contrast, in the usual application of the regulatory test, network service providers (NSPs) are considering a project that may be constructed and, therefore, can seek a binding ruling on the requirement for undergrounding.

Further, the AER is aware of cost-effective alternatives to undergrounding that NSPs have previously adopted to address environmental and social impacts, in response to community consultation processes. A proponent would be expected to consider these alternatives as part of any regulatory test assessment:

- screen planting to reduce visual impact of towers/poles;
- use of taller structures and over-canopy construction to reduce or eliminate vegetation clearing
- vegetation feathering
- painting to reduce visual impact.

The AER has considered the reports prepared by DIPNR and its consultant Connell Wagner, as well as the reports from PB Associates, BRW and URS. It considers that the DIPNR report provides the best available evidence on the minimum undergrounding required for a project comparable to Directlink to be likely to comply with the necessary legal and regulatory requirements.

BRW claimed 21 kilometres of underground cable due to additional route length to allow for ground level changes. However, the Connell Wagner report noted that the underground section of the route avoids the steepest terrain and densely vegetated land, and keeps largely to open country.[143] Based on DIPNR's report, therefore, the cost for 17 kilometres of undergrounding for alternatives 2 and 3 has been allowed. In accordance with BRW's estimates of the capital components, the AER has removed the undergrounding cost of around $4 million each (for 4 kilometres) from alternatives 2 and 3.[144]

This case differs from certain alternatives considered in the Murraylink decision in that the relevant planning authority (DIPNR) in this case commissioned an expert report, conducted its own review and concluded what would be necessary to obtain planning approval.

9.4.3 Undergrounding of Directlink and alternative 1

PB Associates questioned the need to underground the cables (rather than use overhead lines) for HVDC Light technology because the equipment at the converter

143 Connell Wagner, op. cit., p. 30.

144 BRW, *Selection and Assessment of Alternative Projects*, op. cit., p. 14. For alternative 2, the cost difference between HVDC underground cable and HVDC overhead pole line is $1.0 million per kilometre. For alternative 3, the cost difference between 132 kV AC underground cable and 132 kV AC overhead pole line is $0.9 million per kilometre.

stations is susceptible to lightning strikes. It indicated that industry accepted practices can address concerns about lightning strikes on the equipment. DJV obtained advice from ABB, however, that it will not sell or support a HVDC Light system using overhead cable. ABB developed the HVDC Light technology and has the best understanding of the technology. The AER thus considers it is reasonable to include the cost of full undergrounding of the cables for Directlink and alternative 1.

9.4.4 Relative cost of HVDC Light technology

DJV has not substantiated its assertions that ABB was initially aggressive in selling HVDC Light technology and that market conditions have since changed. There appear to be several reasons, however, that HVDC Light may be more expensive than HVDC conventional technology—for example, the lower scale of production, the relatively new nature of the technology and the greater competition in the conventional HVDC market. As the producer of HVDC Light technology, ABB is in the best position to advise on the costs of its technology. The AER will thus adopt the costs proposed by BRW, which are based on the advice of ABB.

9.4.5 Cost for providing post-contingent support

As discussed in section 7.4.1, DJV stated that Directlink can defer the Port Macquarie augmentations with a coordinated voltage control scheme. However, the AER has not allowed deferral benefits for the Port Macquarie augmentations because there is insufficient information to support DJV's proposition that Directlink can defer the augmentations. Further, the AER notes that DJV has not provided any additional information to justify the requirement of a post-contingent control scheme to support other areas of the NSW network. Consequently, the cost of $2.6 million for the control scheme is removed from the cost of Directlink and alternatives 1 and 2.

9.5 Conclusion

In light of the above considerations, the AER considers the capital cost of Directlink and the alternative projects to be as shown in table 9.3 (based on a 9 per cent discount rate).

Table 9.3 The AER's conclusion on costs of Directlink and its alternative projects ($ million, 1 July 2005)

Capital cost components	Directlink	Alternative 1	Alternative 2	Alternative 3
Project cost	169.3	241.1	139.2	63.9
IDC	na	13.1	10.2	6.6
Lifecycle opex[(a)]	20.6	20.6	20.6	18.4
Total capital cost	189.9	274.8	170.0	88.9

(a) The opex amount has been calculated as the present value of the annual opex required over the assumed life of the assets (40 years). See chapter 12 for more details on the allowed opex.
na Not available.

As discussed in section 7.3.4, the IDC and contingencies are legitimate costs of an engineering, procurement and construction (EPC) contract. The AER considers that a contingency of 10 per cent is consistent with generally accepted practice in the industry.

Chapter 12 discussed the opex allowance. In summary, the AER considers a reasonable opex allowance for Directlink and alternatives 1 and 2 is $1.92 million per year. The lifecycle cost of this opex is $20.60 million. Likewise, a reasonable opex allowance for alternative 3 is $1.72 million per year, and the lifecycle cost of this opex is $18.45 million.

10 Market development scenarios and sensitivity analysis

10.1 Introduction

The regulatory test requires that alternative market development scenarios be considered. A project satisfies the test if it maximises the net market benefit in most (although not all) credible scenarios. In addition to market development scenarios, the regulatory test specifies that sensitivity analysis should be undertaken. The role of market development scenarios is to capture any uncertainty about the future state of the electricity market and to ensure the project that satisfies the regulatory test is robust to different assumptions about the future development of the market. The role of sensitivity analysis is to test the variability of the gross market benefits to key assumptions.

This chapter sets out:

- the DJV's application (section 10.2)
- submissions and consultancy reports (section 10.3)
- the AER's considerations (section 10.4)
- the conclusion (section 10.5).

10.2 DJV's application

DJV studied 26 market development scenarios but considered only six scenarios to be credible. It regarded the remaining scenarios as sensitivity tests. DJV proposed that the credible scenarios include:

- low, medium and high demand forecasts
- long run marginal cost (LRMC) and short run marginal cost (SRMC) generator bidding strategies
- a 9 per cent discount rate
- a value of unserved energy (USE) of $29,600 per MWh
- alternative project costs that are 10 per cent higher and 10 per cent lower than the base estimate of the project cost.

For the sensitivity testing, the net market benefits of the alternative projects were also determined with:

- 7 per cent and 11 per cent discount rates
- a USE value of $10 000 per MWh.

10.2.1 Demand growth rates

BRW developed low and high growth rate scenarios using low and high growth forecasts from the TransGrid and Powerlink 2004 annual planning reports. Changing forecast load growth alters the timing of when network contingencies cause constraints to emerge and, therefore, the timing of augmentations required to address those constraints. Table G.1 (appendix G) summarises the timing of the augmentations proposed by BRW for the alternative projects, for different growth rates.

Different growth rates also have an effect on the timing of the deferral period and thus on the level of network deferral benefits. Table G.2 summarises BRW's estimates of the network deferral benefits for different growth rates.

Further, changing the forecast load growth rate alters the value of the interregional benefits. Higher load growth increases demand for electricity in the National Electricity Market (NEM) and affects the resulting price of electricity generation. This will have an effect on the way in which generators are dispatched to meet demand and the timing of new generation entry in response to the different prices. Table G.3 summarises TransÉnergie US Limited's (TEUS) estimates of the interregional benefits using historical bidding strategy, for different growth rates.

10.2.2 Generator bidding

As an alternative to its proxy LRMC bidding behaviour used in the interregional modelling, TEUS assumed that generators bid into the NEM at their SRMC (a price that is lower than TEUS's LRMC). A change in the way in which generators bid will affect the resulting prices of electricity generation in the NEM: a reduction in bid prices is expected to reduce observed prices. This will affect the interregional benefits by changing the profitability of new entry: price rises will likely take longer to make new entry profitable and thus new entry will be deferred. This too will affect the interregional benefits by changing the mix of generators dispatched to meet demand, and thus change the energy savings.

TEUS's estimates of the interregional benefits based on the:

- SRMC bidding are summarised in table G.4
- LRMC bidding are summarised in table G.5.

10.2.3 Discount rates

DJV used a commercial discount rate of 9 per cent for the credible scenario. It applied a range of ±2 percentage points around the base estimate of the discount rate (9 per cent) for the sensitivity analysis. Changing the discount rate affects the present value of each component of the net market benefits calculation: capital costs, network deferral benefits and interregional transfer benefits.

Capital cost

The capital cost of Directlink and its alternative projects include interest during construction (IDC) and the present value of the lifecycle operating and maintenance expenditure (opex) of the asset. Both the IDC and opex vary with the discount rate used. Table G.6 summarises BRW's estimated present value of the costs of each alternative project for the various discount rates.

The costs of the various network augmentations discussed in chapter 7 also include IDC and the present value of lifecycle operating expenses, which will vary with the discount rate used. Table G.7 summarises BRW's proposed present value of the costs of these augmentations for the various discount rates.

Network deferral benefits

A change in the discount rate affects the difference between the present value of the augmentations under the reference case ('without Directlink') and the 'with Directlink' case. Table G.2 summarises BRW's estimated network deferral benefits for the various discount rates.

Interregional transfer benefits

A change in the discount rate will also affect the estimates of interregional benefits. Tables G.3–G.5 summarise TEUS's estimated interregional benefits for the various discount rates.

10.2.4 Value of unserved energy

As an alternative to the approximation of the USE value developed by VENCorp ($29 600 per MWh), TEUS used the wholesale price cap in the NEM or the value of lost load (VOLL) ($10 000 per MWh).[145] The assumed USE value used in the modelling will change the estimated cost of the residual reliability component of the interregional benefits. Tables G.3–G.5 summarise TEUS's estimated interregional benefits for both USE values.

10.3 Submissions and consultancy reports

10.3.1 Demand growth rates

Parsons Brinckerhoff Associates (PB Associates) reviewed the growth rates proposed by BRW and considered them to be reasonable. It noted that actual growth rates for both Queensland and the far north coast of New South Wales have been higher than forecast. Both Powerlink and TransGrid stated that recent load growth for the southern Gold Coast and far north coast of NSW have exceeded forecasts. TransGrid stated that maximum demand during the summer of 2004–05 exceeded the forecast for the summer of 2006–07. BRW took this into account when developing its forecasts.

10.3.2 Generator bidding

Intelligent Energy Systems (IES) noted that the regulatory test requires sensitivity analysis using SRMC bidding. Further, it stated that the test also requires a least cost

145 Clause 3.9.4 of the National Electricity Code caps the price of electricity in each region of the NEM to the VOLL. The Reliability Panel reviews the VOLL each year.

planning scenario. IES noted a close connection between a least cost planning scenario and a SRMC bidding scenario, but the two are not necessarily the same. With a SRMC bidding scenario, the resulting high levels of reliability generation entry may not be the lowest cost development relative to that which would result under the least cost planning scenario.

TEUS noted that the ACCC did not require the use of a least cost planning scenario in its Murraylink decision. It stated, however, that the SRMC bidding scenario and modelling assumptions that TEUS adopted would generate results that are representative or comparable to a least cost planning scenario.

10.3.3 Discount rates

IES stated that the 9 per cent discount rate used by TEUS seems reasonable and the range of discount rates used was consistent with its expectation. TXU stated that the discount rates adopted by DJV are not high enough to reflect a commercial discount rate commensurate with the merchant risk in the NEM. It indicated that a post-tax real weighted average cost of capital (WACC) of around 14 per cent better reflected the risk of merchant generation.

10.3.4 Value of unserved energy

IES considered the range of USE values ($10 000 per MWh and $29 600 per MWh) contained in the modelling of interregional benefits is sufficient for the sensitivity analysis in the regulatory test.[146] IES noted that the USE estimate derived by VENCorp is based on a study in Victoria and may not reflect the reliability impacts of Directlink. It also noted, however, the Murraylink decision used both the market price cap of VOLL ($10 000 per MWh) and VENCorp's estimated value of customer reliability of $29 600 per MWh. To IES's knowledge, no detailed studies of the value of USE to customers in other NEM regions exist. It believed that both the market price cap and VENCorp's estimate need to be considered for the purposes of the regulatory test and it would be reasonable to give equal weighting to the two values of USE.[147]

TXU argued that the the value of USE should only apply the VOLL figure of $10 000 per MWh, as required by the regulatory test.

10.3.5 New market entry costs

IES noted that new market entry costs are a critical assumption. For new market entry to occur, the premium of the market price (that is, the margin of market price above the SRMC) for electricity generation must exceed the SRMC of generation by a sufficient margin to cover the long run capital and operating costs (new market entry costs) of a new generator. IES thus noted that:

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146 IES, *Directlink Conversion Application: Review of Interregional Market Benefits*, Melbourne, 26 April 2005, p. 28.

147 IES, *Directlink Conversion Application—Review of Market Modelling*, Melbourne, 17 October 2005, p. 34.

> Many views are expressed in the market over the fixed costs of new entry generators, and the ACIL reported figures should be seen as such. Sensitivity analysis should be used to address uncertainty associated with the development of these numbers.[148]

TEUS responded that the new market entry costs used in its modelling are based on publicly available information and that they are well supported and reasonable. Its additional modelling results included sensitivities for high and low market entry cost assumptions.

10.4 The AER's considerations

10.4.1 Demand growth rates

The regulatory test requires the use of reasonable alternative market development scenarios incorporating varying levels of demand growth at relevant load centres. Both the deferral benefits and interregional benefits are sensitive to the assumed level of demand growth. BRW's load growth forecasts have been accepted by PB Associates and are consistent with those proposed by the relevant transmission network service providers in planning reviews. The AER considers the forecasts to be reasonable for this regulatory test assessment.

While TransGrid indicated that recent actual demand in the north coast of NSW has exceeded the load forecast, the load forecasts provided by BRW are consistent with the latest published forecasts available in the market and used by TNSPs in their annual planning reviews. Each of the demand growth rates identified by BRW, therefore, may reasonably occur and are credible. Incorporating each of the low, medium and high growth rates as credible scenarios allows the regulatory test to incorporate the spectrum of likely growth. The AER has thus decided to adopt the load forecasts provided by BRW.

BRW has not, however, appropriately interpreted the implication of higher growth rates for network augmentations under the reference case. It assumed in the high growth case that potential reliability failures will arise earlier and augmentations to address these potential reliability failures will likewise occur earlier. In particular, BRW indicated that the Dumaresq–Lismore 330 kV line (and correspondingly the Tenterfield back-up supply) under the high growth case would be built one year earlier (2006–07) than under the medium growth case. While this may be theoretically consistent with the load modelling developed by BRW, the required lead time means that these augmentations would not be completed in time to address the potential reliability failures. TransGrid stated that construction of the Dumaresq line would take four to five years and that it would be unable to complete construction of that line before the summer of 2007–08.

Prior to the summer of 2002–03, TransGrid did not envisage the level of demand in northern NSW. During 2002–03, it had reason to suspect that demand would exceed that forecast, which was confirmed by the level of demand during the summer of 2003–04. The earliest time at which TransGrid could be sufficiently certain of a

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[148] IES, *Directlink Conversion Application: Review of Interregional Market Benefits*, Melbourne, 26 April 2005, p. 45.

supply deficit to justify committing to the construction of the Dumaresq line was during the summer of 2003–04. Allowing for planning, approval processes and construction lead time, the earliest practical time that the Dumaresq line would be completed under the high growth case is the summer of 2007–08. Consequently, TransGrid is reliant on a combination of potential load shedding and the uprating of line 966 to manage any reliability failures before that summer.

Table G.8 summarises the AER's view of the timing of network deferrals under the reference case for the various growth rates, recognising the practical limitation on completing construction of the Dumaresq line before the summer of 2007–08. Based on its views of the timing of the augmentations required to address network reliability standards, the AER considers the values of the network deferral benefits attributed to Directlink (or one of its alternative projects), for various growth rates, are as shown in table G.10.

10.4.2 Generator bidding

The regulatory test prescribes the use of market development scenarios that base market generation entry on forecasts of spot price trends that reflect a range of market outcomes: from SRMC bidding behaviour to simulations that approximate actual market bidding and prices. In chapter 8, the AER considered historical bidding is more likely than LRMC bidding to approximate actual market bidding behaviour. Historical bidding also generates price outcomes that are more consistent with prices expected to occur in the market. It will thus be considered as a credible scenario.

An assumption that generators bid into the NEM at the LRMC is not consistent with actual market bidding behaviour and does not generate prices that approximate actual market price outcomes. In a competitive market, generators would not bid at the LRMC, given the competitive threat of others entering the market and bidding at a price lower than the LRMC. Nonetheless, the sensitivity analysis can use LRMC bidding to test the variability of the gross market benefits.

The SRMC is the lower bound of what generators could bid into the market and cover the marginal costs of their generation. But it does not reflect observed market bidding behaviour, and the resulting price patterns do not reflect what would be expected. SRMC bidding results in low prices that are not sustainable and could necessitate generators exiting the market. It is therefore not considered a credible scenario, but it will be used in the sensitivity analysis.

10.4.3 Discount rates

Where systematic risk, the risk that is applicable to the overall market, affects forecast cash flows then consideration must be given to the appropriate way of incorporating that risk into the discount rate. The capital asset pricing model (CAPM) framework provides for risks associated with revenues and the risks associated with costs to be separately identified and different discount rates to be applied. In the case of forecast revenue cash flows, the appropriate discount rate to use is one that is higher than the risk-free rate. The rate used to discount cost cash flows will be either equal to the risk-free rate or less than the risk-free rate where there is systematic risk. For example, in the cost based depreciated optimised replacement cost model for the Moomba to Sydney Pipeline, NERA and Professor Grundy advised that the appropriate rate for discounting future pipeline costs would be to use the risk-free rate.

In the case of a regulatory test assessment, there is significant complexity in separately identifying and discounting the cash flows according to their associated risks. The application of the regulatory test typically involves analysis of a number of different cash flows, such as, energy benefits, capital costs and operating costs which may attract different discount rates. In the case of Directlink, the majority of the cash flows relate to deferral of capital costs and this suggests that the appropriate discount rate should be higher than risk-free because the capital costs are normally funded by debt/equity. On balance, the AER considers that the use of a single discount rate which reflects the risk faced by a private enterprise investment in the electricity sector is likely to be a reasonable proxy.

The regulatory test identifies the discount rate as a key variable for sensitivity analysis. Each component of the net benefits analysis is sensitive to this assumption. Consequently, it is appropriate to test the sensitivity of the regulatory test results to this assumption.

The AER considers that the discount rates proposed by DJV are reasonable. In particular, the use of a 9 per cent discount rate is consistent with the estimate adopted by the ACCC in its Murraylink decision and falls within the range of discount rates applied in the following applications of the regulatory test:

- NEMMCO's South Australia – New South Wales Interconnector (SNI) analysis
- VENCorp's Latrobe–Melbourne study
- Powerlink's applications for a new network asset in the Darling Downs area and Gold Coast/Tweed area.

IES also noted that a discount rate of 9 per cent is reasonable. While TXU suggested a higher discount rate of 14 per cent, it has not provided analysis to support this alternative discount rate. The AER considers that the changes in the discount rate do not affect the ranking of Directlink or its alternative projects, and thus the outcome of the regulatory test. The sensitivity analysis of ±2 per cent around the 9 per cent base discount rate, however, will sufficiently indicate the reasonableness of DJV's proposal and the proposal's sensitivity to key variables.

Based on the various discount rates used, and for the purposes of applying the regulatory test, appendix G summarises the AER's draft decision on the following values:

- the costs of the augmentations in the reference case (table G.9)
- network deferral benefits (table G.10)
- interregional benefits (table G.11)
- the costs of each alternative projects (table G.13).

10.4.4 Value of unserved energy

There is uncertainty about the appropriate value of USE for a regulatory test assessment. The USE value is likely to vary according to factors such as the opportunity cost of the type of customer subject to the lost load, and the time of day at which the demand is unserved. Given this uncertainty, it is appropriate to test the sensitivity of the results to this assumption.

TEUS advised that the VENCorp estimate of $29 600 per MWh for the USE value is credible. IES noted that the range of prices used ($10 000 per MWh and $29 600 per MWh) is sufficient for sensitivity analysis. It also indicated that both values need to be considered and given equal weighting for the regulatory test.

The AER notes that VENCorp’s assessment of the USE value required a number of assumptions, including:

- a survey of Victorian customers in various sectors to estimate values applicable to interruptions of different durations
- the weighting of results according to the customer populations of these sectors in Victoria
- the further weighting of the results according to the distribution of the duration of end use customer outage statistics for network initiated outages in Victoria.

In its Murraylink decision, the ACCC considered that the current wording of the regulatory test does not specify VOLL to be applied for the estimation of market benefits. The AER concurs with this and acknowledges that VOLL, being the wholesale market price cap of $10 000 per MWh, does not necessarily reflect the real or true value of USE, which varies with customer type and location and the sequence in which TNSPs shed load. DJV, however, has not substantiated that the estimate of $29 600 per MWh better reflects the USE value to customers outside of the Victorian region considered in VENCorp’s analysis. Without further analysis of the opportunity cost of USE to customers outside of that region, it is not possible to state whether VENCorp’s estimate is more or less suitable as a general measure of USE. Without an accurate value for USE, therefore, VOLL should also be used. IES also advised the AER that both values need to be considered and given equal weighting.

Given the uncertainty about the value of USE, the AER considers that both values ($10 000 per MWh and $29600 per MWh) should be used for this regulatory test assessment, with equal weighting in the credible scenarios and for the sensitivity analysis. It has adopted the estimates of the interregional benefits for both values of USE, which are summarised in table G.11.

10.4.5 New market entry costs

TEUS’s estimate of new market entry costs is derived from a publicly available report by ACIL Tasman, which appears to be a reasonable source. There are varied opinions about market entry costs, however, so testing the sensitivity of the interregional benefits modelling results is appropriate. TEUS’s additional modelling results include cases for new entry costs that are ±10 per cent on the reported market entry costs. IES reviewed the results for these cases and considered that the total benefits are in the expected range. The AER considers the modelling to be reasonable for this regulatory test assessment and has adopted the results of the interregional benefits for sensitivity testing as shown in table G.11.

10.4.6 Alternative project costs

The AER considers that the costs of each alternative projects are unlikely to vary significantly. Further, the cost of the alternative projects (and reference case augmentations) includes an allowance for contingencies to reflect the likely upper cost of an engineering, procurement and construction (EPC) contractor. This allowance provides for the possibility that the actual costs of construction may exceed those envisaged under the EPC contract. In this case, it would not be credible to include another contingency on top of the contingency already provided.

Depending on the specific contractual terms, an EPC contractor would likely bear the burden of costs additional to an allowed contingency. Variation in the cost of the alternative projects or relevant network augmentation options will not be included as a credible scenario but will be undertaken as a sensitivity analysis. Table G.13 sets out the results of this sensitivity analysis of the costs of the alternative projects.

10.4.7 Alternative commissioning dates

The Broadwater co-generator or Metgasco's proposed embedded generator might provide network support to the far north coast of NSW and defer the construction of the Dumaresq–Lismore 330 kV line. To test the sensitivity of the network deferral benefits to this possibility, sensitivity analysis is undertaken for the deferred timing of the need for the Dumaresq line to the summer of 2010–11 (consistent with PB Associates' advice). Table G.10 summarises the impact of this revised timing on the network deferral benefit.

10.4.8 Results of market development scenarios and sensitivity analysis

The AER's regulatory test assessment included 40 market development scenarios of which six scenarios were considered to be credible. The remaining scenarios were used as sensitivity analysis.

Based on the different values used for the discount rate, demand growth, USE, project cost, market entry cost and timing of the embedded generation option, appendix G sets out the following estimated results:

- network deferral benefits (table G.10)
- interregional benefits (table G.11)
- gross market benefits (table G.12)
- total costs of Directlink and its alternative projects (table G.13)
- net market benefits (table G.14).

The network deferral benefits of Directlink and its alternative projects vary with the discount rate and demand growth. The impact due to different growth rates tends to dominate the effect of a change in discount rate—for example, higher demand growth means shorter deferral period and thus lower deferral benefits. The sensitivity analysis of an embedded generator providing network support also shows that the deferral benefits of the alternative projects would be lower because the deferral period is shorter. The AER notes that the median network deferral benefits for the credible scenarios are the same as the median for the sensitivity scenarios.[149]

The interregional benefits of the alternative projects vary with more factors, including the discount rate, demand growth, value of USE and generator bidding strategy. The results also span a wider range and appear to be sensitive to demand growth. With higher demand growth, the mix and size of generation entry change such that the energy benefits are affected in terms of dispatch cost savings. The median interregional benefits for the credible scenarios are lower than the median for the sensitivity scenarios but the difference is not substantial.

Alternative 3 does not provide any increase in the interconnection capacity between Queensland and NSW. Its interregional benefits, therefore, were not expected to be material (close to zero) or have an affect on the assessment of this regulatory test. DJV's additional modelling of the interregional benefits for alternative 3, based on medium growth, demonstrates this to be the case. For this reason, the AER did not require additional interregional modelling to be undertaken for the other demand growth scenarios.

The gross market benefits consist of two types of benefit that have been estimated for the alternative projects:

1. network deferral benefits
2. interregional benefits.

On balance, the AER considers that the gross market benefits of the alternative projects for the credible scenarios are consistent with the results determined for the sensitivity scenarios. The market simulation indicates that these gross market benefits are:

- $129–257 million for Directlink and alternatives 1 and 2
- $25–36 million for alternative 3. This result reflects that alternative 3 provides no interregional benefits and only a small amount of network deferral benefits.

The total costs of the alternative projects vary with the discount rate because some components of the cash flows occur over time (namely, opex and the IDC). The median costs of the alternative projects for the credible scenarios are the same as the average for the sensitivity scenarios. The net market benefits of Directlink and its alternative projects are determined by subtracting their total costs from the gross

149 Given the range of estimates and the skewed distribution, the median is considered to be a better measure of central tendency.

market benefits. The median net market benefits for the credible scenarios are similar to the median for the sensitivity scenarios.

10.5 Conclusion

For the purposes of applying the regulatory test over a range of market development scenarios and sensitivity analysis, the AER has determined the gross market benefits and total costs of Directlink and its alternative projects. The sensitivity analysis to test key input assumptions, demonstrates that the median results for the credible scenarios are consistent with the median of the sensitivity analysis. The net market benefits over the credible scenarios are shown in table 10.1.

Table 10.1 Net market benefits for credible scenarios ($ million, 1 July 2005)

Credible scenarios				Net market benefits			
USE value	Bidding strategy	Discount rate	Demand growth	Directlink	Alternative 1	Alternative 2	Alternative 3
$29 600	Historical	9%	High	50.1	–34.8	70.0	–64.3
$29 600	Historical	9%	Medium	–24.8	–109.8	–4.9	–61.2
$29 600	Historical	9%	Low	–58.1	–143.1	–38.2	–53.4
$10 000	Historical	9%	High	67.4	–17.5	87.3	–64.3
$10 000	Historical	9%	Medium	–53.8	–138.8	–33.9	–56.1
$10 000	Historical	9%	Low	–61.0	–145.9	–41.1	–53.4

In summary, the results for the credible scenarios vary over a wide range and show the following range of net market benefits:

- –$61 million to +$67 million for Directlink
- –$146 million to –$18 million for alternative 1
- –$41 million to +$87 million for alternative 2
- –$64 million to –$53m for alternative 3.

11 Rankings and establishing the asset value

11.1 Introduction

When the net market benefits for each project have been determined, the results can be ranked for each scenario considered. This ranking will help identify the alternative project, if any, that satisfies the regulatory test. The project that satisfies the regulatory test is the one that maximises the net market benefits in most (although not all) credible scenarios.

This chapter sets out the:

- the ranking of Directlink and its alternative projects (section 11.2)
- principles for establishing an appropriate asset value (section 11.3)
- the AER's considerations (section 11.4)
- the conclusion (section 11.5).

11.2 Ranking of Directlink and its alternative projects

Table 11.1 summarises the ranking of Directlink and its alternative projects under the six credible scenarios identified in chapter 10.

Table 11.1 Net market benefits and rankings for credible scenarios ($ million, 1 July 2005)

Credible scenarios				Net market benefits and rankings							
USE value	Bidding strategy	Discount rate	Demand growth	Directlink (ranking)		Alternative 1 (ranking)		Alternative 2 (ranking)		Alternative 3 (ranking)	
$10 000	Historical	9%	High	67.4	(2)	–17.5	(3)	87.3	(1)	–64.3	(4)
$29 600	Historical	9%	High	50.1	(2)	–34.8	(3)	70.0	(1)	–64.3	(4)
$29 600	Historical	9%	Medium	–24.8	(2)	–109.8	(4)	–4.9	(1)	–61.2	(3)
$10 000	Historical	9%	Medium	–53.8	(2)	–138.8	(4)	–33.9	(1)	–56.1	(3)
$29 600	Historical	9%	Low	–58.1	(3)	–143.1	(4)	–38.2	(1)	–53.4	(2)
$10 000	Historical	9%	Low	–61.0	(3)	–145.9	(4)	–41.1	(1)	–53.4	(2)

Overall, none of the projects satisfy the regulatory test because none maximises the net market benefits in most credible scenarios. In these circumstances, the regulatory test indicates that there is no net benefit in proceeding with any of the projects—that is, Directlink should not be constructed and there is no optimal project identified for replacing Directlink. In this situation, the reference case (identified as alternative 5 by DJV) would be constructed under the first (reliability) limb of the regulatory test. Out of the six scenarios, Directlink and alternative 2 provide positive net market benefits in two scenarios and negative net market benefits (that is, less than zero) for the remaining scenarios. Alternatives 1 and 3 provide negative net market benefits in all six scenarios. Alternative 2 is the project that is closest to satisfying the regulatory test. It is ranked first for all credible scenarios. For sensitivity scenarios, it is also ranked first for all but one scenario (table G.14).

Because no project maximises the net market benefits in most credible scenarios, the regulatory test indicates that there is no optimal project with which to proceed. In the Murraylink decision, at least one alternative project passed the regulatory test. In that decision, the ACCC stated that if no project maximises the net present value of the market benefits under most credible scenarios, then the proponent would not proceed with the proposal.[150]

This result also means that it is unnecessary to consider the alternative approach to applying the regulatory test proposed by the Allen Consulting Group (ACG) in chapter 5. The ACG's proposed approach is intended to compare and adjust for the different benefits between an alternative project and the converting asset, where an alternative project satisfies the regulatory test and provides a different level of benefit.

11.3 Principles for establishing an appropriate asset value

The regulatory test does not provide guidance on how to establish an appropriate asset value for assets that do not satisfy the regulatory test. In these circumstances, a proponent would ordinarily not build the asset.

In chapter 5, the AER considered the general principles that guide the asset valuation decision, including the following:

- A converting asset should not be treated more or less favourably than existing market participants.
- The conversion provision is intended to ensure non-commercial market design risks do not inefficiently inhibit investment.
- The maximum allowed revenue set for the converted network service provider (NSP) need not guarantee a return on the original capital cost, but should be based on the assessed need for the facility at the time of conversion.
- The regulatory regime administered by the AER should foster efficient use of existing infrastructure and an efficient level of investment within the transmission sector.
- The regulatory regime administered by the AER should seek to achieve reasonable consistency over time in the outcomes of regulatory processes
- The regulatory regime administered by the AER should seek to achieve reasonable and well-defined regulatory discretion that permits an acceptable balancing of the interests of transmission network owners, transmission network

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[150] ACCC, *Decision: Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue*, Canberra, 1 October 2003, p. 45.

users and the public interest as required of the ACCC under the provisions of Part IIIA of the *Trade Practices Act 1974* (TPA).

11.4 The AER's considerations

The regulatory test assessment indicated that no project is optimal and that Directlink would not be constructed. One option for the AER, therefore, would be to allow conversion of Directlink with a zero asset value. The AER, however, is of the view that allowing Directlink to convert but providing DJV with a zero asset value would not encourage the efficient use of existing infrastructure, as is required by clause 6.2.2 of the code. Directlink already exists and provides benefits to market participants over and above its operating costs, so an asset value that is greater than zero would be appropriate.

Given the early encouragement offered to MNSPs and the option to potentially obtain regulated status by way of conversion, a decision to provide DJV with a zero asset value may be inconsistent with the intention of the MNSP and conversion provisions of the National Electricity Code (the code). The regulator's treatment of existing assets in such a manner could also be perceived as creating an environment of uncertainty which may have an adverse effect on transmission investment incentives in the future. Because investment is susceptible to uncertainty, it may deter future efficient investments in the long term. The AER is seeking to provide certainty and thereby maintain an environment that is conducive to efficient investment, foster the efficient use of existing infrastructure and achieve reasonable consistency in the outcomes of regulatory processes. In these circumstances, an approach that provides Directlink with an appropriate asset value that is greater than zero means market participants benefit in the long term through the encouragement of ongoing investment in the NEM.

It may be argued that allowing conversion based on the cost of Directlink or one of the alternative projects would be treating the converting asset more favourably than existing market participants. Before constructing a new large network asset, a proponent must apply the regulatory test to demonstrate that the proposed asset is optimal. Further, setting an asset value based on the cost of an alternative project that does not satisfy the regulatory test would be inconsistent with the assessed need for the facility at the time of conversion. It would provide an incentive to undertake investment that is deemed inefficient by a cost–benefit analysis.

The AER considers that it would be appropriate to provide DJV with an asset value greater than zero but less than the cost of Directlink or one of the alternative projects. This approach would accord with the conversion provision's intention, and the objectives of the code and the transmission revenue regulatory regime administered by the AER.

11.4.1 Optimised deprival value

In chapter 5, the AER noted that the regulatory test framework will provide an outcome that is consistent with the optimised deprival value (ODV) method. That is, where an asset is to be replaced, it will be replaced with the asset that maximises the net present value of market benefits. This is equivalent to the asset that has the lowest optimised depreciated replacement cost (ODRC). The results, however, of the regulatory test assessment indicate that the value of Directlink is less than its ODRC. That is, Directlink would not be constructed and no optimal project to replace Directlink was identified. However, the reality is that Directlink has already been constructed and is providing some benefits over and above its operating costs, so an asset value of greater than zero would be appropriate. The AER is of the view that the interests of DJV and market participants can be balanced by further considering the ODV method of asset valuation in the instance where the asset would not be replaced.

This would specifically involve applying the 'economic value' (EV) limb of ODV. Under ODV, EV is defined as the greater of the disposal value or its value to users. As noted in chapter 5, the estimated market benefit provided by Directlink can be regarded as the economic value. EV applies when:

- the rational choice is not to replace the asset
- the asset is worth less than its ODRC.

In this case, EV allows a value to be assigned to Directlink, where the value of current use is equal to or greater than opportunity cost, yet replacement of Directlink would not be economic. As long as Directlink can provide a value to users (as defined by the estimated market benefits) which exceeds its disposal value, EV would capture this market benefit. Accordingly, if Directlink was removed (or 'deprived') from the market, it would not be replaced with any project unless the capital cost was such that it was equal to the total market benefit that it provides—that is, the capital cost of Directlink is optimised to the level of its market benefits. DJV would be provided with a return that is commensurate with the level of market benefits provided by Directlink.

In its decision to authorise the code changes for the conversion provision (as outlined in chapter 5), the ACCC stated that:

> Where the Commission decides a network service may be a prescribed network service, an NSP will require a revenue stream to be determined for that service. The Commission will consider the prudence of the network service at the time the conversion to a prescribed service occurs, rather than consider any earlier investment decisions. As such, the investor would bear the risk of the Commission optimising down the value of the assets – with the consequence of reduced revenue streams, at the time it converted to regulated status and each regulatory review into the future.[151]

Optimising the capital cost of Directlink to reflect its estimated market benefits would be consistent with the ACCC's stated intention of considering the prudence of the network service when the conversion occurs. By reducing the revenue streams in accordance with an optimised regulated asset base, this approach is also in the interests of transmission network users.

There is, however, a degree of uncertainty in measuring market benefits. The value of market benefits of Directlink spans a wide range depending on the assumptions adopted. Therefore, the market benefits need to be estimated for several scenarios.

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[151] ACCC, *Applications for Authorisation: Amendments to the National Electricity Code—Network Pricing and Market Network Service Providers*, Canberra, 21 September 2001, p. 138.

Under the regulatory test framework in chapter 10, the AER considered six credible scenarios. These scenarios reasonably capture the uncertainty which surrounds the future state of the NEM. In particular:

- all demand growth forecasts have been considered reasonably likely to occur
- it is not possible to state whether VENCorp's unserved energy (USE) value of $29 600 per MWh is more or less suitable as a general measure. In the absence of an accurate value for USE, the market value of lost load of $10 000 per MWh should also be used. IES advised the AER that both values need to be considered and given equal weighting.

In determining an EV, it is normal practice to identify the most likely scenario to establish a 'fair value'. As shown in table 11.2, the estimated total market benefits of Directlink span a wide range under the credible scenarios. It is not possible to select the most likely scenario with a reasonable degree of certainty. Therefore, for the purposes of determining the EV of Directlink, the AER considers that the six credible scenarios remain relevant.

Table 11.2 Total estimated market benefits of Directlink ($ million, 1 July 2005)

Credible scenarios				Market benefits of Directlink		
USE value	Bidding strategy	Discount rate	Demand growth	Deferral benefit (a)	Inter–regional benefit (b)	Total benefit (a)+(b) [1]
$10 000	Historical	9%	High	83.3	174.1	257.3
$29 600	Historical	9%	High	83.3	156.8	240.0
$29 600	Historical	9%	Medium	95.6	69.4	165.0
$10 000	Historical	9%	Medium	95.6	40.4	136.1
$29 600	Historical	9%	Low	106.1	25.7	131.8
$10 000	Historical	9%	Low	106.1	22.8	128.9

1 Total benefit may not add exactly due to rounding.

The above results indicate a range of market benefits across the credible scenarios that are highly variable and skewed. The AER, therefore, must exercise care when selecting the most reasonable EV of Directlink. To obtain the highest degree of confidence that the market benefits can be achieved, the lowest EV of $128.9m could be selected. The AER considers, however, that selecting the lowest EV for setting the asset value may be regarded as unfair because Directlink can be expected to deliver higher market benefits under different credible scenarios for which it would not be compensated. This would not be consistent with the principles that the AER must consider, in particular, an acceptable balancing of the interests of transmission network owners and transmission network users.

The AER considers that the best balance to determine an EV that is representative of the credible scenarios is to use the measure of central tendency. Given the range of estimates and the skewed distribution, using a mean to determine a single value is not appropriate because the mean is more affected by extreme values and is therefore not a good measure of central tendency. The median is less sensitive to extreme ranges and this makes it a better measure than the mean for skewed distributions.

In determining the median, the ordered middle value is selected when there is an odd number of scenarios. In this case, there is an even number of scenarios. Therefore, the median is determined to be the mean of the two middle values. That is, the mean market benefits of scenarios 3 and 4 results in a median EV of $150.55m for Directlink.

The AER considers that this approach provides an outcome that is consistent with the ODV method outlined in clause 6.2.3(d)(iv)(A) of the code. It provides an economic valuation of Directlink by setting the asset value to be consistent with the level of its economic market benefits.

11.4.2 Opening asset value

The capital cost of Directlink under the EV assessment is $150.55 million. From this capital cost, the lifecycle operating cost of $20.60 million is deducted to determine the project cost of $129.95 million.[152] The AER will also include an allowance for benchmark equity raising cost (as discussed in appendix H). In summary, if a RAB is yet to be established, the opening asset value should reflect all costs, including a benchmark allowance for the cost of raising the equity. A benchmark allowance of 3.64 per cent, determined on the basis of initial public offering costs, would be capitalised into the asset base. To do this, the benchmark is multiplied by the equity component of the opening asset base to provide an allowance of $1.90 million ($129.95 million × 0.4 × 0.0364). This results in an opening asset value for Directlink of $131.85 million ($129.95 million + $1.90 million).

To model DJV's revenue allowance over the regulatory period more accurately, the aggregate opening asset value needs to be split into individual asset classes. DJV's application broke down the capital costs of the alternative projects into three asset classes (substation, transmission and easement). For the purpose of modelling the revenue allowance for DJV, the AER considers that this split of Directlink's opening asset value into three asset classes is reasonable.

The AER has separated Directlink's actual historical cost into the three asset classes. Given the asset value of $131.85 million is based on the EV of Directlink, the AER has taken this value and applied it proportionally to the actual costs of the three asset classes for Directlink. Table 11.3 sets out the split-up of the aggregate asset value of $131.85 million, along with the standard asset lives adopted for determining the depreciation allowance.

[152] See chapter 12 for a discussion of the AER's decision on the opex allowance.

Table 11.3 Opening asset value with standard asset classes and lives

Asset classes	Asset value ($ million, 1 July 2005)	Standard asset lives (years)
Substation costs	79.51	40
Transmission costs	52.34	50
Easement costs	na	na
Total capital cost	131.85	–

na - not applicable.

In the Murraylink decision, the ACCC adopted the full capital cost of the alternative project as the opening asset value. It then depreciated the asset over the standard life of the new asset rather than the life of the actual asset in service. This simplified approach was justified on the basis of the Murraylink asset being relatively new and having been in service for only around 12 months at the time of its conversion. The AER notes that Directlink will have been in service for about five years, so it is appropriate to depreciate (that is, using straight-line depreciation) the opening asset value to reflect Directlink's time in service. This adjustment is consistent with the approach proposed by DJV and provides a depreciated opening asset value of $116.68 million, with remaining asset lives as shown in table 11.4.

Table 11.4 Depreciated opening asset value with standard asset classes and remaining lives

Asset classes	Asset value ($ million, 1 July 2005)	Remaining asset lives (years)
Substation costs	69.57	35
Transmission costs	47.11	45
Easement costs	na	na
Total capital cost	116.68	–

na - not applicable.

11.5 Conclusion

The economic value of Directlink under an optimised deprival value approach is $150.55 million. From this value, the lifecycle operating cost of $20.60 million is deducted to determine a value of $129.95 million. To this amount, the AER has included an allowance for benchmark equity raising costs of $1.90 million. Given that Directlink would have been in service for about five years, it is appropriate to depreciate the adjusted economic value. This is consistent with the approach proposed by DJV and provides a depreciated opening asset value of $116.68 million. This asset value will be used to determine the maximum allowed revenues for DJV.

The AER acknowledges that it is a difficult task to determine an appropriate asset value for Directlink. The AER, however, is of the view that the approach it has employed in determining the opening asset value is appropriate and robust. Nevertheless, it is important to consider wholistically whether the value of $116.68 million is fair and reasonable in all circumstances.

The proposed asset value represents a modest optimisation of the capital originally employed by DJV. It represents approximately 80 per cent of the actual depreciated cost of Directlink (that is, $147 million). Regulators should exercise caution when proposing to optimise actual capital costs because of the potential to deter future investment. In the current case, however, there are reasons to believe that the proposed optimisation is appropriate and unlikely to affect incentives for future efficient investment.

Directlink's circumstances are unique and the optimisation that has been applied to Directlink has arisen from these unique circumstances. It would not be expected to be universally applied. The optimisation is consistent with the intention of the conversion provision, which specifies that MNSPs should not be quarantined from the financial consequences of their investment decisions.

The AER considers that special compensation is not warranted for the commercial risks faced by Directlink. The risks encountered by Directlink ought to have been known at the time of construction and factored into that decision. MNSPs earn revenue by arbitraging the price differential between two regions. As such a major commercial risk facing MNSPs is the potential for the development of an alternative interconnector which would erode the arbitrage opportunities. In Directlink's case, the Queensland – New South Wales Interconnector (QNI) was commissioned by TransGrid and Powerlink in February 2001. QNI offered substantially more capacity than Directlink and effectively eliminated much of the price differential between the NSW and Queensland electricity regions.

Directlink came into operation on 25 July 2000. Plans for the construction of QNI were identified in the National Electricity Code (the code) in November 1998—well in advance of the commissioning of Directlink and prior to the owners awarding the equipment supply contract for Directlink to ABB.[153] In March 1999, NEMMCO published the proposed transfer capacity of QNI—500 MW from NSW to Queensland and 1000 MW from Queensland to NSW—and its proposed commissioning date of December 2000.[154] As such the risks posed by QNI ought to have been accommodated in the construction decision for Directlink.

Even though the AER has applied a modest optimisation it is likely that a maximum allowed revenue based on a proposed asset value of $116.68 million will be more than the revenue that DJV is currently earning in the market (based on the figures contained in Country Energy's annual reports).

The AER notes that no alternative project satisfied the regulatory test. As such, neither Directlink, nor any project similar to Directlink, would be justified at the time of conversion. However, Directlink has already been constructed and is providing benefits to the market.

Applying an EV provides an asset value that is consistent with the level of market benefits provided by Directlink. The AER considers that estimating market benefits

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[153] National Electricity Code, version 1, chapter 9, 19 November 1998, section 9.38.4.

[154] National Electricity Market Management Company, *Statement of Opportunities*, 31 March 1999, p. 83.

with regard to a range of market development scenarios provides a fair and reasonable asset value for Directlink. It ensures that Directlink is able to receive an allowance for the benefits it provides to the market. In estimating the benefits offered by Directlink the AER has assumed an availability of 99 per cent for 120 MW. However, Directlink has had a history of technical and reliability issues and it has not yet been confirmed that Directlink can achieve the assumed level of reliability.[155] As such, the benefits calculated could be considered to be an upper bound.

In setting the asset value, the AER is required to have regard to the relevant sections of the code. The AER considers that applying an EV to set an asset value for Directlink is consistent with the objectives of the transmission revenue regulatory regime in clause 6.2.2 of the code. It fosters efficient use of existing infrastructure and investment in transmission infrastructure as well as balancing the interests of network owners, network users and the public. EV also provides an asset value that does not exceed the deprival value of the asset.

If the AER was to value Directlink in the absence of the regulatory test or any information contained in DJV's application for conversion, it would look to the value of similar assets in the market for guidance. The AER notes that the least cost of constructing a new DC link along Directlink's route would be approximately $157 million. In addition, a preliminary estimate of the cost of upgrading QNI was recently found to be $120 million.[156]

The AER notes, however, that the conversion of Directlink is an option for DJV and that DJV may choose to continue operating as a market network service.

For these reasons, the AER considers that using the EV limb of the ODV method to set an asset value for Directlink provides a robust outcome. The proposed asset value of $116.68 million is a fair and reasonable result under these circumstances.

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155 PB Associates, *Review of Directlink Conversion Application: Final Report*, Port Macquarie, November 2004, p.5.

156 Powerlink–TransGrid, *Queensland–New South Wales Interconnector (QNI) Upgrade Benefits—A Pre-Feasibility Study: A Report on Outcomes of Joint Planning Investigation*, 7 October 2005, p.8.

Part D – Revenue cap decision

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12 Operating and maintenance expenditure

12.1 Introduction

This chapter reviews the operating and maintenance expenditure (opex) estimates for Directlink and its alternative projects. It sets out:

- the code requirements (section 12.2)
- DJV's application (section 12.3)
- submissions and the consultancy report (section 12.4)
- the AER's considerations (section 12.5)
- the conclusion (section 12.6).

12.2 Code requirements

The AER's task in assessing DJV's opex is specified in the code. Once a network service provider (NSP) converts to a prescribed service, clause 2.5.2(c) of the code requires that the AER may adjust the revenue cap of that NSP in accordance with chapter 6 of the code. In particular, part B of chapter 6 requires that:

- in setting the revenue cap, the AER must account for the transmission network service provider's (TNSP) revenue requirements, having regard to the potential for efficiency gains in expected operating, maintenance and capital costs, considering expected demand growth and service standards
- the regulatory regime must seek to achieve efficiency in the use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment.

12.3 DJV's application

DJV provided opex estimates for Directlink and its alternative projects based on BRW's advice. The annual opex forecasts for these projects reflect the ongoing costs over an assumed asset life of 40 years. The opex for the direct current (DC) alternative projects (Directlink and alternatives 1 and 2) are the same (table 12.1), while the opex for the alternating current (AC) alternative project (alternative 3) is slightly lower, reflecting the less complex nature of the equipment associated with that alternative.

Table 12.1 DJV’s estimated opex costs for Directlink and its alternatives projects ($ million, 1 July 2005)

Opex items	Directlink, alternatives 1 and 2	Alternative 3
General management (with assistant)	0.31	0.31
Operating management	0.20	0.20
Operations	0.62	0.62
Commercial/regulatory	0.20	0.20
Financial management (with assistant)	0.22	0.22
Maintenance costs	0.36	0.29
Audit fees	0.03	0.03
Legal fees	0.05	0.05
Insurance	0.31	0.19
Energy	0.31	0.31
Communications	0.16	0.16
Corporate overheads	0.10	0.10
Other costs	0.05	0.05
Total	2.92	2.73

12.3.1 Benchmark financing costs

In addition to the above cost items, DJV has requested that the allowed revenue include an allowance for benchmark debt and equity raising costs as part of its opex. (This request is discussed in appendix H.) It has claimed benchmark debt and equity raising costs of around $0.3 million per year, comprising:

- a debt raising cost of 0.25 per cent per year multiplied by 60 per cent of the regulated asset base (RAB)
- an equity raising cost of 0.212 per cent per year multiplied by 40 per cent of the RAB.

12.4 Submissions and the consultancy report

12.4.1 Review of DJV’s estimates of operating and maintenance expenditure

In assessing DJV’s opex estimates, the AER is required to make informed decisions on the adequacy, efficiency and reasonableness of the opex proposed by DJV to meet present and future service requirements. Parsons Brinckerhoff Associates (PB Associates) was engaged to review the appropriateness of DJV’s opex estimates for the regulatory test and in determining the allowed revenue. It recommended that an efficient level of opex would be $1.56 million per year for Directlink and alternatives 1 and 2. Tables 12.2 sets out its findings on DJV’s opex estimates for Directlink and alternatives 1 and 2, including comments on the individual opex items.

Table 12.2 PB Associates' review of opex items

Opex items	Comments
General management (with assistant)	A cost of $0.31 million per year indicates one person full time involved in the general management of Directlink. Given the nature of the facility, and that the facilities are unstaffed for the majority of the time, this appears excessive. PB Associates considers that a figure of **$0.08 million per year** is more appropriate.
Operating management	A cost of $0.2 million per year indicates full use of an engineer for the year, and PB Associates considers that this is reasonable.
Operations	A cost of $0.62 million per year indicates three full time persons, at $.08 million per year, assuming a 2.5 labour multiplier. PB Associates understands that current operations are incorporated into Country Energy's existing control centre and, therefore, that these costs are incremental to Country Energy's system operation costs. It requested, but has not received, proof that these direct operation costs are being incurred. This figure appears excessive, and PB Associates has formed the opinion that Country Energy's operators are likely to spend only a fraction of their time (approximately 10 minutes per hour) directly observing and operating the Directlink system. This equates to approximately **$0.1 million per year**.
Commercial/regulatory	DJV indicated an amount of $0.2 million per year. This is the equivalent of a full time person for this role, which would appear excessive when considered in addition to financial, legal, audit, management and operational resources. PB Associates considers a figure of **$0.03 million per year** is more reasonable.
Financial management (with assistant)	An amount of $0.22 million per year is allocated for financial management. Given the additional financial reporting requirements needed to accommodate the Directlink business, this figure appears reasonable when read in conjunction with the above comments on commercial/regulatory expenses.
Maintenance costs	A cost of $0.36 million per year for all planned and unplanned maintenance/emergency response, including location and repair of any cable faults or equipment failures, appears reasonable.
Audit fees	The proposed amount of $0.03 million per year appears reasonable.
Legal fees	The figure presented by DJV of $0.05 million per year appears reasonable given the complex nature of the market in which Directlink is operating and its unique market participation.
Insurance	The insurance figure provided of $0.31 million per year appears reasonable in relation to the initial construction costs and risks.
Energy	This cost of $0.31 million per year is considered reasonable, based on average retail energy rates.
Communications	High speed, dedicated point-to-point digital communication lines can be expensive, especially if higher than normal reliability is sought. PB Associates considers the cost of $0.16 million to be reasonable.
Corporate overheads	Considering that management, commercial/ regulatory, financial, auditing, legal and insurance expenses are separately listed, the residual overheads amount should be minimal. It would seem unreasonable, therefore, to include an additional $0.10 million per year for corporate overheads. A figure of **$0.05 million per year** is more appropriate.
Other costs	Other costs are not explained and, although only $0.05 million per year, are difficult to accept as reasonable. PB Associates consider that **$0.01 million per year** would be more appropriate.

12.4.2 Operating and maintenance expenditure based on 2 per cent of construction cost

For alternative 3, PB Associates estimated an annual opex of $0.49 million based on 2 per cent of the asset's construction costs. It considered that this is a reasonable and realistic estimate for a project of this type. In response to PB Associates' report, DJV noted that the consultancy had incorrectly summed its own estimates of the opex for Directlink and alternatives 1 and 2, and that the estimates actually sum to $1.92 million. DJV stated that it benchmarked the opex items of general management, operations, commercial/regulatory and financial management with the costs incurred by the Murraylink Transmission Company. It considered that the benchmarking exercise confirmed that its estimates of the opex for Directlink and alternatives 1 and 2 are reasonable.

DJV argued that PB Associates has erred in estimating the annual opex of alternative 3 by basing its analysis on 2 per cent of the asset's construction costs. It stated that PB Associates' estimate is not a better estimate than the one determined by examining the specific locational and technical characteristics of each alternative project, as BRW has done.

12.5 The AER's considerations

In reaching its decision on the appropriate amount of opex to be allowed, the AER has considered the review undertaken by PB Associates and the comments of DJV.

12.5.1 Operating and maintenance expenditure based on 2 per cent of construction cost

PB Associates' review of the opex for alternative 3 recommended an estimate based on 2 per cent of its construction costs. DJV raised concern about the appropriateness of adopting a benchmarking approach to setting opex based on a percentage of the asset value. The AER is aware that a 2 per cent operating cost is typically used and accepted as a reasonable basis for estimating the opex for future network augmentations. PB Associates provided additional information in its letter of 21 March 2005, which argued that the 2 per cent rule for opex is a conservative estimate. It indicated that incremental routine maintenance and inspection costs are highly predictable and that the fixed operating costs do not vary much with the addition of new network assets (although this would depend on the scale of the operations managed by the TNSP).

Although DJV had concerns about benchmarking, it stated that its benchmarking of several opex items with those incurred by the Murraylink Transmission Company confirmed the opex estimates for Directlink and alternatives 1 and 2. The AER has also compared some of the specified opex items with those in the Murraylink Transmission Company's regulatory accounts, but this comparison does not appear to provide clear guidance as claimed by DJV.

The Statement of Principles for the Regulation of Electricity Transmission Revenues (8 December 2004) noted that the development of benchmarks has merit, because it would allow expenditure allowances to be established without necessarily having to conduct exhaustive, firm-specific cost analyses.[157] Considerable work would need to be done, however, to establish reliable benchmarks that produce fair and balanced comparisons across TNSPs. Given, however, that such benchmarks have not yet been developed, the AER will not solely rely on benchmarking except to the limited extent noted in this chapter (for example, for debt raising cost). Rather, benchmarks have been used as a secondary test of the estimates provided by DJV. Accordingly, the breakdown of estimated costs provided by DJV has been reviewed as the basis for determining the appropriate opex for Directlink and alternatives 1, 2 and 3.

12.5.2 Review of operating and maintenance expenditure breakdown for Directlink and alternatives 1, 2 and 3

DJV's application provided a breakdown of the estimated opex of Directlink and alternatives 1, 2 and 3. PB Associates reviewed this information and agreed with a number of the opex items as estimated by DJV. It adjusted the estimate of other items (general management, operations, commercial/regulatory, corporate overheads and other costs) based on its assessment of what resources are likely to be needed to operate and maintain the assets.

In relation to the general management item, PB Associates recommended $0.08 million per year is more appropriate because the assumption of one person (with assistant) full time appears excessive when the facilities are unstaffed for the majority of the time. The AER considers that it would be appropriate to adopt PB Associates' estimate because that figure is more consistent with the reasonable costs of operating and maintaining the asset. It considers that the use of one person on a full time basis per year for this general management role is not necessary, so instead will allow for $0.08 million per year.

In reviewing the operations item, PB Associates indicated that Country Energy's control centre undertakes the task of observing and operating the link, so these costs are incremental to Country Energy's system operation costs. It also indicated DJV, despite a request, had not provided it with any evidence that operation costs of $0.62 million per year are being incurred. PB Associates considered this figure is excessive and should be reduced to $0.1 million given that the operators are likely to spend only a fraction of their time observing and operating the system. The AER considers that PB Associates' recommended figure is reasonable and would be appropriate to adopt for the operations item.

PB Associates noted that DJV's proposed cost for the commercial/regulatory item equates to a full time person for this role and is extreme. The AER considers that this advice is reasonable and that DJV's proposed cost for this item is excessive when considered in addition to separately listed items such as financial, legal, audit and management. The commercial/regulatory role is for a single, small link and would have overlap or synergies with these cost items. The AER thus considers an allowance of $0.03 million per year is appropriate.

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[157] ACCC, *Statement of Principles for the Regulation of Electricity Transmission Revenue*, Canberra, 8 December 2004, p. 67.

For the corporate overheads item, PB Associates noted that the overheads and residual amounts should be minimal because management, financial, commercial/regulatory, auditing, legal and insurance are items that have been separately listed. It recommended a figure of $0.05 million per year instead of $0.1 million as proposed by DJV. The AER considers PB Associates' recommended figure is reasonable and will adopt it for the corporate overheads item.

PB Associates stated that DJV had not explained the inclusion of the 'other costs' item and that an amount of $0.01 million is more appropriate. Given the number of opex items listed, the 'other costs' item should be minimal because the necessary opex cost items have already been identified. The AER thus considers PB Associates' recommended figure is reasonable and will adopt it for this item.

Table 12.3 summarises the AER's adjustments to the annual opex cost items.

Table 12.3 Summary of the AER's opex adjustments ($ million, 1 July 2005)

Cost item	DJV's proposal	AER's decision
General management (with assistant)	0.31	0.08
Operations	0.62	0.10
Commercial/regulatory	0.20	0.03
Corporate overheads	0.10	0.05
Other costs	0.05	0.01

Having reviewed the breakdown of the proposed opex and made the relevant adjustments, the AER considers an annual opex of $1.92 million is appropriate for the direct current (DC) projects (Directlink and alternatives 1 and 2). In assessing the similar breakdown of opex items for alternative 3 (table 12.1) with those estimated for the DC projects, the AER considers the adjustments for the opex items (general management, operations, commercial/regulatory, corporate overheads and other costs) also apply to alternative 3. It thus considers an annual opex of $1.72 million is appropriate for alternative 3. For the regulatory test assessment, the appropriate opex allowances for Directlink and its alternative projects are summarised in table 12.4.

Table 12.4 The AER's conclusion on opex for Directlink and its alternative projects ($ million, 1 July 2005)

		Directlink, alternatives 1 and 2	Alternative 3
DJV's proposal	Annual opex	2.92	2.73
	Lifecycle opex[a]	31.40	29.30
AER's decision	Annual opex	1.92	1.72
	Lifecycle opex[a]	20.60	18.45

(a) The lifecycle opex amount has been calculated as the present value of the annual opex required over the assumed life of the asset (40 years), based on a 9 per cent discount rate.

12.5.3 Operating and maintenance expenditure to be included in the allowed revenues

The allowed revenue for DJV will be set by reference to the optimised project cost and efficient opex for Directlink. The AER considers an appropriate opex allowance would be around $2 million per year, as shown in table 12.5.

Table 12.5 The AER's opex allowance for DJV ($ million, 1 July 2005)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
DJV's proposal [(a)]	3.24	3.23	3.22	3.22	3.21	3.41	3.40	3.18	3.18	3.17
AER's opex	1.92	1.92	1.92	1.92	1.92	1.92	1.92	1.92	1.92	1.92
add Increase for replacement cost						0.20	0.20			
add Debt raising cost	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.05
AER's decision[(b)]	1.99	1.99	1.99	1.99	1.98	2.18	2.18	1.98	1.98	1.97

(a) DJV's proposal includes debt and equity raising costs.

(b) The AER's decision for opex includes debt raising costs, but equity raising costs are provided for in the RAB.

Benchmark financing cost

As outlined in appendix H, the AER will provide an allowance to DJV for benchmark debt and equity raising costs. The allowance for equity raising costs was discussed in chapter 11. In summary, a benchmark allowance of 3.64 per cent ($1.9 million) is included in the opening asset value of $131.85 million and depreciated over the life of the asset. The debt raising costs are included as part of the annual opex allowance in the determination of DJV's allowed revenue over the regulatory period (table 12.5). The allowance for these costs is calculated by multiplying the benchmark costs (10.4 basis points per year), the gearing ratio and the opening depreciated asset value. DJV's opening depreciated asset value is $116.68 million and the assumed benchmark gearing ratio is 60:40, so debt raising costs averaging about $0.06 million per year are allowed over the 2005–06 to 2014–15 regulatory period.

Equipment replacements

DJV's proposed opex includes an increase of $0.2 million for each of 2010–11 and 2011–12. BRW stated that the opex costs are for typical years and would require such an increase for two years for some equipment replacements on a 10 year cycle. While recognising that more opex may be required when an asset ages, the AER has not received any other information to determine whether this proposed increase is appropriate. For this draft decision, therefore, it proposes to provide an additional amount of $0.2 million for both 2010–11 and 2011–12.

12.6 Conclusion

In determining the allowed revenue for DJV, the AER considers that an opex allowance of around $2 million per year is reasonable (table 12.6). The total allowance is about $20 million over the 2005–06 to 2014–15 regulatory period.

Table 12.6 The AER's conclusion on the opex allowance for DJV ($ million, 1 July 2005)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
DJV's proposal[(a)]	3.24	3.23	3.22	3.22	3.21	3.41	3.40	3.18	3.18	3.17
AER's decision[(b)]	1.99	1.99	1.99	1.99	1.98	2.18	2.18	1.98	1.98	1.97

(a) DJV's proposal includes debt and equity raising costs.

(b) The AER's decision for opex includes debt raising costs, but equity raising costs are provided for in the RAB.

13 Cost of capital

13.1 Introduction

This chapter provides an estimate of an efficient benchmark cost of capital or weighted average cost of capital (WACC) that DJV is likely to face when financing its transmission business over the regulatory period. The WACC is used in conjunction with the regulated asset base (RAB) to determine the return on capital.

The remainder of this chapter sets out:

- the code requirements (section 13.2)
- the background and formula for the WACC (section 13.3)
- DJV's application (section 13.4)
- the conclusion (section 13.5).

Appendix H contains considerations regarding individual parameters of the WACC.

13.2 Code requirements

An objective of economic regulation is to provide a fair and reasonable rate of return to transmission network service providers (TNSPs) on efficient investment, given efficient operating and maintenance practices (clause 6.2.2(b)(2) of the code). Clause 6.2.4(c)(4) of the code states that the AER must determine the WACC of a TNSP with regard to the risk adjusted cash flow rate of return required by investors in commercial businesses facing business risks similar to those faced by TNSPs.

13.3 Background

Electricity transmission is a highly capital intensive industry where return on capital generally accounts for about half of the allowed revenue. Relatively small changes to the cost of capital can have a substantial impact on the allowed revenue.

Correctly assessing the WACC is important because:

- if the return on equity is too low, the regulated network may be unable to earn sufficient returns for the owner. This could reduce the incentive to re-invest in the business.
- if the return on equity is too high, networks may have a strong incentive to overcapitalise, creating inefficient investment
- a higher allowed revenue means higher prices for end users.

In its 2004 *Statement of Principles for the Regulation of Electricity Transmission Revenues—Background Paper* (the SRP), the Australian Competition and Consumer Commission (ACCC) outlined the appropriate expression of the rate of return to be achieved and how it has used that expression for deriving the allowed revenue in previous regulatory decisions:

> The ACCC has historically adopted a WACC which is the weighted average of the nominal post-tax return on equity and nominal pre-tax cost of debt. This is known as the nominal vanilla WACC. The vanilla WACC does not include the impact of business income tax.[158]

The nominal vanilla WACC formula for this decision is:

$$\text{WACC} = r_e\,(E/V) + r_d\,(D/V)$$

where:

r_e	=	the required rate of return on equity or cost of equity
r_d	=	the cost of debt
E	=	the market value of equity
D	=	the market value of debt
V	=	the market value of equity plus debt.

The ACCC explicitly models the tax liabilities of a TNSP in the cash flow model, and the AER proposes to adopt the same method for this case in the post-tax revenue model (PTRM).

13.4 DJV's application

DJV has used the ACCC's post-tax approach to setting the WACC, expressed in nominal terms.

13.5 Conclusion

In the SRP, the ACCC proposed to establish the WACC on the basis of benchmark parameters and to enhance certainty in investments. It also undertook, however, to carry out further review and monitoring in this area in close consultation with industry and user groups, and to exercise judgment in its application of empirical evidence from the market.

The AER has adopted the post-tax approach to setting the WACC, as proposed by DJV. In making its decision, it has considered:

- DJV's application, submissions and the SRP
- the values that should be assigned to DJV's cost of capital, given current market circumstances.

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[158] ibid., p. 87.

Appendix H sets out the considerations regarding individual parameters of the WACC adopted for this draft decision (table 13.1). Some parameters vary over time according to market conditions. They have been calculated as at 28 October 2005. For the draft decision, the AER considers a nominal vanilla WACC of 8.40 per cent provides an appropriate cost of capital for DJV. As part of finalising its decision, it will update the WACC for the prevailing market bond yields.

Table 13.1 Comparison of cost of capital parameters

Parameter	**DJV's proposal**	**The AER's draft decision**
Nominal risk-free interest rate (r_f)	5.54%	5.50%
Real risk-free interest rate (rr_f)	2.94%	2.64%
Expected inflation rate (f)	2.53%	2.79%
Debt margin (d_m)	1.50%	0.84%
Cost of debt ($r_d = r_f + d_m$)	7.04%	6.34%
Market risk premium ($r_m - r_f$)	6.00%	6.00%
Gearing (D/V)	60%	60%
Value of imputation credits γ	50%	50%
Asset beta β_a	0.45	na
Debt beta β_d	0.00	na
Equity beta β_e	1.13	1.00
Nominal post-tax return on equity	12.32%	11.50%
Post-tax nominal WACC	na	6.79%
Pre-tax real WACC	na	5.93%
Nominal vanilla WACC	**9.16%**	**8.40%**

na Not available.

14 Service standards

14.1 Introduction

Under a revenue cap regime, transmission network service providers (TNSPs) are unable to increase their revenue above the maximum allowed revenue. The only way that TNSPs can increase their profits (for regulated activities) is by reducing their costs. But such cost reductions could result in a decline in service quality, which could impose costs on other market participants. As a result of these incentives, the AER sets service standards to maintain the quality of service.

The remainder of this chapter sets out:

- the code requirements (section 14.2)
- service standards guidelines (section 14.3)
- the AER's draft decision (section 14.4).

14.2 Code requirements

Clause 6.2.4(a) of the code provides that the form of economic regulation may account for the performance of the TNSP under its service standards. In setting a revenue cap to apply to DJV, the AER is required to account for DJV's revenue requirements, having regard for:

- demand growth that the TNSP is expected to service (clause 6.2.4(c)(1))
- service standards referred to in the code that apply to the TNSP, along with any other standards imposed on the TNSP by any regulatory regime administered by the AER or by agreement with the relevant network users (clause 6.2.4(c)(2))
- the potential for the TNSP to realise efficiency gains in expected operating, maintenance and capital costs, accounting for the expected demand growth and service standards noted in clauses 6.2.4(c)(1) and (2) (clause 6.2.4(c)(3)).

Clause 6.5.7(b) requires each TNSP to publish its applicable service standards. Clause 6.2.5 provides for the AER to prescribe the information to be provided by TNSPs, which the AER may use to set revenue caps and publish annual performance statistics on the service standards.

14.3 DJV's application

DJV proposed that the performance measure of circuit availability captures all of Directlink's appropriate service attributes. DJV proposed 48 hours per annum of planned outages and 67.11 hours per annum for peak and off-peak forced outages. DJV also proposed that one per cent of the allowed revenue be placed at risk as an incentive to meet these performance levels and that a review of its performance scheme should take place five years after the determination takes effect.

14.4 Service standards guidelines

In November 2003, the ACCC released its service standards guidelines. The AER re-issued the guidelines on 22 August 2005, setting out:[159]

- a performance incentive scheme that the AER intends to apply as part of revenue cap decisions
- the information to be provided by a TNSP in its revenue cap application and on an annual basis.

The guidelines are based on a consultancy report produced by Sinclair Knight Merz in 2003. The consultancy did not identify any measures as being applicable to Directlink because, at the time of the consultancy, Directlink was not applying to become a regulated interconnector.

The performance incentive scheme is based on five performance indicators:

1. availability
2. loss of supply index
3. outage duration
4. intra-regional constraint
5. interregional constraint.

Generally, the average performance during the previous three to five years becomes the performance benchmark or target in setting a financial incentive for service standards. TNSPs are rewarded for improvements in service standards above the performance target and penalised for deteriorations. For all revenue cap decisions set by the ACCC, the maximum reward or penalty is set at up to 1 per cent of the allowed revenue.

The service standards guidelines require TNSPs to report on service standard performance on a calendar year basis. This approach allows for any reward/penalty to be included in a TNSP's price setting for the next financial year.

14.5 Conclusion

In summary, the AER considers that:

- the applicable performance measure is 'circuit availability', which comprises three submeasures: scheduled, peak forced and off-peak forced
- in accordance with clause 6.2.5 of the National Electricity Rules and the service standards guidelines, all measures should be recorded and reported annually

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159 AER, *Compendium of Electricity Transmission Regulatory Guidelines*, Melbourne, 22 August 2005.

based on calendar years. Experience indicates that the report should be provided by the end of January each year for the preceding calendar year, to enable the maximum allowed revenue to be determined for the following financial year.

Appendix I details the AER's consideration of the performance incentive scheme to apply as part of DJV's revenue cap, and the AER's conclusion.

15 Pass-through mechanism

15.1 Introduction

A pass-through mechanism allows a transmission network service provider's (TNSP) revenue to be adjusted for expenditure by the TNSP during the regulatory period when a specified risk eventuates. Chapter 6 of the background paper to the ACCC's *Draft Statement of Principles for the Regulation of Electricity Transmission Revenues* (draft SRP), dated 18 August 2004, discussed the issues of risk management.

In summary, asymmetric specific risks could be compensated for by:

- external insurance, with the cost of the insurance policy included in the operating and maintenance (opex) allowance
- self-insurance, with a notional insurance premium included in the opex allowance
- pass-through mechanism, which forms part of the revenue cap
- a re-opening of the revenue cap, where permitted by the National Electricity Code (the code)/the National Electricity Rules.

Under a pass-through mechanism, if the specified risk (the pass-through event) occurs, the maximum allowed revenue is adjusted for the resulting impact on the TNSP's expenditure, whether opex or capital expenditure (capex). As the costs of the event are passed through, the mechanism transfers risk from the TNSP to users.

This chapter sets out:

- the code requirements (section 15.2)
- DJV's proposed pass through mechanism (section 15.3)
- submissions (sections 15.4)
- the ACCC's *Statement of Principles for the Regulation of Electricity Transmission Revenues* (SRP) and New South Wales (NSW) revenue cap decisions (section 15.5)
- AER's considerations (section 15.6)
- the conclusion (section 15.7).

15.2 Code requirements

Clauses 6.2.2–6.2.4 of the code set out the provisions relevant to the AER's assessment of DJV's pass-through application:

- Clause 6.2.4(a) provides that economic regulation is to take the form of the consumer price index (CPI) – X (or some incentive based variant). The AER is required to judge the potential for efficiency gains (clause 6.2.4(c)(3)) and to have regard to the need to provide DJV with incentives to increase efficiency (clause 6.2.3(d)(1)) (see also clauses 6.2.2(b) and 6.2.2(d)–(f)).

- The AER is also required, however, to account for the revenue requirements of DJV, having regard to the provision of a return on efficient investment and operating expenditure (clauses 6.2.4(c)(5), 6.2.3(d)(4) and 6.2.2(b)(2)), service standards (clauses 6.2.4(c)(2) and 6.2.4(c)(3)), taxes (clauses 6.2.4(c)(6)), network support service payments to generators (clause 6.2.4(c)(7)) and the ongoing commercial viability of the transmission industry (clause 6.2.4(c)(8)).

- In addition, the AER must have regard to the need to provide certainty and consistency in regulatory processes, balance the interests of users and TNSPs, and minimise the costs of regulation (clauses 6.2.3(d)(5), 6.2.2(a) and 6.2.2(i)–(k)).

The application of the code provisions in the context of pass-through mechanisms is discussed below.

15.3 DJV's application

In appendix H of its revised conversion application (dated 22 September 2004), DJV proposed that a pass-through mechanism would operate for four categories of events:

1. service standards event
2. change of tax event
3. terrorism event
4. insurance event.

15.4 Submissions

Following DJV's initial application (dated 6 May 2004), the ACCC received submissions on this issue from the Energy Users Association of Australia (EUAA) (dated 17 June 2004) and DJV (dated 24 August 2004). In summary, EUAA stated that:

- businesses in a competitive environment could not pass through such costs to their consumers

- Directlink is unlikely to pass through any cost reductions to consumers, and end users would be left with only downside risks. If pass-through provisions are allowed, the rules should also allow end users or their representatives to seek pass-through of any cost reductions.

In response to the EUAA's submission, DJV stated that:

- some risks are outside a TNSP's control or management and could substantially increase its costs. TNSPs would not be compensated for accepting the full financial impact of these extreme events.

- the rules that it proposes allow the AER or DJV to bring about the pass-through of cost reductions as well as cost increases.

15.5 The *Statement of Regulatory Principles* and NSW revenue caps

The conversion application process for DJV has been conducted concurrently with the ACCC's review of its *Draft Statement of Principles for the Regulation of Transmission Revenues* (dated 27 May 1999). On 18 August 2004, the ACCC released its proposed revised statement of regulatory principles (the draft SRP). Chapter 6 of the background paper to the draft SRP discussed the ACCC's approach to the use of pass-through mechanisms to address asymmetric specific risks.

In relation to pass-through applications, the ACCC considered that a pass-through event should generally have the following characteristics:

- It should be identified in advance, with its scope precisely defined.
- It should be beyond the control of the TNSP.
- Its financial impact should be better borne by parties other than the TNSP.
- It should affect the TNSP, but not the market generally.
- It should not already be compensated for in the forecast opex or other revenue cap costs.
- It should not be more efficient for the TNSP to insure against the risk.
- Its financial impact should be material.

Section 6.7 of the draft SRP also set out features that the ACCC considered should generally be included in the pass-through rules. It noted too that the ACCC, to assist TNSPs, had developed a standardised set of pass-through rules. These draft rules were developed to facilitate a consistent approach across revenue caps and to provide greater certainty for TNSPs and other parties.

In summary, the approach set out in the draft SRP was considered to be consistent with the code provisions for the following reasons:

- Although the code creates an incentive based regime, certain events do not necessarily lend themselves to incentive regulation. Pass-through rules provide a mechanism for dealing with events that are beyond the control of the TNSP where the costs cannot be built into a TNSP's expenditure forecasts but may have a significant financial impact on the TNSP. Limiting pass-through events to exogenous, unpredictable events (and adjusting the pass-through amount if the TNSP acts inconsistently with good electricity industry practice) balances the revenue requirements (and commercial viability) of the TNSP against the requirement to administer an incentive based regime, the need to provide efficiency incentives and the interests of other parties.

- Precisely defining the scope of the pass-through events and adopting a standard approach (where appropriate) promotes certainty and transparency. Setting a materiality threshold reduces the administrative cost of regulation.

The submissions received by the ACCC in response to the draft SRP are summarised in section 7.5 of the background paper (dated 8 December 2004). In chapter 7 of that document, the ACCC brought together the pass-through arrangements that had previously been discussed separately in the opex and capex sections of the draft SRP.

The ACCC recognised the limitations of including pass-through rules as part of a revenue cap, particularly:

- the difficulty of distinguishing between endogenous and exogenous costs
- the difficulty of defining the exogenous events with sufficient precision for the purpose of the pass-through rules
- the difficulty of calculating the extent to which risks have been compensated in the decision of allowed expenditure and returns that could result in consumers paying the same cost twice
- the legal limitations in the drafting of pass-through rules that form part of the final decision setting a revenue cap.

Consequently, the SRP set out the ACCC's preference not to include pass-through rules in a revenue cap but to instead seek amendment to the code to allow revenue caps to be re-opened within a regulatory period. Under clause 6.2.4(d) of the code, revenue caps could be re-opened only in limited circumstances. In section 7.2 of the SRP, the ACCC considered that the code should be amended to allow the revenue cap to be re-opened subject to the following conditions:

- the TNSP being materially adversely affected by the event
- the event being beyond the TNSP's control
- the event not having been contemplated at the time the revenue cap decision was made
- the benefits of revoking the revenue cap outweighing the detriment to the TNSP's customers from revoking the cap.

The code amendment was not in place on 27 April 2005 when the ACCC set the revenue caps to apply to the NSW and Australian Capital Territory transmission network from 1 July 2004 to 30 June 2009. Consequently, for the reasons set out in chapters 4.10 and 6.10 of the respective decisions, the ACCC included pass-through rules in the revenue caps for TransGrid and EnergyAustralia.

15.6 The AER's considerations

Given that the code (now the National Electricity Rules) has not been amended at this time, the AER proposes to maintain consistency with the TransGrid and EnergyAustralia revenue caps (2004–05 to 2008–09) by including a pass-through mechanism in DJV's draft revenue cap decision. Appendix J sets out the pass-through mechanism to form part of DJV's revenue cap. In summary, the pass-through mechanism provides for the following pass-through events:

- change in taxes event
- insurance event
- service standards event
- terrorism event.

The pass-through mechanism is based on TransGrid and EnergyAustralia's revenue caps but has been adjusted to reflect the circumstances of Directlink. In particular, pass-through events have been limited to events that occur after the date of the final decision, and a materiality requirement has been further defined. Under the pass-through mechanism, DJV is required to pass through any reduction in costs arising from a pass-through event.

15.7 Conclusion

After accounting for the code requirements, the AER's conclusion is to include the pass-through mechanism set out in appendix K in the revenue cap to be set for DJV for the 2005–06 to 2014–15 regulatory period.

16 Total revenue

16.1 Introduction

This chapter explains the AER's calculation of DJV's maximum allowed revenue (MAR) to take effect from the date of conversion to 30 June 2015. The remainder of this chapter sets out:

- the code requirements (section 16.2)
- the components of the building block approach (section 16.3)
- the appropriate length of the regulatory control period (section 16.4)
- DJV's proposed MAR (section 16.5)
- the AER's assessment of the building block components (section 16.6)
- the AER's draft decision (section 16.7).

16.2 Code requirements

Chapter 6.2 of the code requires the AER to set a revenue cap with an incentive mechanism for non-contestable transmission network services. The AER's role as regulator of transmission revenues is limited to determining a transmission network service provider's (TNSP) MAR. As shown below, the MAR is calculated by adding (or deducting) a financial incentive related to service standard performance and any approved pass-through amounts to (or from) the allowed revenue (AR).

TNSPs must notify customers by 15 May of the transmission charges that are to apply for the following financial year, in accordance with part E of chapter 6 of the code. The annual revenue that a TNSP recovers through these charges must not exceed the MAR set by the AER. Any over- or underrecoveries must be offset against a TNSP's revenue in the following year.

DJV advised the AER that NEMMCO is consulting with various parties—including TransGrid, Powerlink, Country Energy and DJV—in relation to the allocation of Directlink's regulated revenue. NEMMCO is expected to confirm the location of the regional boundary after the release of this draft decision. The AER notes that TransGrid already acts as the coordinating TNSP in the New South Wales (NSW) region for the recovery of EnergyAustralia's transmission revenue. It understands that DJV will make a formal agreement with the relevant coordinating TNSP under the code to give effect to the recovery of Directlink's revenue.

16.3 The accrual building block approach

The building block formula is used to calculate the unsmoothed revenue for the regulatory period. The MAR is equivalent to the AR for the first year of the revenue cap:

AR = return on capital + return of capital + opex + tax

= (WACC x WDV) + D + opex + tax

where:

AR = the allowed revenue

WACC = the nominal vanilla weighted average cost of capital

WDV = the written-down (depreciated) value of the asset base

D = depreciation

opex = operating and maintenance expenditure

tax = the expected business income tax payable.

Each subsequent year's AR is calculated as follows:

AR_t = AR_{t-1} x (1 + ΔCPI) x (1 – X)

where:

AR = the allowed revenue

t = the time period/financial year

ΔCPI = the change in the consumer price index

X = the smoothing factor.

The following formula is used to calculate the MAR for each year. If a pass-through is approved, the amount approved will be included in the MAR.

MAR_t = (allowed revenue) ± (financial incentive) ± (pass-through)

$$= \left(AR_t\right) \pm \left(\frac{\left(AR_{t-2} + AR_{t-2}\right)}{2} \times S_{ct}\right) \pm \text{(pass-through)}$$

where:

MAR = the maximum allowed revenue

AR = the allowed revenue

S = the service standards factor

t = the time period/financial year

ct = the time period/calendar year.

16.4 Length of the regulatory control period

16.4.1 DJV's application

DJV proposed a regulatory control period that commences from the date on which the AER's final decision comes into effect to 30 June 2015 (approximately 10 years). It stated that a 10 year regulatory period is justified given:

- the high initial and ongoing efficiency of Directlink's opex
- the unlikelihood of unforeseen capital expenditure (capex)
- the substantial cost savings to DJV, NEM participants and the AER from deferring the regulatory reset process until 2015.

In addition, DJV argued that a regulatory period of 10 years provides certainty that encourages private sector investment and attracts new entrants to the NEM. It noted that transmission investments are very long term investments for which investors seek as much certainty as possible, especially for regulated investments where returns are designed to reflect lower levels of risk. DJV contended that the AER's acceptance (given appropriate conditions, such as those presented by Murraylink Transmission Company) of a regulatory control period around 10 years would offer a positive signal to investors that it is willing to provide a good level of certainty where possible.

16.4.2 Submissions

The Energy Users Association of Australia (EUAA) stated that there would be advantages in requiring Directlink to operate as a regulated interconnector with a similar five year regulatory period applied to other TNSPs.

TXU argued that DJV should be provided with a 10 year regulatory period where:

- the approach set in the Murraylink decision is followed and provides an asset value based on the alternative project that passes the regulatory test
- there is minimal scope for efficiency gains.

In response, DJV maintained its proposed 10 year regulatory period is appropriate. It stated that there are no advantages to the AER applying a five year regulatory period to Directlink simply because it would be the same as the regulatory control period for TNSPs.

16.4.3 The AER's considerations

Clause 6.2.4(b) of the code states that the AER, in applying the form of economic regulation specified in clause 6.2.4(a), is to set a revenue cap to apply to each TNSP for a period of no less than five years. In determining the appropriate length of the regulatory control period, the AER must trade off providing sufficient time for the business to have an incentive to make efficiency gains, and ensuring customers do not have to wait too long to benefit from those gains in the form of lower prices.

The AER notes the EUAA’s comment that a regulatory period of five years should be set for DJV, which is consistent with the ACCC’s previous revenue cap decisions. It also notes that the above issues raised by interested parties are similar to those raised in the ACCC’s Murraylink decision. On several occasions, the ACCC has approved a regulatory control period of 10 years:

- *The Central West and the Northern Territory gas access arrangements*. In the Central West decision, the ACCC approved a 10 year period on the basis that it was a Greenfield project. The 10 year period was used to facilitate growth and expand the market. In the Northern Territory decision, the assets pertaining to the gas project were leased, so the ACCC set the regulatory period to match the period of the lease, which expires in 2011.

- *The Murraylink decision*. The ACCC considered that the magnitude of the efficiency gains achieved over the period was likely to be low. There appeared to be little scope for future efficiency gains on capital cost, because the opening asset value for Murraylink was based on an alternative project and was substantially less than Murraylink’s actual construction costs. The ACCC also considered that the proposed regulatory asset value of Murraylink is the initial regulated asset base (RAB) of the Murraylink Transmission Company, unlike for other regulated TNSPs for which uncertainty surrounds their significant capital expenditure (capex) and/or opex programs at the time of their revenue resets.

In its Murraylink decision, the ACCC noted that it would consider extending the regulatory period when requested by a TNSP. The TNSP, however, must justify extending the regulatory period beyond five years and demonstrate that any such change would not disadvantage users of network services. The ACCC would then consider the application’s merits and address the issues associated with the length of the regulatory period, as part of its revenue cap decision. One factor it would consider is the expected size of future efficiency gains. The ACCC allowed a 10 year regulatory period in the Murraylink decision.

For this draft decision, the AER considers the views of the ACCC in its Murraylink decision are still appropriate. It also considers that DJV may have limited opportunity to substantially reduce its costs because there is no allowance for a capex program and the AER proposes to approve only an efficient opex. Given the limited scope for efficiency gains, the enhanced certainty for DJV and the regulatory cost savings, therefore, the AER considers that a regulatory control period of 10 years should be provided.

16.4.4 Conclusion

The AER considers that DJV’s request for a 10 year regulatory control period is justified. It notes that the regulatory period provided would be slightly less than 10 years, given the expected timing of the final decision.

16.5 DJV's proposed maximum allowed revenue

In its revised application (dated 22 September 2004), DJV proposed that the calculation of the revenue be determined for a 10 year regulatory period. Its proposed revenue was determined on the basis that its opening RAB is $135.7 million.[160] DJV requested nominal smoothed revenues of $16.5 million in 2005–06, increasing to $18.1 million in 2014–15. Table 16.1 summarises DJV's proposed revenues, both unsmoothed and smoothed.

Table 16.1 DJV's proposed allowed revenues ($ million, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Return on capital	12.4	12.4	12.4	12.3	12.3	12.2	12.2	12.1	12.0	11.9
Return of capital	0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.2
Operating expenses	3.3	3.4	3.5	3.6	3.6	4.0	4.0	3.9	4.0	4.1
Taxes payable	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5
Franking credits	–0.6	–0.6	–0.6	–0.6	–0.7	–0.7	–0.7	–0.7	–0.7	–0.7
Unsmoothed AR	16.5	16.7	16.9	17.0	17.2	17.6	17.7	17.6	17.8	17.9
Smoothed AR	16.5	16.7	16.9	17.0	17.2	17.4	17.6	17.7	17.9	18.1

16.6 The AER's assessment of the building blocks

16.6.1 Asset base roll-forward

The basic method underlying the roll-forward of DJV's asset base is that the closing value of the asset base from year to year is constructed by taking the opening value, converting it to a nominal figure by adding in an inflation adjustment, adding in any capital expenditure and subtracting disposals and depreciation for the year. The closing value for one year's asset base becomes the opening value for the following year's asset base.

As explained in chapter 11, the AER determined the depreciated value of DJV's opening asset base to be $116.68 million at 1 July 2005. The AER notes that the opening depreciated asset value does not require additional capex over the regulatory period of 10 years. Although DJV has committed to implementing equipment upgrades to improve the reliability of Directlink, this commitment is not included as a separate capex allowance. The estimated market benefits of Directlink are based on an assumed 99 per cent reliability level for the regulatory test assessment (section 7.4.2).

Based on the above components, the AER has modelled DJV's asset base over the regulatory period as shown in table 16.2.

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160 DJV amended its opening RAB to $138.7 million on 8 February 2005.

Table 16.2 The AER's forecast roll-forward asset value ($ million, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Opening asset value	116.7	116.8	116.9	116.7	116.5	116.3	115.9	115.4	114.8	114.1
Return of capital	–0.1)	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.8
Closing asset value	116.8	116.9	116.8	116.7	116.5	116.1	115.7	115.1	114.4	113.6

16.6.2 Depreciation (return of capital)

Using a post-tax nominal framework, the AER has made allowance for economic depreciation that adds together the (negative) straight-line depreciation with the (positive) annual inflation effect on the asset base. This economic depreciation has been used to model the nominal asset values over the regulatory period and to determine the depreciation allowance. In modelling the applicable straight-line depreciation component, the AER has based the calculation on the remaining life per asset class. Table 16.2 shows the resulting figures (referred to as return of capital).

16.6.3 Weigted average cost of capital

To establish the appropriate return on capital, the AER modelled DJV's RAB (over the length of the regulatory period) and multiplied it by the WACC (estimated on the basis of the most recent financial market information, as explained in chapter 13).

The AER has used a post-tax nominal return on equity of 11.50 per cent, combined with a pre-tax nominal cost of debt of 6.34 per cent, which equates to a nominal vanilla WACC of 8.40 per cent. This WACC is multiplied by the RAB to determine the return on capital component for 2005–06 to 2014–15, as shown in table 16.3. The AER will update the WACC with prevailing market bond rates for its final decision.

16.6.4 Operating and maintenance expenditure

As explained in chapter 12, the AER has included an opex allowance of around $2 million per year over the regulatory period. This equates to an average of $2.4 million in nominal terms, as shown in table 16.3.

16.6.5 Estimated taxes payable

Tax estimates relate to the network's regulated activities only. The AER anticipates DJV would pay income tax during the regulatory period, based on DJV's tax depreciation profile. Its assessment of taxes payable are based on the 60 per cent gearing assumed in the WACC framework, as opposed to DJV's actual gearing. Table 16.3 shows the AER's estimates of DJV's tax payments.

16.7 The AER's draft decision

Based on its assessment of the building block components, the AER has determined the appropriate AR for DJV. It proposes an unsmoothed revenue allowance that increases from $12.1 million in 2005–06 to $13.6 million in 2014–15, as shown in table 16.3.

Table 16.3 The AER's draft decision on unsmoothed allowed revenue ($ million, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Return on capital	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.7	9.7	9.6
Return of capital	–0.1	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.8
Operating expenses	2.0	2.1	2.2	2.2	2.3	2.6	2.6	2.5	2.5	2.6
Taxes payable	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.1
Franking credits	–0.4	–0.4	–0.4	–0.4	–0.5	–0.5	–0.5	–0.5	–0.5	–0.5
Unsmoothed AR	12.1	12.3	12.4	12.6	12.8	13.2	13.3	13.2	13.4	13.6

The AER has forecast a smoothed revenue allowance for DJV that increases from $12.1 million in 2005–06 to $13.7 million in 2014–15, as shown in table 16.4. The forecast applies a smoothing X factor of 1.36 per cent.

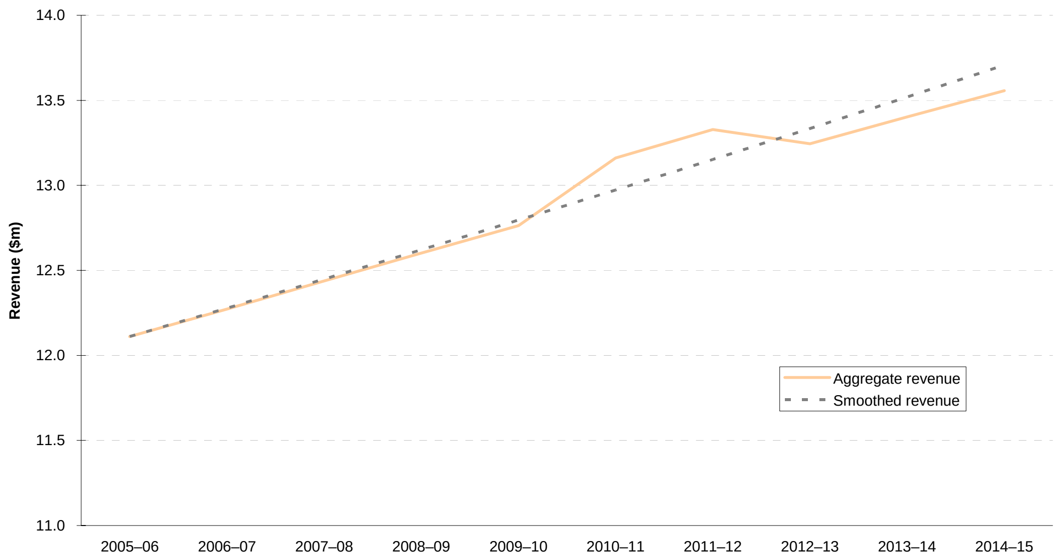
Table 16.4 The AER's draft decision on smoothed allowed revenue ($ million, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Smoothed AR	12.1	12.3	12.5	12.6	12.8	13.0	13.2	13.3	13.5	13.7

Because DJV's AR for the first year is calculated on a 2005–06 financial year and the conversion of Directlink will not occur until after 1 July 2005, the 2005–06 AR will need to be adjusted on a pro rata basis according to the actual date of conversion. This adjustment to the AR will be made to coincide with the date on which Directlink converts from a market network service to a prescribed service. For this draft decision, the 2005–06 AR has been pro rated to $8.1 million, to coincide with the date of 28 October 2005.

The subsequent year's MAR is determined by adjusting the previous year's forecast AR for actual inflation and the X factor, then adding to (or deducting from) the AR the service standards incentive (or penalty) and any allowed pass-through amounts (appendix K). Figure 16.1 provides the revenue path allowed in this draft decision (both smoothed and unsmoothed). The average revenue increase over the regulatory period is about 1.4 per cent per annum (nominal).

Figure 16.1 Revenue path 2005–06 to 2014–15 ($ million, nominal)



The smoothed revenue allowance of $12.1 million in 2005–06 to $13.7 million in 2014–15 that the AER has determined for the Directlink Joint Venturers is, on average, around 25 per cent less than the requested smoothed revenue allowance of $16.5 million in 2005–06 to $18.1 million in 2014–15.

The AER considers that it has been a difficult task to determine an appropriate asset value on which to base the maximum allowed revenue for DJV. It has had to exercise caution so as not to affect incentives for future investment. For the reasons discussed in chapter 11, the AER considers that the proposed revenue is appropriate and robust. The smoothed revenue allowance is consistent with the level of benefits that Directlink would provide to the market through its efficient operation.

The prescribed form and mechanism of regulation the AER has applied is also consistent with clauses 6.2.3 and 6.2.4 of the National Electricity Code (the code), in that it provides a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets. It also provides an acceptable balancing of the interests of TNSPs and users in line with the objectives of clause 6.2.2 of the code.

The AER notes, however, that the conversion of Directlink is an option for DJV and that DJV may choose to continue operating as a market network service.

Appendix A Review process

The following review process has occurred in consideration of the Directlink Joint Venturer's (DJV) application.

6 May 2004	DJV submitted its application for conversion. The ACCC called for interested parties to make submissions on the application.
4 June 2004	Submissions on the application closed. Five submissions were received and are available on the AER's website.[161]
16 July 2004	DJV advised the ACCC of its intention to submit additional information in light of Queensland network planning developments.
24 August 2004	DJV provided a submission that responded to issues that interested parties raised about its application.
30 August 2004	The ACCC requested that DJV submit a revised application to facilitate assessment by the ACCC, its consultants and interested parties.
22 September 2004	DJV submitted a revised application for conversion. The ACCC called for interested parties to make submissions on the revised application.
15 October 2004	Submissions on the revised application closed. One submission was received and is available on the AER's website.
3 November 2004	DJV submitted a paper proposing an alternative asset valuation method.
9 November 2004	DJV submitted a confidential proposed performance incentive scheme. On 17 November 2004, the ACCC received a public version of the proposed scheme, which was placed on the AER's website.
26 November 2004	The ACCC received PB Associates' report on DJV's application and the report was placed on the AER's website. Interested parties were asked to make submissions on PB Associates' report.
7 December 2004	The New South Wales (NSW) Department of Infrastructure, Planning and Natural Resources provided advice on undergrounding issues. The ACCC had sought advice on this matter in a letter dated 1 December 2004.
15 December 2004	DJV requested a time extension to comment on PB Associates' report. The ACCC granted this request.
16 December 2004	Submissions on PB Associates' report closed. Five submissions were received and are available on the AER's website.
14 January 2005	DJV submitted a response to PB Associates' report.
8 February 2005	DJV submitted a supplementary response to PB Associates' report with revised project cost estimates, network deferral benefits and regulatory test calculations.
March–April 2005	The ACCC received correspondence from various parties (DJV, Country Energy, TransGrid, PB Associates) in relation to the NSW north coast network development proposals. This is available on the AER's website.
26 April 2005	The ACCC received IES's report, which was placed on the AER's website.

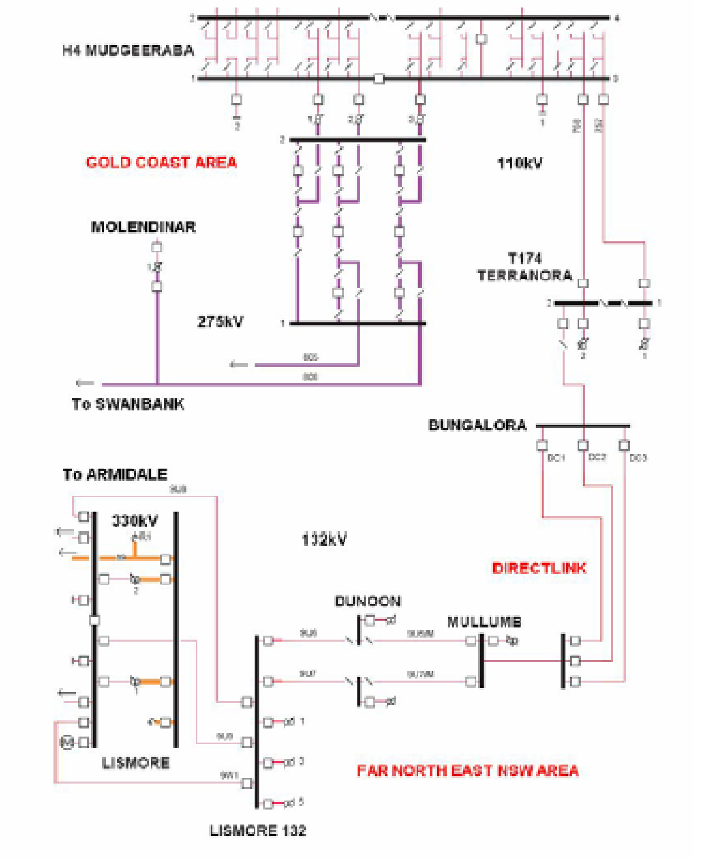
[161] <http://www.aer.gov.au>

	Interested parties were asked to make submissions on IES's report.
13 May 2005	DJV submitted a report on the costs of options to provide back-up supply to Tenterfield. This was in response to a request by the ACCC on 12 April 2005 for additional information on DJV's assessment of options.
16 May 2005	Submissions on IES's report closed. Four submissions were received and are available on the AER's website.
2 June 2005	The ACCC received additional interregional modelling base case results from IES.
15 June 2005	The ACCC received additional interregional modelling base case results from DJV.
22 June 2005	DJV corrected its additional modelling base case results of 15 June 2005.
July 2005	The AER received correspondence from various parties (DJV, Powerlink, TransGrid) in relation to southern Queensland network capability.
14 July 2005	The AER requested DJV provide additional interregional modelling results for scenarios that were flagged in April 2005 as part of the additional modelling.
27 July 2005	DJV provided a submission that responded to issues that interested parties raised about the AER consultants' reports.
9 September 2005	The AER received additional interregional modelling results from DJV for several scenarios.
14 September 2005	The AER received a letter from Metgasco regarding proposed embedded generation in northern NSW.
15 September 2005	The AER received a letter from Country Energy regarding correspondence between it and Powerlink concerning the timing of works at Powerlink's Molendinar substation and its implications for south flows across Directlink.
23 September 2005	DJV provided a compendium of additional interregional modelling results.
8 November 2005	The AER made its draft decision.

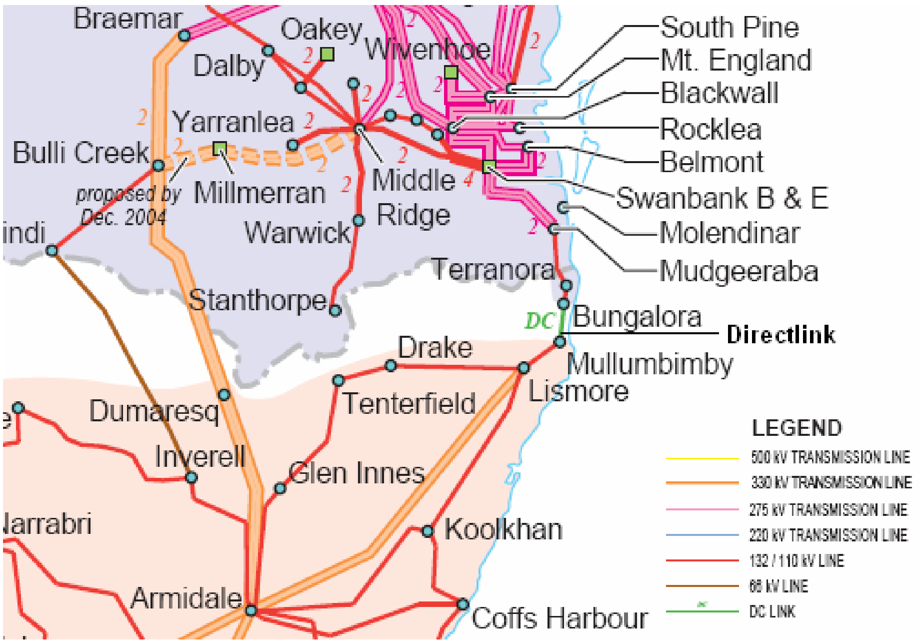
A copy of DJV's application, consultancy reports and submissions are available on the AER's website. The following interested parties provided submissions:

- NEMMCO
- TransGrid
- TXU
- Powerlink
- the Energy Users Association of Australia
- the Energy Retailers Association of Australia
- Sunshine Electricity
- Origin Energy
- Metgasco.

Appendix B Directlink system diagram and location



Source: BRW, *Directlink Joint Venture: Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*, 22 September 2004, p. 37.



Source: NEMMCO, *2004 Statement of Opportunities*, appendix E, 2004.

Appendix C The 1999 regulatory test

Preamble

The Australian Competition and Consumer Commission promulgates this *regulatory test* in accordance with clause 5.6.5(q)(1) of the National Electricity Code (the Code).

The *regulatory test* is to be applied:

(a) to *transmission system* or *distribution system* augmentation proposals in accordance with clause 5.6.2 of the Code (*augmentation*);

(b) by NEMMCO and the Inter-regional Planning Committee to augmentation options identified under clause 5.6.5 of the Code other than applications for new interconnectors in accordance with clause 5.6.6 of the Code (*augmentation option*); and

(c) by NEMMCO and the Inter-regional Planning Committee to applications for new interconnectors across regions in accordance with clause 5.6.5 and 5.6.6 of the Code (*new interconnectors*).

In this test, *augmentations*, *augmentation options* and *new interconnectors* are called *proposed augmentations*.

The *regulatory test*

The Commission has determined that the regulatory test is as follows:

A *new interconnector or an augmentation option* satisfies this test if it maximises the *net present value* of the *market benefit* having regard to a number of alternative projects, timings and market development scenarios; and

An augmentation satisfies this test if—

(a) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code—the *augmentation* minimises the net present value of the *cost* of meeting those standards; or

(b) in all other cases—the augmentation maximises the net present value of the *market benefit*

having regard to a number of alternative projects, timings and market development scenarios.

For the purposes of the test:

(a) *market benefit* means the total net benefits of the *proposed augmentation* to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios;

(b) *cost* means the total cost of the *augmentation* to all those who produce, distribute or consume electricity in the National Electricity Market. Any requirements in notes 1 to 9, inclusive, on the methodology to be used to calculate the *market benefit* of a *proposed augmentation* should also be read as a requirement on the methodology to be used to calculate the *cost* of an *augmentation*;

(c) the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector;

(d) the calculation of the *market benefit* or *cost* should encompass sensitivity analysis with respect to the key input variables, including capital and operating costs, the discount rate and the *commissioning* date, in order to demonstrate the robustness of the analysis;

(e) a *proposed augmentation* maximises the *market benefit* if it achieves a greater *market benefit* in most (although not all) credible scenarios; and

(f) an *augmentation* minimises the *cost* if it achieves a lower *cost* in most (although not all) credible scenarios.

Notes on the methodology to be used in the *regulatory test* to a proposed augmentation

(1) In determining the *market benefit*, the following information should be considered:

(a) the cost of the *proposed augmentation*;

(b) 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 value of energy to electricity consumers as reflected in the level of VoLL;

iii. 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;

iv. the capital costs of *committed*, *anticipated* and *modelled projects* including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;

v. the cost of providing sufficient ancillary services to meet the forecast demand; and

vi. the capital and operating costs of other regulated network and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.

(c) the proponent's nominated *construction timetable* must include a *start of construction*, *construction time* and *commissioning*, where:

i. *start of construction* means the date at which construction is required to commence in order to meet the *commissioning* date, taking into consideration the *construction time* nominated by the proponent;

ii. *construction time* is the time nominated by the proponent to order equipment and build the project and does not include the time required to obtain environmental, regulatory or planning approval; and

iii. *commissioning* means the date, nominated by the proponent, on which the project is to be placed into commercial operation.

(2) In determining the *market benefit,* 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 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*.

(3) The costs identified in determining the *market benefit* should include 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. 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. Any other costs should be disregarded.

(4) In determining the *market benefit,* any benefit or cost which cannot be measured as a benefit or cost 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 (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.

(5) In determining the *market benefit,* the analysis should include modelling a range of reasonable alternative 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. These scenarios should include projects undertaken to ensure that relevant reliability standards are met.

These market development scenarios should include:

(a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (*committed projects*);

(b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (*anticipated projects*);

(c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant (*modelled projects*); and

(d) any other projects identified during the consultation process.

(6) Modelled projects should be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.

(a) The least-cost market development approach includes modelled 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) The market-driven market development approach mimics market processes by 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 actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.

(7) In determining the *market benefit,* the *proposed augmentation* should not pre-empt nor distort potential unregulated developments including network, generation and demand side developments. To this end:

(a) a *proposed augmentation* must not be determined to satisfy this test more than 12 months before the *start of construction* date;

(b) a *proposed augmentation* will cease to satisfy this test if it has not commenced operation by 12 months after the *commissioning* date unless there has been a delay clearly due to unforeseen circumstances;

(c) unless there are exceptional circumstances, *new interconnectors* must not be determined to satisfy this test if *start of construction* is within 18 months of the project's need being first identified in a network's annual planning review or NEMMCO's statement of opportunities (or in some similar published document in the period prior to 13 December 1998).

(8) The consultation process for determining whether a *proposed augmentation* satisfies this test must be an open process, with interested parties having an opportunity to provide input and understand how the benefits have been measured and how the decision has been made. Specific consultation is required on:

(a) identifying *committed projects* and *anticipated projects*;

(b) setting input assumptions such as fuel costs and load growth;

(c) modelling market behaviour and considering whether the market development scenarios are realistic;

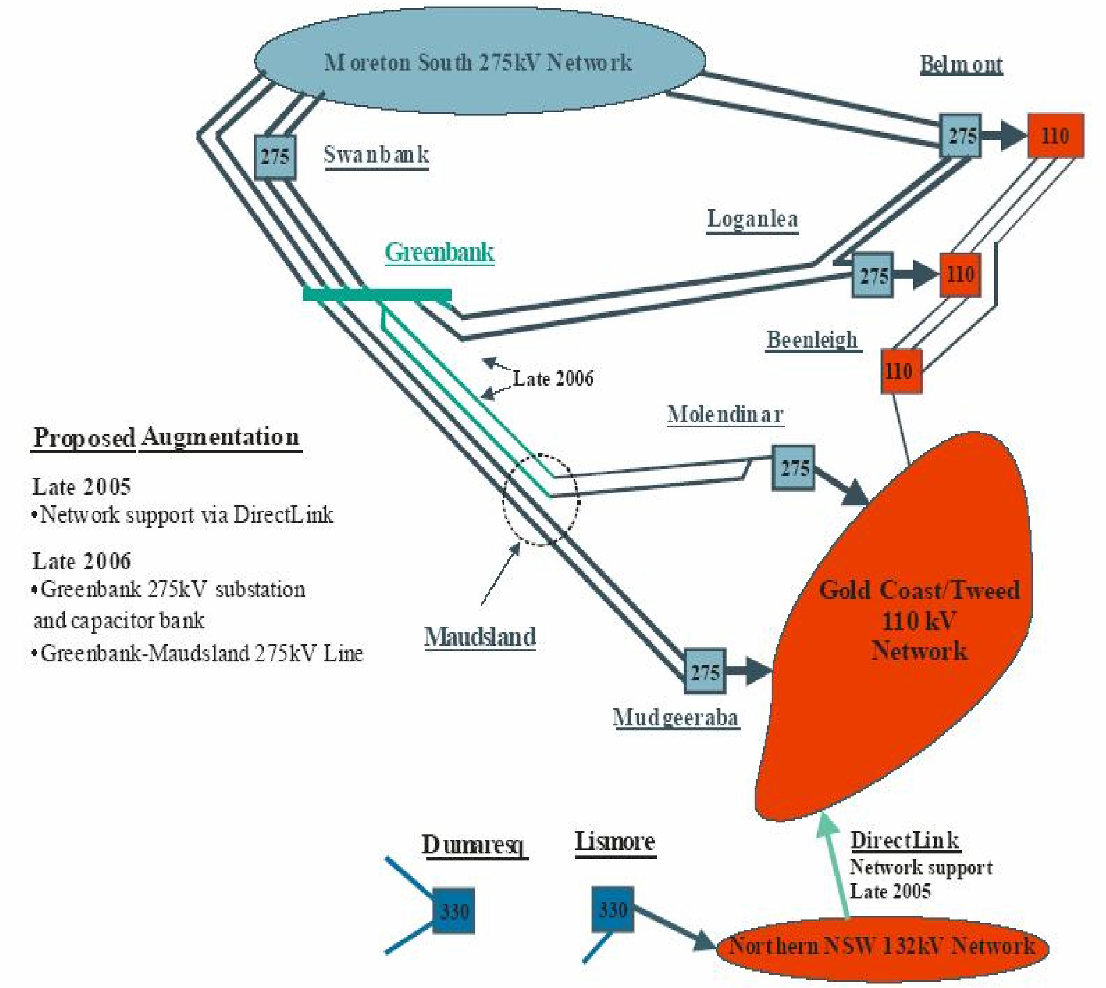
(d) the proponent's *construction timetable*;

(e) understanding how benefits will be allocated; and

(f) understanding how a decision has been made.

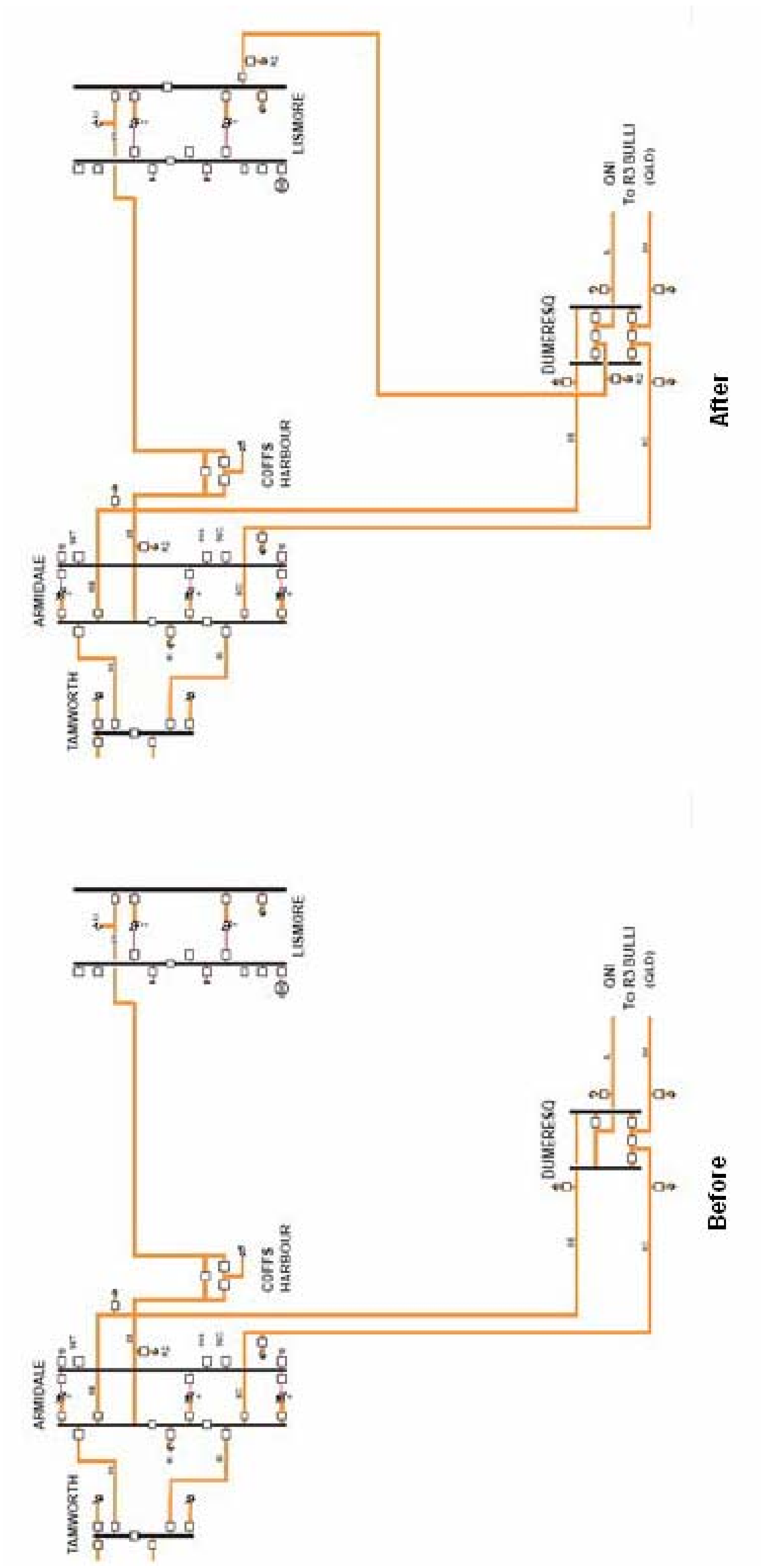
(9) Any information which may have a material impact on the determination of *market benefit* and which comes to light at any time before the final decision must be considered and made available to interested parties.

Appendix D Greenbank–Maudsland 275 kV augmentation system diagram



Source: Powerlink and Energex, *Proposed New Large Network Asset—Gold Coast and Tweed Areas Final Report*, Brisbane, July 2004, p. 37.

Appendix E Dumaresq–Lismore 330 kV augmentation system diagram



Source: BRW, *Directlink Joint Venture: Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*, 22 September 2004, p. 31.

Appendix F Directlink's alternative projects

This appendix sets out the AER's consideration of network augmentation deferral and interregional transfer benefits attributed to alternatives 1, 2 and 3. It considers:

- the network deferral and interregional benefits of alternatives 1 and 2 (section F.1)
- the network deferral benefits of alternative 3 (section F.2)
- the interregional benefits of alternative 3 (section F.3).

F.1 Alternatives 1 and 2

F.1.1 Network augmentation deferral benefits

DJV's application

The timing of augmentations in the 'with alternative 1 or 2' case is the same as that identified in the 'with Directlink' case.[162] Alternatives 1 and 2 are both direct current (DC) projects that deliver the same level of network support as Directlink delivers. The deferral benefits of Directlink and alternatives 1 and 2 are the same for each combination of load growth and discount rate because their deferral periods are the same. Consequently, BRW equated the network deferral benefits of alternatives 1 and 2 to those of Directlink.

The consultancy report

Parsons Brinckerhoff Associates (PB Associates) agreed that alternatives 1 and 2 provide the same deferral benefits as Directlink.[163]

The AER's considerations

The AER has considered the views of BRW and PB Associates. Chapter 7 sets out the AER's consideration of Directlink's network deferral benefits. It appears reasonable that alternatives 1 and 2 provide the same network deferral benefits as Directlink provides—see table F.1 (illustrated for one scenario).

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[162] BRW, *Directlink: Selection and Assessment of Alternative Projects*, op. cit., pp. 41–3.
[163] PB Associates, *Review of Directlink Conversion Application*, op. cit., p. 61.

Table F.1 The AER's conclusion on expected deferral benefit with alternative 1 or 2 ($ million, 1 July 2005)

	Present value of:		
	Costs under the reference case	Costs in the presence of alternative project	Deferral benefit
Greenbank augmentation	67.6	62.0	5.6
Dumaresq line	142.6	59.9	82.7
Tenterfield substation	12.6	5.3	7.3
Total	222.8	127.2	95.6

F.1.2 Interregional transfer benefits

DJV's application

As noted, alternatives 1 and 2 are both DC alternative projects that deliver the same level of technical network support as Directlink delivers. BRW proposed transfer limits for alternatives 1 and 2 that are the same as those for Directlink. Consequently, TransÉnergie US Limited's (TEUS) additional modelling estimated the same interregional benefits for alternatives 1 and 2 as for Directlink—see table F.2 (illustrated for two scenarios).

Table F.2 DJV's estimate of interregional benefits with alternative 1 or 2 ($ million, 1 July 2005)[(a)]

Unserved energy (USE) value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	2.18	23.46	–	14.79	40.43
$29 600/MWh	2.18	23.46	–	43.77	69.41

(a) Note that only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

The consultancy report

PB Associates reviewed alternatives 1 and 2 and agreed with BRW that the same transfer limits should apply as for Directlink. Intelligent Energy Systems (IES) agreed with TEUS that alternatives 1 and 2 provide the same interregional benefits as Directlink provides.

The AER's considerations

The AER has considered DJV's estimated interregional benefits for alternatives 1 and 2, and the advice of IES. Alternatives 1 and 2 provide the same interconnection capacity as Directlink provides, so it is reasonable that alternatives 1 and 2 provide the same interregional benefits as Directlink provides—see table F.3 (illustrated for two scenarios).

Table F.3 The AER’s conclusion on interregional benefits with alternative 1 or 2 ($ million, 1 July 2005)[(a)]

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	2.18	23.46	–	14.79	40.43
$29 600/MWh	2.18	23.46	–	43.77	69.41

(a) Note that only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

F.1.3 Conclusion

The AER considers that alternatives 1 and 2 offer the same level of technical support that Directlink offers. Consequently, these alternative projects provide the same network deferral and interregional benefits that have been estimated for Directlink.

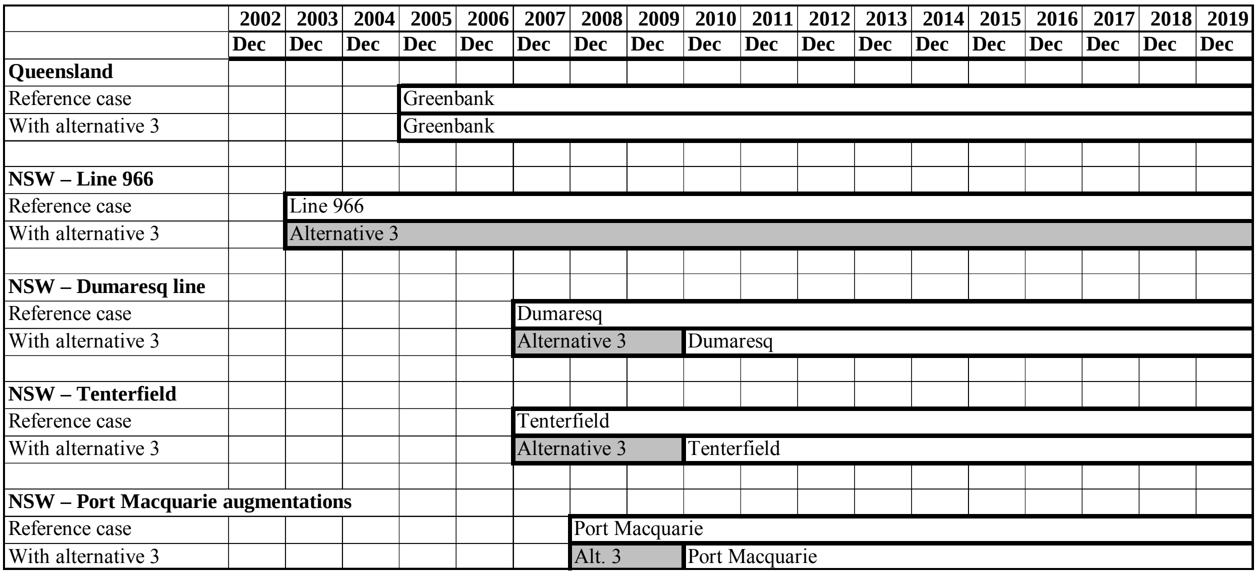
F.2 Alternative 3—network augmentation deferral benefits

F.2.1 Expected reliability augmentations

DJV’s application

DJV identified, in the ‘with alternative 3’ case, the altered timing of required augmentations—see table F.4. The impact of the revised timing on the expected augmentations with alternative 3 is illustrated in figure F.1.

Figure F.1 DJV’s view of expected deferral timing of the reference case with alternative 3 (medium growth)



DJV stated that alternative 3 offers less deferral benefit than Directlink offers, because it has limited ability to be dispatched in the opposite direction to the flows on the Queensland – New South Wales (NSW) Interconnector (QNI).[164] Alternative 3 is thus unable to defer the Queensland augmentations.

Table F.4 DJV's view of expected reliability failures and augmentations with alternative 3 (medium growth)

Loss of:	Date of contingency arising	Reliability failure	Required augmentations	Expected commissioning date
Queensland				
Line 805 or 806	2005–06 summer	Voltage stability limits exceeded within the Gold Coast network.	Greenbank augmentations	2005–06 summer
NSW				
Line 89	2010–11 summer	The Mudgeeraba–Terranora 110 kV line overloaded.	Dumaresq line	2010–11 summer
Glen Innes–Tenterfield line	2010–11 summer	The Tenterfield–Lismore line 132 kV line expected to be rebuilt during construction of the Dumaresq line. Without this line, Tenterfield serviced by only one line and Country Energy unable to meet its network reliability obligation to Tenterfield.	Tenterfield line or substation	2010–11 summer
Line 965 or line 96C and line 96G	2004 winter	Voltage regulation limits reached and customers exposed to low voltage conditions in the Coffs Harbour, Kempsey and Port Macquarie areas.	Port Macquarie augmentations	2010–11 summer

The consultancy report

PB Associates considered BRW's proposed timing of the augmentations in the presence of alternative 3 to be reasonable.[165] That is, alternative 3 can defer only the NSW augmentations in the reference case; it cannot defer the Queensland augmentations over 2005–06.

164 DJV, *Application for Conversion*, 22 September 2004, op. cit., p. 46.
165 PB Associates, *Review of Directlink Conversion Application*, op. cit., p. 58.

The AER's considerations

The AER has considered the views of BRW and PB Associates. It appears reasonable that alternative 3 has limited ability to be dispatched in the opposite direction to QNI and thus offers less deferral benefit than Directlink (or alternative 1 or 2) offers. The AER's considerations of the timing of the NSW augmentation deferrals with Directlink (or alternatives 1 and 2) apply equally in the 'with alternative 3' case:

- The ability to flow power south for the summer of 2006–07 remains uncertain. Powerlink stated that there is uncertainty about the impact of transformer capacity at Molendinar and constraints within Energex's network on the southern Gold Coast. While Powerlink recently confirmed its intention to bring forwards the installation of a second transformer at Molendinar for the summer of 2006–07, it is unclear whether it is possible to overcome limitations in Energex's network that would prevent both transformers being simultaneously energised.
- Given these uncertainties, it is reasonable for TransGrid to minimise the risk to its network by uprating line 966 to help alleviate its network reliability problems in the NSW north coast area. For this reason, no deferral of the uprating of line 966 is attributed to alternative 3.
- While there is some uncertainty about the capacity for power to flow south into the north coast of NSW during the summer of 2007–08, based on the available information the AER accepts that alternative 3 can defer construction of the Dumaresq–Lismore 330 kV line and the Tenterfield back-up supply from the summer of 2007–08.
- DJV has not provided sufficient evidence to support its proposition that alternative 3 can defer the Port Macquarie augmentations.
- Alternative 3 appears unlikely to provide any deferral benefits for the Port Macquarie augmentations.

Table F.5 summarises the AER's view of the altered timing in the 'with alternative 3' case for required augmentations to address contingency events and potential failures to meet reliability standards. The AER's view of the impact of the revised timing on the expected reference case augmentations is illustrated in figure F.2.

Table F.5 The AER's view of expected reliability failures and augmentations with alternative 3 (medium growth)

Loss of:	Date contingency arises	Reliability failure	Required augmentations	Expected commissioning date
Queensland				
Line 805 or 806	2005–06 summer	Voltage stability limits exceeded within the Gold Coast network.	Greenbank augmentations	2005–06 summer
NSW				
Line 89	2003–04 summer	Line 966 overloaded.	Line 966	2006–07 summer
Line 89	2010–11 summer	The Mudgeeraba–Terranora 110 kV line overloaded.	Dumaresq line	2010–11 summer
Glen Innes–Tenterfield line	2010–11 summer	The Tenterfield–Lismore line 132 kV line expected to be rebuilt during construction of the Dumaresq line. Without this line, Tenterfield serviced by only one line and Country Energy unable to meet its network reliability obligation to Tenterfield.	Tenterfield substation	2010–11 summer
Line 965 or line 96C and line 96G	2004 winter	Voltage regulation limits reached and customers exposed to low voltage conditions in the Coffs Harbour, Kempsey and Port Macquarie areas.	Port Macquarie augmentations	2008–09 summer

Figure F.2 The AER's view of expected deferral timing of the reference case with alternative 3 (medium growth)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec	Dec
Queensland																		
Reference case				Greenbank														
With alternative 3				Greenbank														
NSW – Line 966																		
Reference case					Line 966													
With alternative 3					Line 966													
NSW – Dumaresq line																		
Reference case						Dumaresq												
With alternative 3						Alternative 3			Dumaresq									
NSW – Tenterfield																		
Reference case						Tenterfield												
With alternative 3						Alternative 3			Tenterfield									
NSW – Port Macquarie augmentations																		
Reference case							Port Macquarie											
With alternative 3							Port Macquarie											

F.2.2 Economic benefits attributed to deferral of the reference case

DJV's application

BRW estimated the economic value of alternative 3's transmission network deferral benefits as $71.9 million (based on a 9 per cent discount rate and a medium growth forecast).

Submissions

The AER received no submissions on the calculation of the deferral benefits for alternative 3.

The AER's considerations

Based on its considerations in section F.2.1, the AER considers that the network deferral benefit for alternative 3 is $35.5 million (based on a 9 per cent discount rate and a medium growth forecast).

F.2.3 Conclusion

Based on its views of the timing of the required augmentations to address network reliability standards with alternative 3, the AER considers the economic value of the deferral of transmission network augmentations is as shown in table F.6 (illustrated for one scenario).

Table F.6 The AER's conclusion on the expected deferral benefit with alternative 3 ($ million, 1 July 2005)

	Present value of:		
	Costs under the reference case	Costs in the presence of alternative 3	Deferral benefit
Dumaresq line	142.6	110.0	32.6
Tenterfield substation	12.6	9.7	2.9
Total	155.2	119.7	35.5

F.3 Alternative 3—interregional transfer benefits

F.3.1 Transfer limits

DJV's application

Table F.7 summarises BRW's assessment of the transfer limits across the regions in the 'with alternative 3' case. BRW provided these peak transfer limits to TEUS for estimating the interregional benefits of alternative 3 from deferring reliability entry generation and reducing unserved energy (USE).

Transfers across alternative 3

BRW stated that the maximum active power flow for alternative 3 is 180 megawatts (MW). The maximum flow at any particular time, however, may be less and depends on the power flows on the QNI. As an alternating current (AC) transmission line, alternative 3 will generally flow in the same direction as the QNI. To achieve transfers in the opposing direction to the QNI, alternative 3 incorporates a phase shifting transformer. BRW assumed a limit on the phase angle that can be achieved using the phase shifting transformer, such that full transfer south can be achieved on alternative 3 while the QNI is at maximum transfer in a northerly direction. Full transfer north on alternative 3, however, requires simultaneous transfer north on the QNI.

Alternative 3 is not designed to alleviate the constraints in Queensland that require the Greenbank augmentation. Rather, it is designed to provide temporary relief for the constraints affecting northern NSW. BRW noted that transfer losses over alternative 3 are lower than for Directlink and alternatives 1 and 2, thereby increasing the transfer capacity in some instances. The transfer limits across alternative 3 will be dictated by the same constraints that apply to Directlink. For north flows, the constraints are:

- the continuous thermal rating of the double circuit 132 kV connection from Lismore to Mullumbimby, less the Mullumbimby and Dunoon load
- the three 132 kV lines supplying Lismore, less the combined Lismore, Mullumbimby and Dunoon load. Depending on the distribution of load growth in the region, any of the lines can be the limiting factor.

For south flows, the constraint is the continuous thermal rating of the double circuit 110 kV connection from Mudgeeraba to Terranora, less the Terranora load.

Table F.7 DJV's proposed transfer limits with alternative 3 (medium growth, MW)

Year	NSW to North NSW	North NSW to NSW	North NSW to Gold Coast (ALT 3)	Gold Coast to North NSW	North NSW to South QLD	South QLD to North NSW	South QLD to Gold Coast	Gold Coast to South Qld	South QLD to North QLD	North QLD to South QLD
2005–06	1200	950	139	91	300-ALT3	800	650-(0.75xALT3)	650	1750	1750
2006–07	1200	950	137	148	300-ALT3	800	850	850	1750	1750
2007–08	1200	950	134	148	300-ALT3	800	850	850	1750	1750
2008–09	1200	950	132	148	300-ALT3	800	1200	1200	1750	1750
2009–10	1200	950	129	148	300-ALT3	800	1200	1200	1750	1750
2010–11	1200	950	126	148	300-ALT3	800	1200	1200	1750	1750
2011–12	1200	950	123	148	300-ALT3	800	1200	1200	1750	1750
2012–13	1200	950	120	144	300-ALT3	800	1200	1200	1750	1750
2013–14	1200	950	118	141	300-ALT3	800	1200	1200	1750	1750
2014–15	1200	950	117	138	300-ALT3	800	1200	1200	1750	1750
2015–16	1200	950	115	135	300-ALT3	800	1200	1200	1750	1750
2016–17	1200	950	113	132	300-ALT3	800	1200	1200	1750	1750
2017–18	1200	950	111	129	300-ALT3	800	1200	1200	1750	1750
2018–19	1200	950	110	126	300-ALT3	800	1200	1200	1750	1750
2019–20	1200	950	108	123	300-ALT3	800	1200	1200	1750	1750

Transfers across the QNI

BRW stated that the maximum transfer for north flows is assumed to be a constant 300 MW, which comprises transfer on both the QNI and alternative 3. For flows south on the QNI, BRW stated that alternative 3, being an AC interconnection operating in parallel with the QNI, reduces the QNI transfer limit to 800 MW. For transfers across the QNI above 800 MW, the loading on the transformers for alternative 3 exceeds their continuous rating. The maximum total transfer capacity south on the QNI plus alternative 3 is marginally less than that in the reference case for the QNI alone (that is, 950 MW).

The consultancy report

PB Associates stated that BRW's proposed transfer limits for alternative 3 are reasonable.

The AER's considerations

Transfers across alternative 3

The AER has considered the views of BRW and PB Associates on the peak transfer capability of alternative 3. The transfer limit uncertainties identified in chapter 8, in relation to the power available to flow across Directlink, also apply to alternative 3. The southward flow transfer limits during the summers of 2005–06 and 2006–07 are likely to be less than that forecast by BRW. Nonetheless, the AER will adopt the transfer limits for the purpose of the interregional modelling. The impact on the estimated interregional benefits for the summers of 2005–06 and 2006–07 is unlikely to be material because there is no effect on the timing of market entry. Further, the modelling of interregional benefits is hourly across the entire year and includes hours outside of peak demand. From the summer of 2007–08, adopting the transfer limits proposed by BRW is also reasonable.

Transfers across the QNI

As with Directlink, the AER notes that power available to transfer to Queensland across both the QNI and alternative 3 is sourced from a common network that serves northern NSW from central NSW. This network may constrain the total transfer northwards. When this constraint applies, increased flow north across one interconnector must be offset by an equal reduction of power flow north across the other.

For northward power transfers on alternative 3, the network constraints limit the maximum total transfer on the QNI and alternative 3 to 300 MW, so any increase in transfer on the alternative link requires a 1:1 reduction in the QNI transfer. For southward power transfers on alternative 3, the transfer on the QNI must be limited to 800 MW when alternative 3 carries around 150 MW south, which adds to a total of 950 MW. Given that the southward power transfer capability of QNI alone is 950 MW, alternative 3 does not add to the total southward transfer capacity and thus is unlikely to provide any interregional benefits.

F.3.2 Interregional benefits modelling

DJV's application

TEUS's original interregional benefits modelling for alternative 3 used the same transfer limits as used for Directlink and the other alternative projects. BRW advised TEUS that alternative 3 effectively provides no increase in interregional transfer capability. TEUS re-estimated the benefits of alternative 3 using this assumption, resulting in the energy and deferred market entry benefits being zero. In some scenarios, alternative 3 still provides a small positive reliability benefit; in others, the reliability benefits are slightly negative. Averaged over the scenarios, the reliability benefits are close to zero.[166]

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[166] TEUS, *Response to IES questions of 25 October 2004*, 18 January 2005, pp. 5–6.

Submissions and the consultancy report

IES noted that that TEUS's original PROSYM modelling for alternative 3 used the same transfer limits as used for Directlink because alternative 3 had the same market entry deferral. As discussed in section 8.3, TEUS agreed to undertake additional modelling with revised assumptions to address the concerns raised by IES. Its additional modelling estimated the value of each category of interregional benefits in the 'with alternative 3' case—see table F.8 (illustrated for two scenarios).

Table F.8 DJV's estimate of interregional benefits with alternative 3 ($ million, 1 July 2005)[a]

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	–	–	–	(2.61)	(2.61)
$29 600/MWh	–	–	–	(7.73)	(7.73)

(a) Note that only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

TEUS stated that the slightly lower transfer limits used for south flows in the 'with alternative 3' case have a slight negative impact on reliability, as shown in the results. In the market modelling of the 'without alternative 3'case, more capacity is added in Queensland than in NSW. Small reductions in the ability of this capacity to flow south can thus cause slightly more USE in the 'with alternative 3' case.

IES noted that alternative 3 does not provide any increase in the interregional transfer capacity between NSW and Queensland, so would not be expected to provide any interregional benefits. It agreed with TEUS's additional modelling results which showed that the total benefits would be negligible.

The AER's considerations

TEUS appears to have not used the correct transfer limits for alternative 3 for the original interregional benefits, modelling the service level on the same basis as Directlink. TEUS re-estimated the benefits of alternative 3 by recognising that there is no increase in interregional transfer capacity. Some of IES's concerns (section 8.3.2) remain, however.

The AER considers that TEUS's additional modelling for alternative 3 reasonably addresses IES's concerns. That is, the modelling is based on the revised assumptions of:

- generators bidding in the NEM at prices to reflect historically observed prices
- existing and committed generation, including that indicated by NEMMCO's 2004 *Statement of Opportunities*
- the updated new generation entry cost indicated in the *Report on NEM Generator Costs (Part 2)* by ACIL Tasman in February 2005.

F.3.3 Conclusion

The AER will adopt the interregional benefits estimated by TEUS in the additional modelling—see table F.9 (illustrated for two scenarios).

Table F.9 The AER's conclusion on interregional benefits with alternative 3 ($ million, 1 July 2005)[(a)]

USE value	Energy	Deferred market entry	Deferred reliability entry	Residual reliability	Total benefit
$10 000/MWh	–	–	–	(2.61)	(2.61)
$29 600/MWh	–	–	–	(7.73)	(7.73)

(a) Note that only two scenarios are displayed for illustrative purposes. Additional scenarios are displayed in appendix G.

Appendix G Tables referred to in chapter 10

Table G.1 DJV's proposed timing of augmentations for various growth rates

Required augmentations	Commissioning date under the reference case	Alternative project	Deferral period—demand growth forecast		
			Low	Medium	High
Queensland					
Greenbank augmentations	2005–06 summer	Directlink and alternative 1/2	2006–07 1 year	2006–07 1 year	2006–07 1 year
		Alternative 3	2005–06 0 years	2005–06 0 years	2005–06 0 years
New South Wales					
Uprating of line 966	2003–04 summer	Directlink and alternative 1/2	Permanent deferral	Permanent deferral	Permanent deferral
		Alternative 3	Permanent deferral	Permanent deferral	Permanent deferral
Dumaresq line	Low–medium growth: 2007–08 summer	Directlink and alternative 1/2	2019–20 12 years	2017–18 10 years	2015–16 9 years
	High growth: 2006–07 summer	Alternative 3	2010–11 3 years	2010–11 3 years	2009–10 3 years
Tenterfield line or substation	Low–medium growth: 2007–08 summer	Directlink and alternative 1/2	2019–20 12 years	2017–18 10 years	2015–16 9 years
	High growth: 2006–07 summer	Alternative 3	2010–11 3 years	2010–11 3 years	2009–10 3 years
Port Macquarie augmentations	Low growth: 2010–11 summer	Directlink and alternative 1/2	2012–13 2 years	2010–11 2 years	2010–11 2 years
	Medium–high growth: 2008–09 summer	Alternative 3	2012–13 2 years	2010–11 2 years	2010–11 2 years

Table G.2 DJV's estimated network deferral benefits for various discount rates and growth rates ($ million, 1 July 2005)

	Demand growth forecast		
Discount rate	**Low**	**Medium**	**High**
11 per cent			
Directlink	156.2	149.2	153.9
Alternative 1	156.2	149.2	153.9
Alternative 2	156.2	149.2	153.9
Alternative 3	76.2	80.2	85.0
9 per cent			
Directlink	146.0	137.5	139.3
Alternative 1	146.0	137.5	139.3
Alternative 2	146.0	137.5	139.3
Alternative 3	68.9	71.9	75.4
7 per cent			
Directlink	132.4	122.9	122.2
Alternative 1	132.4	122.9	122.2
Alternative 2	132.4	122.9	122.2
Alternative 3	60.6	62.7	65.0

Table G.3 DJV's estimated interregional benefits using an historical bidding strategy for various discount rates, growth rates, USE values and market entry costs ($ million, 1 July 2005)[a]

	Demand growth forecast and market entry cost									
	Low growth, market entry 100%		Medium growth, market entry 100%		High growth, market entry 100%		Medium growth, market entry 110%		Medium growth, market entry 90%	
Discount rate	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE
11 per cent										
Directlink	21.0	24.6	36.8	57.9	94.0	82.3	11.4	57.6	35.1	32.1
Alternative 1	21.0	24.6	36.8	57.9	94.0	82.3	11.4	57.6	35.1	32.1
Alternative 2	21.0	24.6	36.8	57.9	94.0	82.3	11.4	57.6	35.1	32.1
Alternative 3	na	na	(1.9)	(5.6)	na	na	na	na	na	na
9 per cent										
Directlink	22.8	25.7	40.4	69.4	174.1	156.8	15.9	75.6	79.9	76.8
Alternative 1	22.8	25.7	40.4	69.4	174.1	156.8	15.9	75.6	79.9	76.8
Alternative 2	22.8	25.7	40.4	69.4	174.1	156.8	15.9	75.6	79.9	76.8
Alternative 3	na	na	(2.6)	(7.7)	na	na	na	na	na	na
7 per cent										
Directlink	23.8	25.2	46.4	87.1	301.5	275.5	23.3	102.5	156.0	153.0
Alternative 1	23.8	25.2	46.4	87.1	301.5	275.5	23.3	102.5	156.0	153.0
Alternative 2	23.8	25.2	46.4	87.1	301.5	275.5	23.3	102.5	156.0	153.0
Alternative 3	na	na	(3.7)	(11.0)	na	na	na	na	na	na

(a) These results were provided in July 2005 as additional modelling undertaken by TEUS and based on revised assumptions.

na Not available.

Table G.4 DJV's estimated interregional benefits using a short run marginal cost (SRMC) bidding strategy and medium growth, by discount rate and USE value ($ million, 1 July 2005)[a]

	Discount rate					
	7 per cent		9 per cent		11 per cent	
	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE
Directlink	40.4	44.2	44.0	45.9	42.2	43.0
Alternative 1	40.4	44.2	44.0	45.9	42.2	43.0
Alternative 2	40.4	44.2	44.0	45.9	42.2	43.0
Alternative 3	(1.7)	2.6	(0.1)	4.1	1.1	5.3

(a) The results for Directlink and alternatives 1 and 2 were provided in July 2005 as part of the additional modelling undertaken by TEUS and based on revised assumptions. Alternative 3 results were provided in January 2005 and based on revised transfer limits.

Table G.5 DJV's estimated interregional benefits using a long run marginal cost (LRMC) bidding strategy and medium growth, by discount rate and USE value ($ million, 1 July 2005)[a]

	Discount rate					
	7 per cent		9 per cent		11 per cent	
	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE	$10 000 USE	$29 600 USE
Directlink	128.0	146.1	101.9	116.7	84.1	96.6
Alternative 1	128.0	146.1	101.9	116.7	84.1	96.6
Alternative 2	128.0	146.1	101.9	116.7	84.1	96.6
Alternative 3	(1.1)	7.1	0.2	7.8	1.2	8.3

(a) The results for Directlink and alternatives 1 and 2 were provided in January 2005 and based on revised network topology that modelled northern NSW separately. Alternative 3 results were provided in January 2005 and based on revised transfer limits.

Table G.6 DJV's estimated costs of Directlink and its alternative projects, by discount rate ($ million, 1 July 2005)

Discount rate	Capital cost	Directlink	Alternative 1	Alternative 2	Alternative 3
11 per cent	Project cost	172.2	244.0	146.6	68.3
	IDC	0	16.1	12.6	8.2
	Lifecycle opex[a]	26.2	26.2	26.2	24.4
	Total	198.4	286.3	185.4	100.9
9 per cent	Project cost	172.2	244.0	146.6	68.3
	IDC	0	13.1	10.2	6.6
	Lifecycle opex[a]	31.4	31.4	31.4	29.3
	Total	203.6	288.6	188.2	104.2
7 per cent	Project cost	172.2	244.0	146.6	68.3
	IDC	0	10.2	7.9	5.1
	Lifecycle opex[a]	38.9	38.9	38.9	36.2
	Total	211.1	293.1	193.4	109.6

(a) The lifecycle opex amount has been calculated as the present value of the annual opex over the assumed life of the assets.

IDC = interest during construction; opex = operating and maintenance expenditure.

Table G.7 DJV's estimated costs of augmentations, by discount rate ($ million, 1 July 2005)

Discount rate	Capital cost	Greenbank augmentation	Dumaresq line	Line 966	Tenterfield back-up	Port Macquarie augmentations
11 per cent	Project cost	50.8	148.0	11.3	14.0–14.6	127.3
	IDC	2.9	12.4	0.7	1.7–1.8	11.6
	Lifecycle opex[(a)]	14.1	14.7	na	na[(b)]	14.1
	Total	67.8	175.1	12.0	15.8–16.3	152.9
9 per cent	Project cost	50.8	148.0	11.3	14.0–14.6	127.3
	IDC	2.4	10.1	0.5	1.4–1.5	9.4
	Lifecycle opex[(a)]	16.9	17.7	na	na[(b)]	16.9
	Total	70.1	175.8	11.9	15.5-16.0	153.6
7 per cent	Project cost	50.8	148.0	11.3	14.0–14.6	127.3
	IDC	1.9	7.9	0.4	1.1–1.2	7.3
	Lifecycle opex[(a)]	20.9	21.8	na	na[(b)]	20.9
	Total	73.6	177.7	11.8	15.2–15.7	155.5

(a) The lifecycle opex amount has been calculated as the present value of the annual opex over the assumed life of the assets.

(b) BRW assumed the opex for the Tenterfield back-up options is incorporated in the opex estimate for the Dumaresq–Lismore line.

na Not applicable.

IDC = interest during construction; opex = operating and maintenance expenditure.

Table G.8 The AER's view of timing of augmentations for various growth rates

Required augmentations	Commissioning date under the reference case	Alternative projects	Deferral period—demand growth forecast		
			Low	**Medium**	**High**
Queensland					
Greenbank augmentations	2005–06 summer	Directlink and alternative 1/2	2006–07 1 year	2006–07 1 year	2006–07 1 year
		Alternative 3	2005–06 0 years	2005–06 0 years	2005–06 0 years
New South Wales					
Uprating of line 966	2006–07 summer	Directlink and alternative 1/2/3	2006–07 0 years	2006–07 0 years	2006–07 0 years
Dumaresq line	2007–08 summer	Directlink and alternative 1/2	2019–20 12 years	2017–18 10 years	2015–16 8 years
		Alternative 3	2010–11 3 years	2010–11 3 years	2009–10 2 years
Tenterfield substation	2007–08 summer	Directlink and alternative 1/2	2019–20 12 years	2017–18 10 years	2015–16 8 years
		Alternative 3	2010–11 3 years	2010–11 3 years	2009–10 2 years
Port Macquarie augmentations	Low growth: 2010–11 summer Medium–high growth: 2008–09 summer	Directlink and alternative 1/2	2010–11 0 years	2008–09 0 years	2008–09 0 years
		Alternative 3	2010–11 0 years	2008–09 0 years	2008–09 0 years

Table G.9 The AER's conclusion on the costs of augmentations, by discount rate ($ million, 1 July 2005)

Discount rate	Capital cost	Greenbank augmentation	Dumaresq line	Line 966	Tenterfield substation	Port Macquarie augmentations
11 per cent	Project cost	50.8	148.0	11.3	14.0	127.3
	IDC	2.9	12.4	0.7	1.8	11.6
	Lifecycle opex(a)	14.1	14.7	na	na(b)	14.1
	Total	67.8	175.1	12.0	15.8	152.9
9 per cent	Project cost	50.8	148.0	11.3	14.0	127.3
	IDC	2.4	10.1	0.5	1.5	9.4
	Lifecycle opex(a)	16.9	17.7	na	na(b)	16.9
	Total	70.1	175.8	11.9	15.5	153.6
7 per cent	Project cost	50.8	148.0	11.3	14.0	127.3
	IDC	1.9	7.9	0.4	1.2	7.3
	Lifecycle opex(a)	20.9	21.8	na	na(b)	20.9
	Total	73.6	177.7	11.8	15.2	155.5

(a) The lifecycle opex amount has been calculated as the present value of the annual opex over the assumed life of the assets.

(b) BRW assumed the opex for the Tenterfield back-up options is incorporated in the opex estimate for the Dumaresq–Lismore line.

na Not applicable.

IDC = interest during construction; opex = operating and maintenance expenditure.

Table G.10 The AER's conclusion on network deferral benefits ($ million, 1 July 2005)

No.	Network deferral benefit scenario	USE value	Bidding strategy	Discount rate	Demand growth	Alternative project costs	Directlink network deferral	Alternative 1 network deferral	Alternative 2 network deferral	Alternative 3 network deferral
1	Sensitivity	29.6k	Historical	11%	High	100%	90.5	90.5	90.5	28.0
2	Sensitivity	29.6k	Historical	11%	Medium	100%	102.7	102.7	102.7	39.9
3	Sensitivity	29.6k	Historical	11%	Low	100%	112.5	112.5	112.5	39.9
4	Credible	29.6k	Historical	9%	High	100%	83.3	83.3	83.3	24.7
5	Credible	29.6k	Historical	9%	Medium	100%	95.6	95.6	95.6	35.5
6	Credible	29.6k	Historical	9%	Low	100%	106.1	106.1	106.1	35.5
7	Sensitivity	29.6k	Historical	7%	High	100%	73.9	73.9	73.9	20.9
8	Sensitivity	29.6k	Historical	7%	Medium	100%	86.0	86.0	86.0	30.4
9	Sensitivity	29.6k	Historical	7%	Low	100%	96.7	96.7	96.7	30.4
10	Sensitivity	29.6k	SRMC	11%	Medium	100%	102.7	102.7	102.7	39.9
11	Sensitivity	29.6k	SRMC	9%	Medium	100%	95.6	95.6	95.6	35.5
12	Sensitivity	29.6k	SRMC	7%	Medium	100%	86.0	86.0	86.0	30.4
13	Sensitivity	29.6k	LRMC	11%	Medium	100%	102.7	102.7	102.7	39.9
14	Sensitivity	29.6k	LRMC	9%	Medium	100%	95.6	95.6	95.6	35.5
15	Sensitivity	29.6k	LRMC	7%	Medium	100%	86.0	86.0	86.0	30.4
16	Sensitivity	10k	Historical	11%	High	100%	90.5	90.5	90.5	28.0
17	Sensitivity	10k	Historical	11%	Medium	100%	102.7	102.7	102.7	39.9
18	Sensitivity	10k	Historical	11%	Low	100%	112.5	112.5	112.5	39.9
19	Credible	10k	Historical	9%	High	100%	83.3	83.3	83.3	24.7
20	Credible	10k	Historical	9%	Medium	100%	95.6	95.6	95.6	35.5
21	Credible	10k	Historical	9%	Low	100%	106.1	106.1	106.1	35.5
22	Sensitivity	10k	Historical	7%	High	100%	73.9	73.9	73.9	20.9
23	Sensitivity	10k	Historical	7%	Medium	100%	86.0	86.0	86.0	30.4
24	Sensitivity	10k	Historical	7%	Low	100%	96.7	96.7	96.7	30.4
25	Sensitivity	10k	SRMC	11%	Medium	100%	102.7	102.7	102.7	39.9
26	Sensitivity	10k	SRMC	9%	Medium	100%	95.6	95.6	95.6	35.5
27	Sensitivity	10k	SRMC	7%	Medium	100%	86.0	86.0	86.0	30.4
28	Sensitivity	10k	LRMC	11%	Medium	100%	102.7	102.7	102.7	39.9
29	Sensitivity	10k	LRMC	9%	Medium	100%	95.6	95.6	95.6	35.5
30	Sensitivity	10k	LRMC	7%	Medium	100%	86.0	86.0	86.0	30.4
31	Sensitivity: local generation	10k	Historical	9%	Medium	100%	75.1	75.1	75.1	0.0
32	Sensitivity: local generation	29.6k	Historical	9%	Medium	100%	75.1	75.1	75.1	0.0
33	Sensitivity	29.6k	Historical	9%	Medium	110%	105.2	105.2	105.2	39.0
34	Sensitivity	29.6k	Historical	9%	Medium	90%	86.1	86.1	86.1	31.9
35	Sensitivity	10k	Historical	9%	Medium	110%	105.2	105.2	105.2	39.0
36	Sensitivity	10k	Historical	9%	Medium	90%	86.1	86.1	86.1	31.9
37	Sensitivity: +10%ME cost	10k	Historical	9%	Medium	100%	95.6	95.6	95.6	35.5
38	Sensitivity: –10%ME cost	10k	Historical	9%	Medium	100%	95.6	95.6	95.6	35.5
39	Sensitivity: +10%ME cost	29.6k	Historical	9%	Medium	100%	95.6	95.6	95.6	35.5
40	Sensitivity: –10%ME cost	29.6k	Historical	9%	Medium	100%	95.6	95.6	95.6	35.5
	Median for credible scenarios						95.6	95.6	95.6	35.5
	Median for sensitivities						95.6	95.6	95.6	35.5
	Median overall						95.6	95.6	95.6	35.5

Table G.11 The AER's conclusion on interregional benefits ($ million, 1 July 2005)

No.	Interregional benefit scenario	USE value	Bidding strategy	Discount rate	Demand growth	Alternative project costs	Directlink Interregional	Alternative 1 interregional	Alternative 2 interregional	Alternative 3 interregional
1	Sensitivity	29.6k	Historical	11%	High	100%	82.3	82.3	82.3	na
2	Sensitivity	29.6k	Historical	11%	Medium	100%	57.9	57.9	57.9	-5.6
3	Sensitivity	29.6k	Historical	11%	Low	100%	24.6	24.6	24.6	na
4	Credible	29.6k	Historical	9%	High	100%	156.8	156.8	156.8	na
5	Credible	29.6k	Historical	9%	Medium	100%	69.4	69.4	69.4	-7.7
6	Credible	29.6k	Historical	9%	Low	100%	25.7	25.7	25.7	na
7	Sensitivity	29.6k	Historical	7%	High	100%	275.5	275.5	275.5	na
8	Sensitivity	29.6k	Historical	7%	Medium	100%	87.1	87.1	87.1	-11.0
9	Sensitivity	29.6k	Historical	7%	Low	100%	25.2	25.2	25.2	na
10	Sensitivity	29.6k	SRMC	11%	Medium	100%	43.0	43.0	43.0	5.3
11	Sensitivity	29.6k	SRMC	9%	Medium	100%	45.9	45.9	45.9	4.1
12	Sensitivity	29.6k	SRMC	7%	Medium	100%	44.2	44.2	44.2	2.6
13	Sensitivity	29.6k	LRMC	11%	Medium	100%	96.6	96.6	96.6	8.3
14	Sensitivity	29.6k	LRMC	9%	Medium	100%	116.7	116.7	116.7	7.8
15	Sensitivity	29.6k	LRMC	7%	Medium	100%	146.1	146.1	146.1	7.1
16	Sensitivity	10k	Historical	11%	High	100%	94.0	94.0	94.0	na
17	Sensitivity	10k	Historical	11%	Medium	100%	36.8	36.8	36.8	-1.9
18	Sensitivity	10k	Historical	11%	Low	100%	21.0	21.0	21.0	na
19	Credible	10k	Historical	9%	High	100%	174.1	174.1	174.1	na
20	Credible	10k	Historical	9%	Medium	100%	40.4	40.4	40.4	-2.6
21	Credible	10k	Historical	9%	Low	100%	22.8	22.8	22.8	na
22	Sensitivity	10k	Historical	7%	High	100%	301.5	301.5	301.5	na
23	Sensitivity	10k	Historical	7%	Medium	100%	46.4	46.4	46.4	-3.7
24	Sensitivity	10k	Historical	7%	Low	100%	23.8	23.8	23.8	na
25	Sensitivity	10k	SRMC	11%	Medium	100%	42.2	42.2	42.2	1.1
26	Sensitivity	10k	SRMC	9%	Medium	100%	44.0	44.0	44.0	-0.1
27	Sensitivity	10k	SRMC	7%	Medium	100%	40.4	40.4	40.4	-1.7
28	Sensitivity	10k	LRMC	11%	Medium	100%	84.1	84.1	84.1	1.2
29	Sensitivity	10k	LRMC	9%	Medium	100%	101.9	101.9	101.9	0.2
30	Sensitivity	10k	LRMC	7%	Medium	100%	128.0	128.0	128.0	-1.1
31	Sensitivity: local generation	10k	Historical	9%	Medium	100%	40.4	40.4	40.4	-2.6
32	Sensitivity: local generation	29.6k	Historical	9%	Medium	100%	69.4	69.4	69.4	-7.7
33	Sensitivity	29.6k	Historical	9%	Medium	110%	69.4	69.4	69.4	-7.7
34	Sensitivity	29.6k	Historical	9%	Medium	90%	69.4	69.4	69.4	-7.7
35	Sensitivity	10k	Historical	9%	Medium	110%	40.4	40.4	40.4	-2.6
36	Sensitivity	10k	Historical	9%	Medium	90%	40.4	40.4	40.4	-2.6
37	Sensitivity: +10%ME cost	10k	Historical	9%	Medium	100%	15.9	15.9	15.9	na
38	Sensitivity: –10%ME cost	10k	Historical	9%	Medium	100%	79.9	79.9	79.9	na
39	Sensitivity: +10%ME cost	29.6k	Historical	9%	Medium	100%	75.6	75.6	75.6	na
40	Sensitivity: –10%ME cost	29.6k	Historical	9%	Medium	100%	76.8	76.8	76.8	na
	Median for credible scenarios						54.9	54.9	54.9	-5.2
	Median for sensitivities						63.7	63.7	63.7	-1.4
	Median overall						63.7	63.7	63.7	-1.8

Table G.12 The AER's conclusion on gross market benefits ($ million, 1 July 2005)

No.	Gross market benefit (GMB) scenario	USE value	Bidding strategy	Discount rate	Demand growth	Alternative project costs	Directlink GMB	Alternative 1 GMB	Alternative 2 GMB	Alternative 3 GMB
1	Sensitivity	29.6k	Historical	11%	High	100%	172.9	172.9	172.9	28.0
2	Sensitivity	29.6k	Historical	11%	Medium	100%	160.6	160.6	160.6	34.4
3	Sensitivity	29.6k	Historical	11%	Low	100%	137.1	137.1	137.1	39.9
4	Credible	29.6k	Historical	9%	High	100%	240.0	240.0	240.0	24.7
5	Credible	29.6k	Historical	9%	Medium	100%	165.0	165.0	165.0	27.8
6	Credible	29.6k	Historical	9%	Low	100%	131.8	131.8	131.8	35.5
7	Sensitivity	29.6k	Historical	7%	High	100%	349.4	349.4	349.4	20.9
8	Sensitivity	29.6k	Historical	7%	Medium	100%	173.2	173.2	173.2	19.4
9	Sensitivity	29.6k	Historical	7%	Low	100%	121.9	121.9	121.9	30.4
10	Sensitivity	29.6k	SRMC	11%	Medium	100%	145.7	145.7	145.7	45.2
11	Sensitivity	29.6k	SRMC	9%	Medium	100%	141.5	141.5	141.5	39.6
12	Sensitivity	29.6k	SRMC	7%	Medium	100%	130.3	130.3	130.3	32.9
13	Sensitivity	29.6k	LRMC	11%	Medium	100%	199.2	199.2	199.2	48.2
14	Sensitivity	29.6k	LRMC	9%	Medium	100%	212.3	212.3	212.3	43.3
15	Sensitivity	29.6k	LRMC	7%	Medium	100%	232.1	232.1	232.1	37.4
16	Sensitivity	10k	Historical	11%	High	100%	184.6	184.6	184.6	28.0
17	Sensitivity	10k	Historical	11%	Medium	100%	139.4	139.4	139.4	38.0
18	Sensitivity	10k	Historical	11%	Low	100%	133.5	133.5	133.5	39.9
19	Credible	10k	Historical	9%	High	100%	257.3	257.3	257.3	24.7
20	Credible	10k	Historical	9%	Medium	100%	136.1	136.1	136.1	32.9
21	Credible	10k	Historical	9%	Low	100%	128.9	128.9	128.9	35.5
22	Sensitivity	10k	Historical	7%	High	100%	375.3	375.3	375.3	20.9
23	Sensitivity	10k	Historical	7%	Medium	100%	132.4	132.4	132.4	26.6
24	Sensitivity	10k	Historical	7%	Low	100%	120.5	120.5	120.5	30.4
25	Sensitivity	10k	SRMC	11%	Medium	100%	144.8	144.8	144.8	41.1
26	Sensitivity	10k	SRMC	9%	Medium	100%	139.6	139.6	139.6	35.4
27	Sensitivity	10k	SRMC	7%	Medium	100%	126.5	126.5	126.5	28.7
28	Sensitivity	10k	LRMC	11%	Medium	100%	186.7	186.7	186.7	41.1
29	Sensitivity	10k	LRMC	9%	Medium	100%	197.6	197.6	197.6	35.7
30	Sensitivity	10k	LRMC	7%	Medium	100%	214.1	214.1	214.1	29.2
31	Sensitivity: local generation	10k	Historical	9%	Medium	100%	115.6	115.6	115.6	-2.6
32	Sensitivity: local generation	29.6k	Historical	9%	Medium	100%	144.5	144.5	144.5	-7.7
33	Sensitivity	29.6k	Historical	9%	Medium	110%	174.6	174.6	174.6	31.3
34	Sensitivity	29.6k	Historical	9%	Medium	90%	155.5	155.5	155.5	24.2
35	Sensitivity	10k	Historical	9%	Medium	110%	145.6	145.6	145.6	36.4
36	Sensitivity	10k	Historical	9%	Medium	90%	126.5	126.5	126.5	29.3
37	Sensitivity: +10%ME cost	10k	Historical	9%	Medium	100%	111.5	111.5	111.5	35.5
38	Sensitivity: –10%ME cost	10k	Historical	9%	Medium	100%	175.5	175.5	175.5	35.5
39	Sensitivity: +10%ME cost	29.6k	Historical	9%	Medium	100%	171.2	171.2	171.2	35.5
40	Sensitivity: –10%ME cost	29.6k	Historical	9%	Medium	100%	172.5	172.5	172.5	35.5
	Median for credible scenarios						150.6	150.6	150.6	30.3
	Median for sensitivities						150.6	150.6	150.6	34.9
	Median overall						150.6	150.6	150.6	33.6

Table G.13 The AER's conclusion on total costs ($ million, 1 July 2005)

No.	Total cost scenario	USE value	Bidding strategy	Discount rate	Demand growth	Alternative project costs	Directlink cost	Alternative 1 cost	Alternative 2 cost	Alternative 3 cost
1	Sensitivity	29.6k	Historical	11%	High	100%	186.5	274.4	169.0	87.5
2	Sensitivity	29.6k	Historical	11%	Medium	100%	186.5	274.4	169.0	87.5
3	Sensitivity	29.6k	Historical	11%	Low	100%	186.5	274.4	169.0	87.5
4	Credible	29.6k	Historical	9%	High	100%	189.9	274.8	170.0	88.9
5	Credible	29.6k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
6	Credible	29.6k	Historical	9%	Low	100%	189.9	274.8	170.0	88.9
7	Sensitivity	29.6k	Historical	7%	High	100%	194.8	276.8	172.6	91.8
8	Sensitivity	29.6k	Historical	7%	Medium	100%	194.8	276.8	172.6	91.8
9	Sensitivity	29.6k	Historical	7%	Low	100%	194.8	276.8	172.6	91.8
10	Sensitivity	29.6k	SRMC	11%	Medium	100%	186.5	274.4	169.0	87.5
11	Sensitivity	29.6k	SRMC	9%	Medium	100%	189.9	274.8	170.0	88.9
12	Sensitivity	29.6k	SRMC	7%	Medium	100%	194.8	276.8	172.6	91.8
13	Sensitivity	29.6k	LRMC	11%	Medium	100%	186.5	274.4	169.0	87.5
14	Sensitivity	29.6k	LRMC	9%	Medium	100%	189.9	274.8	170.0	88.9
15	Sensitivity	29.6k	LRMC	7%	Medium	100%	194.8	276.8	172.6	91.8
16	Sensitivity	10k	Historical	11%	High	100%	186.5	274.4	169.0	87.5
17	Sensitivity	10k	Historical	11%	Medium	100%	186.5	274.4	169.0	87.5
18	Sensitivity	10k	Historical	11%	Low	100%	186.5	274.4	169.0	87.5
19	Credible	10k	Historical	9%	High	100%	189.9	274.8	170.0	88.9
20	Credible	10k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
21	Credible	10k	Historical	9%	Low	100%	189.9	274.8	170.0	88.9
22	Sensitivity	10k	Historical	7%	High	100%	194.8	276.8	172.6	91.8
23	Sensitivity	10k	Historical	7%	Medium	100%	194.8	276.8	172.6	91.8
24	Sensitivity	10k	Historical	7%	Low	100%	194.8	276.8	172.6	91.8
25	Sensitivity	10k	SRMC	11%	Medium	100%	186.5	274.4	169.0	87.5
26	Sensitivity	10k	SRMC	9%	Medium	100%	189.9	274.8	170.0	88.9
27	Sensitivity	10k	SRMC	7%	Medium	100%	194.8	276.8	172.6	91.8
28	Sensitivity	10k	LRMC	11%	Medium	100%	186.5	274.4	169.0	87.5
29	Sensitivity	10k	LRMC	9%	Medium	100%	189.9	274.8	170.0	88.9
30	Sensitivity	10k	LRMC	7%	Medium	100%	194.8	276.8	172.6	91.8
31	Sensitivity: local generation	10k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
32	Sensitivity: local generation	29.6k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
33	Sensitivity	29.6k	Historical	9%	Medium	110%	192.0	302.3	187.0	97.8
34	Sensitivity	29.6k	Historical	9%	Medium	90%	187.8	247.3	153.0	80.1
35	Sensitivity	10k	Historical	9%	Medium	110%	192.0	302.3	187.0	97.8
36	Sensitivity	10k	Historical	9%	Medium	90%	187.8	247.3	153.0	80.1
37	Sensitivity: +10%ME cost	10k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
38	Sensitivity: –10%ME cost	10k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
39	Sensitivity: +10%ME cost	29.6k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
40	Sensitivity: –10%ME cost	29.6k	Historical	9%	Medium	100%	189.9	274.8	170.0	88.9
	Median for credible scenarios						189.9	274.8	170.0	88.9
	Median for sensitivities						189.9	274.8	170.0	88.9
	Median overall						189.9	274.8	170.0	88.9

Table G.14 The AER's conclusion on net market benefits ($ million, 1 July 2005)

No.	Net market benefit (NMB) scenario	USE value	Bidding strategy	Discount rate	Demand growth	Alternative project costs	Directlink NMB	Directlink Ranking	Alternative 1 NMB	Alternative 1 Ranking	Alternative 2 NMB	Alternative 2 Ranking	Alternative 3 NMB	Alternative 3 Ranking
1	Sensitivity	29.6k	Historical	11%	High	100%	-13.6	2	-101.5	4	3.9	1	-59.5	3
2	Sensitivity	29.6k	Historical	11%	Medium	100%	-25.8	2	-113.7	4	-8.3	1	-53.1	3
3	Sensitivity	29.6k	Historical	11%	Low	100%	-49.4	3	-137.3	4	-31.9	1	-47.5	2
4	Credible	29.6k	Historical	9%	High	100%	50.1	2	-34.8	3	70.0	1	-64.3	4
5	Credible	29.6k	Historical	9%	Medium	100%	-24.8	2	-109.8	4	-4.9	1	-61.2	3
6	Credible	29.6k	Historical	9%	Low	100%	-58.1	3	-143.1	4	-38.2	1	-53.4	2
7	Sensitivity	29.6k	Historical	7%	High	100%	154.6	2	72.6	3	176.8	1	-70.9	4
8	Sensitivity	29.6k	Historical	7%	Medium	100%	-21.6	2	-103.6	4	0.6	1	-72.5	3
9	Sensitivity	29.6k	Historical	7%	Low	100%	-72.9	3	-154.9	4	-50.7	1	-61.5	2
10	Sensitivity	29.6k	SRMC	11%	Medium	100%	-40.8	2	-128.7	4	-23.3	1	-42.2	3
11	Sensitivity	29.6k	SRMC	9%	Medium	100%	-48.4	2	-133.3	4	-28.5	1	-49.3	3
12	Sensitivity	29.6k	SRMC	7%	Medium	100%	-64.5	3	-146.5	4	-42.3	1	-58.9	2
13	Sensitivity	29.6k	LRMC	11%	Medium	100%	12.8	2	-75.1	4	30.3	1	-39.2	3
14	Sensitivity	29.6k	LRMC	9%	Medium	100%	22.5	2	-62.5	4	42.4	1	-45.7	3
15	Sensitivity	29.6k	LRMC	7%	Medium	100%	37.3	2	-44.7	3	59.5	1	-54.4	4
16	Sensitivity	10k	Historical	11%	High	100%	-1.9	2	-89.8	4	15.6	1	-59.5	3
17	Sensitivity	10k	Historical	11%	Medium	100%	-47.0	2	-134.9	4	-29.5	1	-49.4	3
18	Sensitivity	10k	Historical	11%	Low	100%	-52.9	3	-140.8	4	-35.4	1	-47.5	2
19	Credible	10k	Historical	9%	High	100%	67.4	2	-17.5	3	87.3	1	-64.3	4
20	Credible	10k	Historical	9%	Medium	100%	-53.8	2	-138.8	4	-33.9	1	-56.1	3
21	Credible	10k	Historical	9%	Low	100%	-61.0	3	-145.9	4	-41.1	1	-53.4	2
22	Sensitivity	10k	Historical	7%	High	100%	180.5	2	98.5	3	202.7	1	-70.9	4
23	Sensitivity	10k	Historical	7%	Medium	100%	-62.3	2	-144.3	4	-40.1	1	-65.2	3
24	Sensitivity	10k	Historical	7%	Low	100%	-74.3	3	-156.3	4	-52.1	1	-61.5	2
25	Sensitivity	10k	SRMC	11%	Medium	100%	-41.6	2	-129.5	4	-24.1	1	-46.4	3
26	Sensitivity	10k	SRMC	9%	Medium	100%	-50.3	2	-135.2	4	-30.4	1	-53.6	3
27	Sensitivity	10k	SRMC	7%	Medium	100%	-68.3	3	-150.3	4	-46.1	1	-63.2	2
28	Sensitivity	10k	LRMC	11%	Medium	100%	0.3	2	-87.6	4	17.8	1	-46.3	3
29	Sensitivity	10k	LRMC	9%	Medium	100%	7.7	2	-77.3	4	27.6	1	-53.3	3
30	Sensitivity	10k	LRMC	7%	Medium	100%	19.3	2	-62.7	4	41.5	1	-62.6	3
31	Sensitivity: local generation	10k	Historical	9%	Medium	100%	-74.3	2	-159.3	4	-54.4	1	-91.6	3
32	Sensitivity: local generation	29.6	Historical	9%	Medium	100%	-45.4	2	-130.3	4	-25.5	1	-96.7	3
33	Sensitivity	29.6k	Historical	9%	Medium	110%	-17.3	2	-127.7	4	-12.4	1	-66.5	3
34	Sensitivity	29.6k	Historical	9%	Medium	90%	-32.4	2	-91.9	4	2.5	1	-55.8	3
35	Sensitivity	10k	Historical	9%	Medium	110%	-46.3	2	-156.7	4	-41.4	1	-61.4	3
36	Sensitivity	10k	Historical	9%	Medium	90%	-61.3	3	-120.9	4	-26.5	1	-50.7	2
37	Sensitivity: +10%ME cost	10k	Historical	9%	Medium	100%	-78.3	3	-163.3	4	-58.4	2	-53.4	1
38	Sensitivity: –10%ME cost	10k	Historical	9%	Medium	100%	-14.4	2	-99.3	4	5.5	1	-53.4	3
39	Sensitivity: +10%ME cost	29.6k	Historical	9%	Medium	100%	-18.7	2	-103.6	4	1.2	1	-53.4	3
40	Sensitivity: –10%ME cost	29.6k	Historical	9%	Medium	100%	-17.4	2	-102.4	4	2.5	1	-53.4	3
	Median for credible scenarios						-39.3	2	-124.3	4	-19.4	1	-58.6	3
	Median for sensitivities						-36.6	2	-124.3	4	-17.8	1	-54.0	3
	Median overall						-36.6	2	-124.3	4	-17.8	1	-55.1	3

Appendix H Weighted average cost of capital

This appendix sets out the capital asset pricing model (CAPM) used to estimate the cost of equity capital in section H.1. It also addresses the individual parameters and related matters found in the weighted average cost of capital (WACC) and CAPM framework:

- the risk-free rate (section H.2)
- the inflation rate (section H.3)
- the market risk premium (MRP) (section H.4)
- betas (section H.5)
- gearing (section H.6)
- the cost of debt (section H.7)
- franking credits—gamma (section H.8)
- debt and equity raising costs (section H.9)
- taxation (section H.10).

H.1 The capital asset pricing model

Clause 6.2.2(b)(2) of the National Electricity Code (the code) states that the regulatory regime administered by the AER must provide for:

> … a sustainable commercial revenue stream, which includes a fair and reasonable rate of return to Transmission Network Owners and/or Transmission Network Service Providers on efficient investment, given efficient operating and maintenance practices.

Various methods can be applied to estimate the return on equity (r_e) as outlined under schedule 6.1(2.2) of the code—for example, price to earning ratios, the dividend growth model or arbitrage pricing theory. The code indicates, however, that the CAPM remains the most widely accepted practical tool to estimate the cost of equity.

The CAPM calculates the required return given:

- the opportunity cost of investing in the market
- the market's own volatility
- the systematic risk of holding equity in the particular company.

The CAPM formula is:

$$r_e = r_f + \beta_e(r_m - r_f)$$

where:

r_e	=	the required rate of return on equity or cost of equity
r_f	=	the expected risk–free rate of return (usually based on government bond rates of an appropriate tenure)
$r_m - r_f$	=	the expected MRP, which measures the return of the market as a whole less the risk-free rate for the same period
β_e	=	the systematic risk (equity beta) of the individual company's equity relative to the market.

Businesses are typically funded by equity and debt, however, so including the cost of debt allows the corresponding return on capital employed to be derived. This is known as the WACC (section 13.3). The determination of the WACC requires several parameters, which are discussed below.

H.2 Estimate of the risk-free interest rate

The risk-free rate measures the return that an investor would expect from an asset with zero volatility and zero default risk. The yield on long term Australian Government securities (bonds) is used as a proxy for the risk-free rate because the risk of government default on interest and debt repayments is generally considered to be very low. The two considerations are the sampling period used to determine the risk-free rate and the term of the risk-free rate.

In the CAPM framework, all information used for deriving the rate of return should be as up to date as possible when the decision comes into effect. In the case of interest rates and inflationary expectations, financial markets determine these on a continuous basis. On this issue, the Australian Competition and Consumer Commission's (ACCC) *Statement of Principles for the Regulation of Electricity Transmission Revenues* (SRP) noted that:

> … the period (between 5 to 40 days) used to calculate the moving average of the bond rate should be left to the discretion of the TNSP [transmission network service provider] when making its application. However, the TNSP will not be allowed to change the averaging period after its application is lodged.[167]

H.2.1 DJV's application

Sampling period

DJV did not specify a preferred sampling period in its application. But it applied the ACCC's standard approach for deriving the nominal risk-free rate of using a recent average of the yield on bonds.

[167] ACCC, *Statement of Principles for the Regulation of Electricity Transmission Revenues*, 8 December 2004, p. 98.

Term of the risk-free interest rate

DJV proposed that a 10 year bond rate be used, in conjunction with a 10 year regulatory control period. It considered, however, that its use of 10 year bonds is the correct approach irrespective of the length of the regulatory period. It stated that the bond term should reflect the term of the investment being considered. For transmission investments, DJV considered that this term is far longer than the regulatory control periods and that the bond maturity should be matched to the life of the assets or the yield on the longest traded bond.

H.2.2 The AER's considerations

Sampling period

The AER is aware of the inherent limitations of using either an 'on-the-day' rate or a short term 'historical average' in calculating the risk-free rate. The financial theory underlying the CAPM specifies the use of ex ante returns. Using an on-the-day rate gives the best estimate of ex ante returns, so theoretically it is more appropriate. But an on-the-day rate may reflect short term fluctuations that may differ from the long term trend. Such market volatility can be minimised by averaging rates over some time before the start of the regulatory period. Several regulators have traditionally used a short term average rate as the risk-free rate.

The ACCC formerly adopted a 40 day moving average and used it in several of its earlier regulatory decisions. More recently, however, it has used a 10 day moving average in its Tasmanian, Victorian, South Australian and New South Wales revenue cap decisions.[168] DJV has not expressed a specific sampling period. Consistent with the SRP and recent decisions, the AER proposes to sample a 10 day moving average of the yield on bonds.

Term of the risk-free interest rate

The AER notes that some interested parties supported using the risk-free interest rate that matches the length of the regulatory period. Alternatively, others argued for using bond rates with terms matching the life of the assets. The latter suggested that 10 year bond yields should be used in the CAPM formula because transmission assets have long effective lives, far exceeding the term of the most traded Australian bond with the longest maturity period (that is, 10 years).

In December 2003, the Australian Competition Tribunal handed down its decision on the review of the ACCC's tariff determination for transportation services on GasNet's Victorian natural gas transmission network.[169] The tribunal accepted GasNet's approach to calculating the risk-free rate on the basis of a 10 year Commonwealth bond rate, although the ACCC used a five year rate. The tribunal cited the traditional application of the CAPM and estimation of the MRP based on a 10 year time horizon

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[168] id., *Tasmanian Transmission Network Revenue Cap 2004–2008-09*, Canberra, 10 December 2003; id., *Victorian Transmission Network Revenue Caps 2003–2008*, Canberra, 11 December 2002; id., *South Australian Transmission Network Revenue Cap 2003–2007-08*, Canberra, 11 December 2002; ACCC, *NSW and ACT Transmission Network Revenue Cap: EnergyAustralia 2004-05 – 2008-09*, Canberra, 27 April 2005; id., *NSW and ACT Transmission Network Revenue Cap: TransGrid 2004-05 – 2008-09*, Canberra, 27 April 2005.

[169] id., *GasNet Access Arrangement 2004-05 – 2008-09*, Canberra, January 2002.

as the basis for its decision. It considered that the service provider, under the terms of the Gas Code, is entitled to use a CAPM calculation based on a 10 year horizon as a legitimate basis for estimating the cost of equity.

Given the tribunal's decision, the ACCC stated in the SRP that it would adopt a 10 year Commonwealth bond rate as a proxy for the risk-free rate. The AER will adopt this approach set out in the SRP for estimating the risk-free rate.

Maturity dates on the nominal and indexed bonds rarely correspond and require re-alignment using either interpolation or extrapolation (that is, by estimating the rate at a given moment from a 'line of best fit'). The ACCC has used this approach in all of its revenue cap decisions, which is also consistent with jurisdictional regulatory decisions.

A yield could be expressed for any defined period, but typically it is convenient to quote annual rates. With bonds, the convention in Australia to obtain annual rates is to double an effective half yearly rate. The use of effective half yearly rates is due to interest normally being paid half yearly. This doubling of the half yearly rate is regarded as a nominal rate. An adjustment is thus required to obtain an effective annual rate that accounts for the compounding effect over the year. The AER has made the relevant adjustment to the quoted bond yield. For this draft decision, the use of the nominal 10 year bond rate and 10 day moving average for Commonwealth bond rates at 1 June 2005 results in a proxy risk-free rate of 5.50 per cent (effective annual compounding rate).[170]

H.3 Expected inflation rate

The expected inflation rate is not an explicit parameter in the return on equity calculation. It is a component of the nominal risk-free rate (which has implications for the cost of both debt and equity) that can be estimated by:

- the difference between the nominal and indexed bond yields, or
- Commonwealth Treasury's inflation forecasts.

The ACCC has historically forecast the inflation rate as the difference between the nominal bond rate and the inflation indexed bond rate, as determined using the Fisher equation.[171]

H.3.1 DJV's application

DJV sought the ACCC's assurance that both the revenue cap for the first regulatory period and the roll-forward of its regulatory asset base at the subsequent price review will be adjusted to reflect the difference between actual and forecast inflation. It noted that if the regulatory regime does not offer protection against inflation risk,

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170 Source: UBS AG Australia.

171 The use of the 10 year and 10 day moving average for the inflation indexed bond rates at 28 October 2005 results in a real risk-free rate of 2.64 per cent (annual compounding rate).

then it would face substantially higher risk and require a commensurately higher return.

H.3.2 The AER's considerations

The AER considers that DJV's proposal is valid and consistent with current regulatory practice. This method of adjusting the revenue cap for actual inflation is set out in appendix I and is consistent with the SRP. For this draft decision, the AER forecasts inflation of 2.79 per cent per year.

H.4 Market risk premium

The MRP is the margin above the risk-free rate of return that investors expect to earn if they hold the market portfolio—that is, the return of the market as a whole minus the risk–free rate:

$$\text{MRP} = r_m - r_f$$

Under a classical taxation system, conventional thinking suggests a value for the MRP of around 6 per cent. Determination of the return on capital for a regulated business is a forward looking process. Estimates of the future cost of equity are not readily available, however. Practical applications of the CAPM, therefore, often rely on the analysis of historical returns to equity when estimating the MRP.

H.4.1 DJV's application

DJV proposed an MRP of 6 per cent in its application, but considered this to be at the low end of the feasible range. It advocated the use of long term historical averages to estimate the MRP. In its application, DJV found the MRP calculated from the longest period of observations to be around 7.2–7.3 per cent. While the MRP calculated from more recent data is lower—6.5 per cent for the post-war period and 3.4 per cent for the period from 1970—DJV considered that the statistical uncertainty of estimates is so great as to make the average premium calculated over this shorter period meaningless.

DJV argued that the use of alternative methods for estimating the premium, such as ex ante models, does not provide sufficiently reliable evidence to justify the rejection of the historical premium. Surveys suffer from flaws (including low response rate and question ambiguity) and do not estimate what investors require, only what particular market participants with their own interests *report* that investors require. DJV thus stated that any view that the MRP is below 6 per cent is not based on any robust market evidence and should not be accorded any weight.

H.4.2 The AER's considerations

Despite a substantial amount of research of the MRP, there is continuing debate about the appropriate value. Recent decisions by the ACCC have supported an MRP of 6 per cent as well as arguments for both higher and lower values from interested parties.

Historical measures

The rationale for using historical data as a measure of the expected MRP is that investors' expectations will be framed on the basis of the market's past performance. The AER considers the value of the MRP, based on a traditional long term view using historical measures (the ex post measure), remains around 6 per cent.[172] The MRP appears to have fallen to around 3–4 per cent over recent years,[173] but the AER notes that this may reflect short term market trends. Further, statistical estimates over shorter periods tend to provide standard errors that are typically higher than the mean estimates, so should be interpreted with caution.

The UK market risk premium and the ex ante method

The UK regulators appear to use a forward looking MRP, based on an ex ante (supply-side) approach. The ex ante approach estimates the MRP as the sum of the expected dividend yield and the expected capital gain from shares. The MRP estimates from an ex ante approach are generally lower than historical estimates of MRP. UK regulators typically apply an MRP in the range of 3.5–5.0 per cent.[174] Australian applications of similar ex ante approaches have arrived at an estimate of 4.0–5.7 per cent.[175] A major part of the difference appears to be driven by the Australian assumption of a significantly higher long run growth in gross domestic product.

Most research on the ex ante approach has been undertaken in the United States, with some showing an MRP of approximately 3–4 per cent.[176] Given the relatively limited research on the Australian application of the ex ante approach, these results must be interpreted with caution. The AER thus considers that it is not appropriate to rely exclusively on the ex ante approach for estimating an MRP.

Benchmarking of international data

An alternative approach for determining the Australian MRP is to benchmark international data. A study by Bowman estimated the Australian MRP to be 7.8 per cent, using the benchmarking approach on the basis of:

- a US MRP of 6–9 per cent
- adjustments made for incremental risk factors of 0.1–2.4 per cent on the US MRP for differences in taxation, market, country risk and time horizon.[177]

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172 There appears to be consensus that the MRP cannot be easily predicted over shorter periods and is likely to have poor statistical properties.

173 Headberry Partners and Bob Lim, *Further Capital Markets Evidence in Relation to the Market Risk Premium and Equity Beta Values for ECCSA*, , December 2003, p. 48.

174 The Allen Consulting Group (ACG), *Review of Studies Comparing International Regulatory Determinations: Final Report to the ACCC*, March 2004, p. ix.

175 M Lally, *The Cost of Capital under Dividend Imputation*, Wellington, June 2002, pp. 29–34.

176 J Claus and J Thomas, 'Equity premia as low as three percent? Evidence from analysts' earnings forecasts for domestic and international stocks', *The Journal of Finance*, vol. 56, 2001, pp. 1629–66; ACG, *Review of Studies Comparing International Regulatory Determinations: Final Report to the ACCC*, Sydney, March 2004, p. viii.

177 J Bowman, *Estimating the Market Risk Premium: The Difficulty with Historical Evidence and an Alternative Approach*, *Journal of the Securities Institute (JASSA)*, issue 3, 2001.

The AER is cautious about this approach. Apart from the issues associated with estimating the US MRP, the benchmarking approach also involves estimating adjustment factors, which are arbitrary and add more doubt to the accuracy of the estimation.

Survey data

Another approach to determining the MRP is using survey data. This approach has problems, however, because surveys are conducted at a specific point in time and may reflect only transient market sentiments. The reliability of survey data is also a concern. Common issues include obtaining a representative sample and framing the survey so as not to induce bias in respondents. Given general concerns about the reliability of survey data, the AER will consider, but not place much weight on, survey data.

Consultancies

A study undertaken by Associate Professor Lally, on behalf of the ACCC, assessed various approaches to estimating the MRP. Across four different approaches (including historical and ex ante methods), Lally determined that the average estimate for the MRP in Australia is 6.1 per cent.[178] He concluded that:

> … the range of methodologies examined give rise to a wide range of possible estimates for the market risk premium and these estimates embrace the current value of 6%. Accordingly the continued use of the 6% estimate is recommended.[179]

The Allen Consulting Group (ACG) also reviewed the empirical evidence on the Australian MRP. Based on evidence that included an analysis of international trends in the MRP, the ACG concluded that:

> … there is no justification for applying an MRP different from 6%, as is the practice of Australian regulators. [180]

While the point estimate of the MRP provided by historical evidence suggests a higher figure, the ACG noted that the qualitative and empirical evidence from ex ante models provide persuasive evidence that 6 per cent overstates the expected MRP.

Conclusion

The information prepared by Lally and the ACG demonstrates that 6 per cent is an appropriate balance of the available evidence on the MRP. Although historical premiums typically suggest a higher MRP than 6 per cent, more recent estimates and forward looking estimates typically suggest a lower MRP than 6 per cent. For this draft decision, therefore, the AER will use an estimate of 6 per cent for the MRP, but it will continue to monitor the available research.

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178 This average was derived using: historical averaging of the Ibbotson type (0.07), historical averaging of the Siegel type (0.056), the Merton method (0.07) and 0.04–0.057 from the forward looking approach with a point estimate of 0.048.

179 Lally, op. cit., p. 34.

180 ACG, *Review of Studies Comparing International Regulatory Determinations*, op. cit., p. 113.

H.5 Betas and risk

The equity beta is a measure of the expected volatility of a particular stock relative to the market portfolio. It measures the systematic risk of the stock—that is, the risk that cannot be eliminated in a balanced and diversified portfolio. Generally, the Australian stock index is used as a proxy for the market portfolio. An equity beta of less than 1 indicates that the stock has a low systematic risk relative to the market (the market portfolio beta being equal to 1). Conversely, an equity beta of more than 1 indicates the stock has a high systematic risk relative to the market.

Calculating equity betas for publicly listed companies is straightforward. A company's return is calculated by adding the dividend income to changes in the value of the stock. Then, the company's return is compared to the market return. Market return is calculated in the same way—that is, by adding the dividends and changes in values of all the companies listed on the Australian Stock Exchange (ASX).

Calculating equity betas for unlisted firms is more complicated because their returns cannot be calculated directly. Conventional practice is to establish the beta of a similar listed company or the average beta for the sector, and then adjust it. For Australian regulated electricity networks, even this approach is problematic because few similar stocks are listed. In any case, listed companies often include unregulated business units so are not always a perfect indicator of the systematic risk of a transmission network service provider (TNSP).

The equity beta of a firm may also depend on its capital structure. For estimating the beta of a regulated firm, therefore, the beta of the comparable (listed) firm must be adjusted for differences in capital structure. Usually, the first step is to establish the equity beta of a firm. Then, by 'de-levering' it to approximate a firm without debt (100 per cent equity), the 'asset' or 'un-levered' beta is derived.

The asset beta should be similar for all firms in a similar business. The equity beta for a geared business is obtained by 're-levering' the asset beta with the actual gearing ratio of the business. While there is a number of levering formulae, the ACCC has generally applied the formula developed by Monkhouse because it is appropriate for Australia's tax environment:

$$\beta_e \quad = \quad \beta_a + (\beta_a - \beta_d)\left[1 - 1 - \left(\frac{r_d}{1 + r_d}\right)(1 - \gamma)\, T_e\right] D/E$$

where:

β_e	=	the equity beta
β_i	=	the asset beta
β_d	=	the debt beta
r_d	=	the cost of debt
γ	=	gamma
T_e	=	the effective tax rate

E = the market value of equity

D = the market value of debt.

The debt beta captures the systematic risk of debt and is used in the Monkhouse formula. It represents that part of systematic risk in business operations transferred from equity holders to providers of debt. The impact of the debt beta is thus to diminish the estimated value of the equity beta based on a particular value for the asset beta.

H.5.1 DJV's application

DJV adopted a debt beta of 0, combined with an asset beta of 0.45, which together with other proposed parameters provide a re-levered equity beta of 1.13. It claimed that the ACCC's view (that an equity beta of 1 is appropriate) rests on an exclusive reliance of beta estimates for a small number of listed Australian utilities. Instead, where there is not a significant portfolio of comparator stocks trading in the local market, DJV used a larger sample of comparable international businesses, taking beta estimates measured against their respective domestic markets.

DJV relied on the estimates of betas that the Network Economics Consulting Group (NECG) undertook in its submission to the ACCC.[181] There are 11 companies in the transmission only sample, selected from Spain, Chile, Malaysia, Brazil, Russia and the United States. According to the NECG results, the average asset beta for the transmission only businesses is 0.45, which translates into a re-levered equity beta of 1.13 (assuming debt beta of 0 and 60 per cent level of gearing).

DJV further contended that the ACCC is incorrect in comparing the equity beta for TNSPs and the market average beta of 1 without adjusting for differences in gearing.

H.5.2 The AER's considerations

Equity beta

In previous ACCC revenue cap decisions, an equity beta estimate of 1 was adopted. This assumes that the TNSP experiences the same volatility as does the market portfolio in general. This is not consistent, however, with the frequently held view that gas and electricity transmission businesses are less risky relative to the market, irrespective of a higher average level of gearing. This view is based on the earnings of gas and electricity businesses being seemingly more stable than those of most other businesses in the market. Greater stability of cash flow suggests that the equity beta should be less than 1.

In the SRP, the ACCC noted that market evidence shows regulated energy firms listed on the ASX have an equity beta of below 1 (after adjusting for gearing differences) and thus do not face the same market risk relative to the market portfolio

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181 NECG, *2003 Review of draft statement of regulatory principles for the regulation of transmission revenues, submission to the ACCC for the electricity TNSPs from Network Economics Consulting Group*, Sydney, 2003, pp. 53–6.

beta. Table H.1 lists the equity betas for recent regulatory decisions by other jurisdictional regulators.[182]

Table H.1 Recent regulatory decisions on equity betas for electricity industry

Decision	Network type	Equity beta
Independent Pricing and Regulatory Tribunal, NSW (2004)	Distribution	0.8–1.1
Independent Competition and Regulatory Commission, Australian Capital Territory (2004)	Distribution	0.9
Essential Services Commission, Victoria (2000)	Distribution	1.0
Queensland Competition Authority (2005)	Distribution	0.9
Essential Services Commission of South Australia (2005)	Distribution	0.8
Essential Services Commission, Victoria (2005)—draft	Distribution	1.0

Asset beta

The asset beta is relevant only within the de-levering and re-levering processes. It is simply the equity beta for a firm that is 100 per cent equity financed and has no debt in its capital structure. It is not observable but can be calculated by de-levering the observed equity beta.

Debt beta

A debt beta estimate of 0 has been applied in previous ACCC electricity revenue cap decisions. The ACCC considered that a relatively low debt beta is appropriate because the systematic risk of debt is low (given the risk of debt is primarily related to default risk), so treated the debt beta as a residual parameter. An ACG report prepared for the ACCC considered this information and suggested that an appropriate range for the debt beta would be 0.0–0.15.[183] Nonetheless, as long as the value of the debt beta is consistent between the de-levering and re-levering processes, its effect on the equity beta is generally negligible.

Beta and gearing of the market

The AER notes DJV's comment that it is incorrect to compare the equity beta for TNSPs and the market average beta of 1 without adjusting for differences in gearing. As stated in the SRP, by definition, the market portfolio beta has a value of 1 and

182 Some of these regulators have used weekly market beta estimates in their analysis.

183 ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities: Final Report for the ACCC*, July 2002, pp. 28–9.

does not require any gearing assumption.[184] If a stock has an equity beta of 1, it simply implies that the equity returns on the stock have the same systematic risk as that of the market portfolio.

A number of factors can affect the beta for a firm within the market portfolio, however, including gearing.[185] The practice is to pool a sample of comparable firms that would normalise these factors affecting the beta as much as possible. Gearing is assumed to be the remaining factor for adjustment and is undertaken in the de-levering/re-levering processes.

Estimating equity beta from international market data

Specific differences need to be taken into account when comparing WACC parameters across countries, including:

- differences in the size and composition of share markets
- varying taxation regimes across countries
- differences in market average levels of gearing
- different incentive mechanisms and regulatory approaches.

The NECG's transmission only sample includes companies from Spain, Chile, Malaysia, Brazil, Russia and the United States.[186] There is no analysis of the comparability between the Australian economy and share market, and the economies and share markets of each of the comparator countries. There is also no analysis of the regulatory regimes that apply to the comparator companies. The regulatory regime in Australia is likely to have a substantial impact on betas as a result of stable and predictable returns.

Of all the countries in the NECG sample, only Spain and the United States are member countries of the Organisation for Economic Cooperation and Development (OECD). For a country to belong to the OECD (of which Australia is a member), it must have demonstrated its commitment to the basic values shared by all OECD members: an open market economy, democratic pluralism and respect for human rights. It must also show both the will and the ability to adopt the main principles of the organisation, as well as the legal and political obligations that result. It can be argued, therefore, that these countries are likely to share more similarities in their economies than with non-OECD countries. The AER considers that comparing WACC parameters across non-OECD countries, without analysis and adjustment, is likely to result in a flawed estimate.

The Independent Competition and Regulatory Commission (ICRC) of the Australian Capital Territory recently re-evaluated the average betas from the NECG data using

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184 ACCC, *Statement of Principles*, op. cit., pp. 106–7.

185 Such factors can include the nature of the firm's output, the duration of contracts, regulation, monopoly power, operating leverage, real options, industry size and capital structure.

186 NECG, op. cit., pp. 53–6.

only OECD countries.[187] The average asset beta for the 54 observations from OECD countries was 0.33. Applying the NECG's approach results in an asset beta in the range 0.34–0.42 and a calculated equity beta in the range 0.76–1.04.

Estimating equity beta from Australian market data

The ACG report to the ACCC on proxy beta values in 2002 suggested an equity beta for Australian gas transmission companies of just below 0.7, based only on market evidence.[188] The ACG also considered data for comparable businesses in the United States, Canada and the United Kingdom. These data produced lower beta estimates, and the ACG concluded that this secondary information supports the view that Australian estimates are not understated. Given several qualifications to its analysis, however, the ACG did not recommend relying on only domestic empirical information. It instead recommended that Australian regulators retain a conservative approach with an equity beta estimate of 1. It noted that:

> In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[189]

As shown in table H.2, the AER has derived re-levered equity betas for five comparable Australian firms based on March 2005 and June 2005 data from the Australian Graduate School of Management (AGSM).[190, 191] For calculation purposes, it has had regard to raw (unadjusted) beta estimates, the debt beta was set at zero, and the corresponding gearing levels were from Standard and Poor's.[192] The sample market beta estimates (average re-levered beta of 0.2 in March 2005 and average re-levered beta of 0.2 in June 2005) suggest that the ACCC has been conservative with its equity beta estimate of 1 in previous regulatory decisions.

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187 ICRC, *Final Decision—Review of Access Arrangement for ActewAGL Natural Gas System in ACT, Queanbeyan and Yarrowlumla*, Canberra, October 2004, p. 153.

188 ACG, *Empirical Evidence on Proxy Beta Values*, op. cit., p. 46.

189 ibid., p. 43.

190 These firms are comparable because they operate in a line of business (regulated networks) similar to that of the target firm, such that the systematic risk of the underlying assets is likely to be of similar magnitude. Some of these firms are involved in other business areas (non-regulated), however, which means the systematic risk of a target regulated network firm is likely to be overstated.

191 The AGSM uses monthly observations over 48 months of a firm's trading history (with a minimum of 20 observations).

192 Standard and Poor's, *Australian Report Card: Utilities*, March 2005; id., *Australia & New Zealand CreditStats*, June 2004.

Table H.2 Comparable sample betas

Company	Gearing	March 2005 AGSM data			June 2005 AGSM data		
		Unadjusted β_e	De-levered β_a	Re-levered β_e	Unadjusted β_e	De-levered β_a	Re-levered β_e
Australian Pipeline Trust	66.4	0.6	0.2	0.5	0.6	0.2	0.5
Envestra	80.8	0.3	0.1	0.1	0.1	0.0	0.1
AlintaGas	56.2	0.4	0.2	0.4	0.4	0.2	0.4
Australian Gas Light	40.8	0.0	0.0	0.0	0.1	0.0	0.1
GasNet	69.8	0.2	0.0	0.1	0.1	0.0	0.1
Average	62.8	0.3	0.1	0.2	0.3	0.1	0.2

In the SRP, the ACCC stated that emerging market data suggested the appropriate equity beta for TNSPs may be less than 1. It also stated that it would continue to undertake work in this area. Current statistical methods for estimating the equity beta from market data tend to produce varying confidence interval (and sample average) estimates. In this context, the AER notes that recent jurisdictional regulatory decisions provided analysis of a comparable sample of equity betas based on monthly and weekly observations, which produced varied results.[193] The weekly beta estimates tend to be higher than the monthly beta estimates.

In the SRP, the ACCC noted that the estimated re-levered equity betas for comparable firms fell from around 1 in 2000 to around 0.2 in 2003.[194] This fall is consistent with the ACCC's estimates of market derived equity betas considered in recent regulatory decisions. The AER considers that the time period of the market data may not yet be long enough to satisfy the concern that market derived equity betas would not systematically undercompensate the TNSPs. That is, the current decline in the measures of beta from market evidence may reflect a short term deviation from normal trend.

Conclusion

The AER will continue to exercise judgment in applying empirical evidence from the market. On balance, an equity beta of 1 adequately compensates DJV for its systematic risk,[195] despite DJV's claim for an equity beta higher than 1 and the precedent set by some jurisdictional regulators in moving to an equity beta of below

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193 Essential Services Commission of South Australia (ESCOSA), *2005-2010 Electricity Distribution Price Determination Part A—Statement of Reasons, April*, Adelaide, 2005, pp. 138–140; Queensland Competition Authority (QCA), *Regulation of Electricity Distribution—Draft determination*, Brisbane, 2004, pp. 102–3.

194 The re-levered betas, derived from the earlier years, were drawn from a very small market sample that included riskier business activities and thus might not be a useful proxy.

195 The equity beta of 1 is not re-levered from a debt beta of 0 and an asset beta of 0.4. There were no comparable Australian market based data on equity betas that re-levered to an asset beta of 0.4.

1. In future decisions, however, the AER may place greater weight on contemporary market information as this information becomes more reliable in determining appropriate equity beta values.

H.6 Gearing

The AER uses benchmark gearing in determining the WACC, rather than actual gearing. Schedule 6.1(5.5.1) of the code states that:

> Gearing should not affect a government trading enterprise's target rate of return … For practical ranges of capital structure (say less than 80 per cent debt), the required rate of return on total assets for a government trading enterprise should not be affected by changing debt to equity ratios.

H.6.1 DJV's application

DJV adopted the ACCC's benchmark gearing of 60 per cent in its application.

H.6.2 The AER's considerations

In determining a required rate of return, the AER adopts the accepted practice of calculating the WACC based on a capital structure of equity and debt financing. A gearing ratio is thus needed to establish a TNSP's appropriately weighted average cost of debt and equity. The AER's regulatory regime is both light handed and incentive based. It sets the benchmarks, allowing regulated entities to operate their financing arrangements freely. The entities gain by performing better than the benchmarks and conversely lose when performing lower than the benchmarks. Accordingly, in the SRP, the ACCC stated that it would not use the actual gearing of a TNSP, but an appropriate benchmark instead.

A firm's capital structure (expressed as gearing) is unlikely to affect its WACC. Typically, regulators have assumed gearing of 60 per cent in calculating the WACC. This WACC should still apply within reasonable range of actual gearing—say, 40–70 per cent.[196] The AER notes that a Standard and Poor's survey suggested gearing ratios for transmission and distribution businesses are between 55 per cent and 65 per cent.[197] Table H.3 provides a gearing sample of electricity network companies. It shows an average gearing of approximately 57 per cent, which is close to the assumed benchmark gearing of 60 per cent.[198]

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196 Bob Officer, *A Weighted Average Cost of Capital for a Benchmark Australian Electricity Transmission Business—a Report for SPI PowerNet*, Melbourne, February 2002, p. 38.

197 Standard and Poor's, *Rating Methodology for Global Power Companies*, 1999.

198 Some of the electricity companies listed in the table operate not only in the regulated transmission and distribution sectors but also in unregulated areas such as retail and generation.

Table H.3 Gearing of gas and electricity companies

Company	Actual gearing (%)
AlintaGas	61.9
Aurora Energy	52.0
Australian Gas Light	40.8
Australian Pipeline Trust	66.4
Citipower Trust	54.1
Country Energy	67.8
ElectraNet	71.9
Energex	55.3
EnergyAustralia	52.5
Envestra	80.8
Ergon Energy	46.0
ETSA Utilities	64.1
GasNet	69.8
Integral Energy	54.7
Powercor Australia	38.1
SPI PowerNet	76.8
TransGrid	55.3
Western Power	62.5
Average electricity	56.6
Average all	59.5

Source: Standard and Poor's, *Australian Report Card Utilities*, March 2005; id., *Australia and New Zealand CreditStats*, June 2004.

Given the average level of gearing in the electricity network industry, the AER will adopt DJV's proposed benchmark gearing ratio of 60 per cent.

H.7 Cost of debt

As noted in section H.1, businesses issue debt to fund their operations. Including the weighted average cost of debt with the return on equity is referred to as the WACC. In theory, the cost of debt estimation should be the expected return required by investors of debt securities. In practice, the yield to maturity is typically used even though this yield assumes no default and thus exceeds the expected return when there is default risk.[199]

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[199] K Davis, *Report on Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Melbourne, May 2003, p. 12.

A common approach by regulators, in estimating the required return for corporate debt, is to add a premium to the yield on an equivalent maturity risk-free security. Accordingly, the cost of debt is the debt margin plus the risk-free rate:

$$r_d = r_f + d_m$$

where:

r_d = the cost of debt

r_f = the risk-free rate of return

d_m = the debt margin.

The debt margin varies depending on the entity's gearing and credit rating and the term of the debt. Applying the cost of debt (as a percentage) to the regulated asset base (RAB), using the assumed gearing, will generate the interest expense for regulatory purposes. This interest expense is also known as the cost of debt building block in the allowed revenue.

The SRP stated:

> Once the relevant credit rating is established the debt margin can be determined from financial market sources. The debt margin (short term averaging period equal to the averaging of the risk-free rate) should also reflect the prevailing market rates which represent current market expectations for debt issues at the benchmark maturity and credit rating for the regulated entity.[200]

H.7.1 DJV's application

Credit rating and gearing

DJV has adopted a credit rating of BBB+ for a utility company with benchmark gearing of 60 per cent. It argued that the ACCC's approach of including government owned entities in the sample of firms from which it observes its benchmark gearing level is inappropriate. It claims that this approach has led the ACCC to overstate the credit rating that a transmission entity with the benchmark level of gearing could maintain.

DJV noted the difficulties associated with establishing the appropriate value of debt (as a proportion of assets) for government owned entities. The relevant measure of gearing in finance generally is the ratio of the market value of debt to the market value of the asset. For privately owned firms that are listed on the share market, the market value of the firm can be directly observed from the share price data. DJV is concerned that the only proxy for the market value of government owned firms is book value, which does not reflect prevailing market values.

Term of the debt

DJV has adopted the long term average of the debt margin predicted by the CBASpectrum service. This provides a benchmark debt margin of 1.5 per cent.

200 ACCC, *Statement of Principles*, op. cit. p. 113.

DJV noted that it is the ACCC's practice to derive the debt margin using a short term average of the debt margins provided by the CBASpectrum service.

DJV submitted that the predicted margins for BBB+ bonds have been highly variable over short periods. The thin sample of long dated, low rated bonds implies that much of the variation in the predicted yields most likely reflects statistical error in the estimation procedure, rather than truly reflecting changes in the market cost of debt. Given this statistical error, DJV questioned whether it is appropriate to rely on these predicted yields for regulatory purposes.

DJV conceded, however, that to the extent of reliance on the CBASpectrum database, the volatility in the predicted yields implies that the use of a short term average is inappropriate. Given the statistical errors tend to cancel out over time, DJV advocated taking a long term average of the debt margin predicted by the CBASpectrum database. It claimed that the Essential Services Commission of South Australia (ESCOSA) adopted this approach in the recent distribution price review.[201]

H.7.2 The AER's considerations

Credit rating and gearing

In the SRP, the ACCC stated that it would not reference a TNSP's actual cost of debt because the actual cost of debt may not reflect efficient financing.[202] A WACC based on an industry-wide benchmark cost of debt may deter inefficient debt financing, because the revenue cap will contain only a return on capital allowance consistent with the benchmark return requirements, which should reflect efficient financing.

The cost of debt depends primarily on the credit rating of the debt issuer. As a general rule, debt attached with a lower credit rating has greater default risk and thus attracts a higher risk premium. The cost of debt should be determined by reference to a benchmark credit rating and the (market) debt margin associated with that rating. Adopting a benchmark credit rating for a TNSP, rather than an actual credit rating, provides flexibility for the TNSP to choose financing arrangements that best suit the business. It creates the incentive for the TNSP to manage cash flows, operations and gearing efficiently to minimise its perceived default risk and risk premium. This way, the TNSP can do better than the benchmark and gain from its efficiency.

Table H.4 sets out the long term credit rating assigned by Standard and Poor's for 18 Australian electricity and gas network companies.[203] It shows that the average credit rating of the electricity networks is A to A+, while the average credit rating of all entities, including gas networks, is A to A–.

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201 ESCOSA, *Electricity Distribution Price Review: Return on Assets—Preliminary Views*, Adelaide, January 2004, p. 71.

202 ACCC, *Statement of Principles*, op. cit., p. 109.

203 United Energy (now United Energy Distribution) and TXU Electricity (now SPI Electricity) are not included in the sample because they were recently acquired and undergoing restructuring, which would have an impact on their long term credit ratings. These firms may be included in the future.

Table H.4 Credit ratings of gas and electricity companies

Company	Long term rating	Actual gearing (%)
Ergon Energy	AA+	46.0
Country Energy	AA	67.8
EnergyAustralia	AA	52.5
Integral Energy	AA	54.7
SPI PowerNet	A+	76.8
Australian Gas Light	A	40.8
Citipower Trust	A–	54.1
ETSA Utilities	A–	64.1
Powercor Australia	A–	38.1
ElectraNet	BBB+	71.9
Aurora Energy	na	52.0
Energex	na	55.3
TransGrid	na	55.3
Western Power	na	62.5
Average electricity	A to A+	57.4
AlintaGas	BBB	61.9
Envestra	BBB	80.8
GasNet	BBB	69.8
Australian Pipeline Trust	na	66.4
Average all[204]	A to A–	60.2

Source: Standard and Poor's, *Australian Report Card Utilities*, March 2005.

The AER notes DJV's concern that in determining the relevant measure of gearing, the only proxy for the market value of government owned firms is the book value, which may not reflect prevailing market value. It concurs that this is a valid concern that could affect the comparability of gearing ratios.

DJV argued that only private companies should be considered in the sample. If the criteria of private and standalone companies were strictly observed, however, the sample would include only ElectraNet and the gas networks. Further, it could be argued that ElectraNet too should be excluded because the Queensland Government (through Powerlink) has a significant ownership interest.[205]

The AER deems it inappropriate to use only a sample of gas network companies to establish a benchmark credit rating for electricity TSNPs. The AER also includes gas network companies in the sample from which it monitors equity betas derived from

204 Assumes electricity and gas network companies with equal weighting.

205 ElectraNet's lower rating compared with other electricity networks may be related to its higher gearing.

market data. It is relevant when observing equity betas to include companies that operate in a line of business similar to electricity transmission where the systematic risk of the underlying capital is likely to be of similar magnitude.[206]

The AER considers that a sample of relevant Australian electricity transmission and distribution companies should be used as the primary basis for calculating a benchmark TNSP's credit rating, with minimal weight placed on gas network companies. This sample provides a range in which an average credit rating of A is considered to be conservative. The reasons for including distribution companies are that there are insufficient 'transmission only' entities with publicly available credit ratings to provide a reliable industry sample, and companies in the same industry are likely to exhibit similar risks profiles.

Nonetheless, the inclusion of distribution companies in the sample may provide a lower credit rating (that is, bias the sample towards TNSPs) because distribution is regulated by way of a price cap rather than a revenue cap (the latter of which is more likely to provide a stronger business profile). According to Fitch Ratings, while distribution operations typically involve a low business risk, similar to transmission operations:

> … they have more exposure to volume risk than transmission companies (e.g. volumes are sensitive to mild winters or summers).[207]

Further, in most Australian states other than South Australia and Victoria, the electricity distribution companies are bundled with retail operations. According to Standard and Poor's, electricity retailers operate in a highly competitive market and their credit quality will always be at the riskier end of the credit spectrum.[208] Fitch Ratings claim there would be only limited situations in which the existence of a retailing capacity would strengthen a distributor's standalone credit profile.[209] A transmission company is thus expected to have a stronger credit rating than that of other participants in the electricity industry.

In its sampling of the average credit rating for electricity network companies, the AER has included both private and government owned entities, as well as gas network companies as a secondary source of information. As mentioned, limiting the sample firms to standalone and private entities would not provide an appropriate sample to obtain a benchmark credit rating for the electricity network industry. The AER acknowledges that the inclusion of some government owned companies in the sample is likely to create an upward bias to the credit rating. Standard and Poor's has noted, for example, that the stronger AA credit rating is predominantly given to government owned utilities.[210]

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206 In this regard, the gas network companies represent the closest source of comparison to TNSPs because their systematic risk profile is likely to be similar.

207 Fitch Ratings, *Australian Electricity Sector—at that Awkward Adolescence Stage*, March 2004, p. 47.

208 Standard and Poor's, *Energy Australia and New Zealand*, op. cit., p. 9.

209 Fitch Ratings, op. cit., p. 47.

210 Standard and Poor's, *Australian and New Zealand Electric and Gas Utilities Ripe for Rationalization*, May 2002, p. 1.

Government/parent ownership is only one factor that may affect a credit rating. According to Standard and Poor's, the method used to rate power companies incorporates an assessment of both the financial and business risk characteristics of the entity. The financial risk assessment focuses on the ability of an entity to generate sufficient cash flows to service its debt, so involves consideration of the stability of an entity's revenue and gearing levels. The business risk assessment typically considers a broader range of issues that affect the key business or operating characteristics, such as:

- regulation
- markets
- operations
- competitiveness.[211]

By accounting for these additional factors, the AER is satisfied that the Standard and Poor's credit rating does not simply reflect the ownership structure but considers more broadly the stability of the entity's operations. Further, the potential upward bias from including government owned firms must be assessed against the likely downward bias from including distribution (bundled) firms. On balance, the AER's sampling, which includes the credit ratings of bundled distribution and government owned electricity network companies, is likely to provide a fair and reasonable credit rating for determining a benchmark TNSP. This conclusion is supported by statements by both Standard and Poor's and Fitch Ratings:

> … the 'A' rated entities are generally stable network or transmission businesses.[212]

> … the transmission company should enjoy stronger credit ratings than other players in the electricity chain, because of the strong regulatory environment and low operating risks currently evident in Australia.[213]

Conclusion

The AER considers its use of an average A credit rating for a benchmark TNSP is appropriate, and it will apply this rating in determining the debt margin for DJV. This conclusion is based on the statements of credit rating agencies and an assessment of a sample of Australian network companies. Such a credit rating is consistent with the overall environment in which Directlink operates and a gearing ratio of 60 per cent.

Term of the debt

Once a credit rating is established, a debt margin can be determined. The debt margin should reflect the prevailing market rates for debt issues reflecting the benchmark maturity and credit rating for the regulated entity. In previous revenue cap decisions, the ACCC has assumed a benchmark debt margin with a term equal to the regulatory period for the regulated entity. This position was consistent with the ACCC's use of a

[211] id., *Energy Australia and New Zealand*, p. 18.
[212] id., *Australian and New Zealand Electric and Gas Utilities Ripe for Rationalization*, p. 1.
[213] Fitch Ratings, op. cit., p. 40.

risk-free rate matching the regulatory period. As discussed in section H.2, however, the AER has adopted the 10 year bond rate as a proxy for the risk-free rate.

To maintain consistency between the two components of the cost of debt, the AER considers that the benchmark term of the relevant corporate bond rate should match the term of the risk-free rate being used. DJV has used the long term average of the CBASpectrum's predicted debt margin; ESCOSA used this approach in its most recent review. The CBASpectrum database provides a benchmark of expected fair corporate bond yields for a given maturity and credit rating. The CBASpectrum benchmark is calculated based on econometric estimation and predicts debt margins based, at times, on thin data.

Few bonds are issued with a tenor of 10 years in the Australian market, but the use of a benchmark debt margin does not assume that all of a TNSP's debt will be financed in this way. As stated by ESCOSA:

> The standard regulatory practice for deriving a benchmark cost of debt is to use Australian corporate bond yields to provide a proxy for borrowing costs, which reflects the fact that the use of traded bonds on the Australian market provides for a transparent method of deriving the cost of debt. However, the use of these yields does not imply an assumption that Australian utilities will finance all of their debt from this market. Rather, all that is required is that the yield on Australian corporate bonds provides an unbiased estimate of the cost of raising funds across the full range of funding sources available to Australian utilities. In addition, ESCOSA would not expect ETSA Utilities actually to raise all of its debt on one day from any of the potential funding sources, but rather would seek to raise debt when and where it was cheapest, subject to prudent risk management constraints.
>
> No evidence has been presented that the use of the yield on Australian corporate [bonds] systematically understates the cost of debt raising across the full range of funding options, either from ETSA Utilities or—to ESCOSA's knowledge—in other matters before another Australian energy regulator.[214]

Australian bond markets appear to generally prefer short term and higher rated debt. Options are available to highly geared TNSPs, such as credit wrapping and issuing for a shorter time period or in international markets, especially the United States, where the cost of finance may be lower. But there are difficulties in deriving an appropriate benchmark for such international financing.

Given that there is no evidence that the use of the yield on Australian corporate bonds systematically understates the cost of debt allowed in regulatory decisions, the AER will continue to reference the debt margin to Australian corporate bonds. DJV has adopted the long term averaging approach used by ESCOSA in its review, but ESCOSA's approach was undertaken in accordance with clause 7.2(c) of the Electricity Pricing Order, which requires the cost of capital to be calculated in accordance with the Reset Schedule, unless ETSA Utilities consents to depart from the schedule. The schedule specifies that the benchmark for calculating the risk-free rate should reflect the average yield over the past five years on a rolling average basis. While this approach primarily relates to the estimation of the risk-free rate, a similar approach is required for estimating the debt margin, to be internally consistent.

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214 ESCOSA, *Electricity Distribution Price Review: Return on Assets—Preliminary Views*, pp. 71–2.

In its review, ESCOSA noted that this is not standard practice among Australian regulators:

> The dominant practice is to derive the risk-free rate as a recent average (over, say, 10, 20 or 40 days) of bond yield, and not a long term average. The use of short term average reflects a consensus amongst finance experts that the interest rates currently available in the market provide the best forecast of future interest rates. A short period of averaging is used to minimuse the effects of any uniformed 'noise' that may be impounded into a single observation, but to be short enough to ensure that structural changes in interest rates are reflected in the new forecast.
>
> ESCOSA envisages using a recent average of the relevant bond yields (with a preference for 20 days) when next reviewing ETSA Utilities' price controls.

The AER considers that DJV's approach in this context appears unjustified. Consistent with the SRP, the AER proposes to calculate a short term average of the relevant bond yields. The 10 day moving average benchmark debt margin over the government bond yields, for A rated corporate bonds with a term of 10 years, is 84 basis points.[215] Consistent with calculating the risk-free rate, this has been adjusted to an effective annual compounding rate. Combined with the nominal risk-free rate of 5.50 per cent, it provides a nominal cost of debt of 6.34 per cent for use in the WACC estimate.

H.8 Value of franking credits

Australia has a full imputation tax system under which a proportion of the tax paid by a company is, in effect, personal tax withheld at the company level. The analysis of imputation (or franking) credits and their impact on the cost of capital in Australia is a developing field. The rate of use of tax credits or gamma (γ) may have an effect on the WACC (where a TNSP pays tax), and there is little doubt that franking credits have value:

> As the ultimate owners of government business enterprises, tax payers would value their equity (and post corporate tax cash flows) on exactly the same basis as they would value an investment in any other corporate tax paying entity. On this basis, it would be reasonable to assume the average franking credit value (of 50%) in the calculation of the network owner's pre-tax weighted average cost of capital.[216]

H.8.1 DJV's application

DJV has adopted the use of 0.5 for gamma. It acknowledges that a point in the range 0.30–0.50 for gamma is established in Australian regulatory decision making. Regarding empirical evidence, however, DJV commented that significant weight should be placed on the gamma estimates of Cannavan, Finn and Gray, which suggest that gamma should be 0.[217]

DJV argued that the Cannavan, Finn and Gray study gets around many problems that have plagued previous studies for the following reasons:

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215 Source: CBASpectrum <http://www.cbaspectrum.com>.

216 National Electricity Code, Schedule 6.1(5.2).

217 D Cannavan, F Finn and S Gray, 'The value of dividend imputation tax credits in Australia', *Journal of Financial Economics*, vol. 73, issue 1, 2004, pp. 167–9.

- The technique permits a larger sample of observations to be used, which has permitted estimates that have far greater precision (lower standard errors).

- The derivatives trade in advance of ex dividend dates, so there is less likelihood that the values estimated for franking credits will be affected by the actions of short term arbitrageurs around the ex dividend date.

- The study uses information that post dates the changes to the tax law discussed in the point above.

Further, DJV noted the ACCC's position that gamma should be estimated with a segmented market approach to the CAPM. It cited a submission to the ACCC by the National Economic Research Associates (NERA), which proposed using the international CAPM with parameters derived from domestic Australian observations. The submission claimed there is thought to be no bias in the estimated WACC, so long as the equity beta and MRP are both collected from the same market. DJV concluded that a gamma value of 0.5 is a conservative estimate and, more likely than not, overstates the value of imputation credits.

H.8.2 The AER's considerations

The gamma parameter incorporates dividend payouts carrying imputation credits and the proportion of those credits that could be used to offset tax payable on other income. In previous decisions, the ACCC has assumed a domestic CAPM, which values equity in the presence of franking credits. Given that the value of these credits is somewhere between 0 and 1 (no value and full value), the ACCC has consistently applied an average value for gamma of 0.5.

In considering the ratios of franking credits assigned to company tax paid for the eight largest listed companies in Australia, as studied by Associate Professor Lally, the result is a ratio of 1.[218] Given that these companies constitute 50 per cent of total equity listed in Australia, Lally suggested that this ratio is close to 1 for most industries. It is thus apparent that franking credits have some value. The proportion that investors can use to offset tax payable on other income is ambiguous, however. In the past, the estimate of the average value once distributed has ranged from 50 per cent to 90 per cent.

The AER notes DJV's reference to the NERA submission forming TransGrid's revenue cap application to the ACCC. NERA claimed that the application of the domestic CAPM, in the absence of market integration having a recent, substantial effect on required investor returns, would provide a good estimate of the result that would be obtained from a more complex international CAPM model.[219] The NERA submission did not advocate mixing and matching parameters from segmented and integrated markets; rather, it suggested that there should be little difference between the WACCs calculated with the domestic CAPM and an international CAPM.

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[218] Lally, op. cit., p. 19.

[219] NERA, *International Versus Domestic CAPM*, *Attachment 16 of TransGrid 2004 Revenue Reset Application*, 2003, p. 9.

The ACCC had previously addressed this claim in its TransGrid draft decision and noted concerns with the use of domestic parameters in an international CAPM:

> The alternative approach of assuming foreign ownership and using an international CAPM may be methodologically sound, but in practice it would be less feasible given the difficulty of assessing corresponding WACC parameters.
>
> According to finance theory, in a fully integrated financial market, there would be no barriers to financial flows and purchasing power parity would hold across equivalent assets wherever they are traded. Because markets are integrated, the use of an international CAPM would assume that all investors are fully diversified across asset classes. The risky assets are placed in the world market portfolio and this optimal world market portfolio is shared by investors in every country.
>
> The world market portfolio is a diversified set of international assets (such as shares, bonds, bills, derivatives, and real estate). The systematic risk of an asset in an integrated financial market reflects the asset's sensitivity to changes in the value of the world market portfolio.
>
> On this basis, the ACCC considers that when comparing the use of a domestic CAPM with an international CAPM, there would be some source of difference in the parameters. That is, when using the international CAPM, the MRP and beta risk should reflect the global rather than a national market portfolio.[220]

Having established that using an international CAPM requires corresponding 'international' parameters, the ACCC cited complexities with using the international CAPM:

> … the domestic MRP currently used would require adjustment to reflect the global MRP. The process of estimating a global MRP also raises questions of the use of historical estimates and what time period data should be considered to reliably estimate the global MRP.[221]
>
> In this context, the use of an international CAPM tends to be more complex and consequently more difficult to implement. This may explain why they are not generally used in practice, despite the accumulating evidence of greater market integration.

For these reasons, the ACCC concluded that using the domestic parameters would require maintaining the application of the domestic CAPM.

This was also a central theme in the study by Lally, which stated that consistency is required. The study compared the cost of capital calculated under international and domestic models.[222] The result was a slightly higher cost of capital associated with using the domestic model. The alternative approach of assuming foreign ownership and using an international CAPM may be methodologically sound, but would be less feasible given the difficulty of assessing corresponding WACC parameters. Lally noted that use of an international value of gamma within the domestic CAPM inflated the cost of capital above the result obtained using the full international or full domestic models.

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220 ACCC, TransGrid 2004–2009 revenue cap., p. 75–6.

221 Lally suggested that estimates of the international MRP should follow the Stulz-Merton method. In this instance, a world MRP of 3.9 per cent has been estimated, consistent with expanded international investment opportunities where a lower MRP is due to the increased diversification implicit in a world market portfolio.

222 Lally, op. cit., pp. 15–16.

Accordingly, the AER does not consider that a conceptual analysis simplifies the estimation of the value attributable to franking credits. Rather, it considers that it is appropriate to place most weight on the empirical evidence of the value of franking credits. The AER acknowledges that the Cannavan, Finn and Gray study observed a larger sample of trades and accounted for the most recent information that post dates the ex dividend tax law changes. That study should be considered, however, in the context of all studies (based on other methods of analysis, such as dividend drop-offs) that have estimated a value of gamma.

All estimation techniques have their own shortcomings. While the Cannavan, Finn and Gray study included a large number of trades, it included only a limited number of companies, all of which were very large and had very large foreign shareholdings. While TNSPs may exhibit characteristics similar to those of the sample companies, the limited number of companies in the sample may affect the study's applicability to the Australian share market.

The use of individual share futures to value franking credits is likely to be sensitive to the option pricing formula assumed. Further, the values yielded by individual share futures may not reflect the value that long term TNSP investors ascribe to franking credits. In contrast, dividend drop-off studies, which have been the dominant method for estimating the effects of investor taxation on market valuations, provided results that reflect the effects of dividend imputation across all listed companies. This technique, however, has limitations too.

The measurement of the value of franking credits is subject to substantial measurement error. Theoretical issues have been debated in previous regulators' considerations, such as whether the proportion of foreign investment in the market should imply that the marginal value of franking credits should be assumed to be 0. Other studies, such as the Hathaway and Officer paper, suggest that assuming a 0 value for imputation credits would be a gross error.[223] Further, Lally concluded that a gamma of 1 is appropriate for Australian regulatory decisions.

Given the inconclusive nature of the empirical evidence, the AER considers that the selection of gamma is a matter of judgment. A commonsense approach suggests that franking credits have some value and this affects company values. Such a conclusion is consistent with recent compamy restructurings that have been onserved in the market. Further, there does not seem to be consensus among Australian academics and finance practitioners on adjusting the rate of use of franking credits. Australian regulators have almost uniformly adopted the assumption that franking credits created are valued at approximately half their face value. Given that the AER applies a domestic CAPM, a change to the value for gamma is not appropriate at this time. Accordingly, the AER will continue using the value of 0.5 for gamma.

H.9 Debt and equity raising costs

Debt raising costs

To raise debt, a company has to pay debt financing costs beyond the debt margin. Such costs are likely to vary between each debt issue, depending on the borrower,

223 Neville Hathaway and Bob Officer, *The Value of Imputation Tax Credits*, *Update*, 2004, p. 26.

lender and market conditions. The ACCC recently commissioned the ACG to consider the appropriateness of allowing transaction costs associated with debt and equity financing, and to determine a benchmark allowance for these costs.[224] According to the ACG, the debt raising cost being considered should be the transaction cost of refinancing fixed rate bonds to the value of the notional gearing component of the TNSP's RAB (assuming a consistent benchmark credit rating). The allowed debt benchmark does not relate to:

- acquisitions by the regulated firm
- non-core construction or investment activities being undertaken.

The transaction costs associated with the benchmark cost of debt should not, therefore, relate to activities outside the refinancing of bonds for the regulated firm's core activities.[225]

Equity raising costs

An entity pays equity raising costs when it raises capital. The cost of initial public offerings (floats) can be used as a proxy for transaction costs of raising equity. The structure of fees in a typical float includes:

- management
- underwriting
- selling
- legal and accounting
- consulting
- other out-of-pocket fees.[226]

For initial equity raising costs, fundamental questions are whether the RAB has already been determined and, in the case of privately owned utilities, whether a RAB was established before privatisation. For utilities, costs for raising subsequent equity capital have generally been for acquisition activity outside the regulated business. In most situations, the need for access to external equity funds would not be expected to arise if the entity financed in a manner consistent with the regulatory benchmarks.

H.9.1 DJV's application

DJV stated that substantial costs are incurred in raising and re-raising both debt and equity finance, which the revenue caps for TNSPs should reflect. It has proposed allowing 25 basis points on the regulatory debt value to account for debt raising costs. This has already been included in the forecast operating expenses for Directlink.

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224 ACG, *Debt and Equity Raising Transaction Costs—Report to the ACCC*, December 2004.
225 ibid., p. 5.
226 ibid, pp. 56–7.

DJV also proposed allowing 21.2 basis points per year on the regulatory equity value to account for equity raising costs. This has been included in the forecast operating and maintenance expenditure (opex) for Directlink.

H.9.2 The AER's considerations

Debt raising costs

TNSPs should be provided a benchmark allowance for debt raising costs that reflects current market costs. A recent consultancy by the ACG concluded that debt raising costs are a legitimate expense that should be recovered through the revenues of the regulated utility.[227] Given that transaction costs associated with debt would continue to be incurred for the whole value of the investment, the ACG considered that the most appropriate means of recovering these costs would either be as an addition to the estimated WACC or as a direct allowance to opex.

The ACG based its benchmark on debt raising costs applicable to Australian international bond issues or joint Australian market/international issues. In developing the benchmark, it calculated a gross underwriting fee benchmark of 5.5 basis points per year, based on a five year term. To this, it added allowances for legal and roadshow expenses; credit rating fees for the firm and for each issue of bonds; and registry and paying charges. Table H.5 shows the build-up of debt raising costs and the total recommended benchmark for bond issues.

Table H.5 Benchmark debt raising costs for bond issues

Fee	Explanation/source	One issue	Two issues	Four issues	Six issues
Amount raised	Multiples of median bond issue size	\$175 m	\$350 m	\$700 m	\$1 050 m
Gross underwriting fees	Bloomberg for Australian International issues, tenor adjusted	5.5	5.5	5.5	5.5
Legal and roadshow	\$75 000–100 000: industry sources	1.1	1.1	1.1	1.1
Company credit rating	\$30 000–50 000: Standard and Poor's ratings	2.9	1.4	0.7	0.5
Issue credit rating	3.5 (2–5) basis points upfront: Standard and Poor's ratings	0.7	0.7	0.7	0.7
Registry fees	\$3000 per issue: Osborne Associates	0.2	0.2	0.2	0.2
Paying fees	\$1 per \$1 million quarterly: Osborne Associates	0.0	0.0	0.0	0.0
Total	Basis points per year	10.4	9.0	8.2	8.0

Source: ACG, *Debt and Equity Raising Costs—Report to the ACCC*, 2004, p. xviii.

227 ibid., p. xiii.

Based on the evidence provided by the ACG, the AER considers it is appropriate to allow benchmark debt raising costs derived in accordance with the above table. DJV has an opening RAB of $116.68 million, and the assumed benchmark gearing ratio is 60:40. The notional debt component of the RAB is thus around $70 million ($116.68 million × 0.6).

According to table H.5, the overall debt size of this amount would require one issue. An allowance of 10.4 basis points per year for debt raising costs is thus a reasonable benchmark for DJV. This benchmark is multiplied by the debt component of the RAB to provide an average allowance of about $0.06 million per year over the regulatory period. This is included as part of opex (chapter 12) because it is an identified cost category.

Equity raising costs

In previous regulatory decisions, the ACCC provided a benchmark allowance for equity raising costs. More recently, in the Transend revenue cap decision, it did not provide an allowance for equity raising costs, on the basis that the TNSP would be unlikely to incur equity raising costs during the regulatory period. The ACCC also did not provide equity raising cost in the TransGrid revenue cap decision.

The recent ACG consultancy for the ACCC considered the legitimacy of recovering equity raising costs and the benchmark value for such costs incurred by an entity through initial public offerings (IPO) and seasoned equity offerings. The ACG determined that if the RAB for a regulated entity has already been established, then it is not appropriate to include an allowance for the cost of raising equity.[228] But where new standalone assets are built and a RAB is yet to be established, the opening regulated asset value should reflect all costs, including a benchmark allowance for the cost of raising equity (subject to how the assets are financed).[229]

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228 ibid., pp. xi–xii.
229 ibid., pp. 54–5.

Table H.6 Benchmark equity raising costs for IPOs

Company	Date of offer	Details of offer	Raising costs ($m)	Total offer ($m)	Fees as % of total offer
United Energy	March 1998	IPO—stapled securities	20.0	968.2	2.10
Envestra	July 1999	Rights, convertible notes placement	10.1	310.0	3.26
Australian Pipeline Trust	May 2000	IPO—units	12.0	488.00	2.50
GasNet	October 2001	IPO—units	15.0	260.2	5.77
Macquarie Communications Infrastructure Group	July 2002	IPO—stapled securities	13.0	310.0	4.20
Prime Infrastructure	2002	IPO—units	11.4	284.5	4.00
DUET	August 2004	IPO—stapled units	9.4	257.9	3.6
Mean			13.5	428.1	3.69
Median			12.5	297.3	3.83
Hastings Diversified Utilities Fund	November 2004	IPO—stapled units	12.5	378.9	3.30
New mean			13.3	421.1	3.64
New median			12.5	310.0	3.64

Source: ACG, *Debt and Equity Raising Costs—Report to the ACCC*, 2004, p. 60.

If equity raising costs are allowed, the ACG recommended the use of IPO costs as a proxy for equity raising costs. It proposed a benchmark based on the median IPO transaction cost measured across a sample of seven infrastructure capital raisings. It found that utility floats can be expected to have a lower transaction cost due to their stable and regulated cash flow streams. The ACG also recommended treating the cost of raising equity as part of the optimised replacement cost value and depreciating it (along with other assets) to the depreciated optimised replacement cost value.[230]

Table H.6 illustrates the ACG's analysis of equity raising costs for IPOs. In addition, the AER has updated the analysis to include the recent IPO for Hastings Diversified Utilities Fund, which brings the new median benchmark to 3.64 per cent.

In financing subsequent capital expenditure, the ACG found that firms finance the equity share of their subsequent capital expenditure in the least cost manner. This implies financing from retained earnings where possible and debt financing in preference to equity financing.

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[230] ibid., p. x.

Based on ACG's findings, the AER considers that benchmark equity raising costs should be allowed for DJV because DJV's RAB is being established for the first time. That is, this draft decision sets the opening RAB for DJV if Directlink converts from a market network service to a prescribed service. The RAB provides for a benchmark of 3.64 per cent (that is, $1.9 million) allowance for equity transaction costs. Section 11.4.2 discusses the inclusion of this benchmark equity raising cost in the RAB.

H.10 Treatment of taxation

In its early regulatory decisions, the ACCC applied the statutory company tax rate of 30 per cent. This was done in the context of difficulties in determining an accurate long term tax rate as part of the pre-tax real framework being used at the time. The capital intensive nature of electricity utilities, however, has historically meant that the effective tax rate for such networks has been less than the statutory tax rate.[231]

H.10.1 DJV's application

DJV has applied the standard statutory tax rate of 30 per cent.

H.10.2 The AER's considerations

In recent decisions, the ACCC has applied an effective tax rate, derived from the standard statutory tax rate. The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to a number of factors, which include the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Although the tax rate on accounting income is always at the corporate tax rate, in any year the income assessable for tax purposes can be quite different from the net revenues available to the business.

The timing aspect and the fact that taxes are assessed on the basis of nominal income mean that the prevailing inflation rate also has a significant impact on the effective tax rate. The effect of tax deferral on the timing of cash flows does not generally cause administrative difficulties for a corporate entity that is accustomed to uneven cash flows.

The capital intensive nature of electricity utilities has historically meant that the effective tax rate for such networks has been less than the statutory tax rate. The AER considers that a post-tax nominal framework that uses that effective tax rate can generate more appropriate and cost-reflective revenue cap outcomes. Based on this approach to modelling the effective tax rate, the AER has derived an effective tax rate of 18.74 per cent.

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231 According to IPART calculations, the average effective tax rate paid by the NSW distributors amounted to 25 per cent in 1996–97: IPART, *The Rate of Return of Electricity Distribution Network—Discussion Paper*, Sydney, November 1998, p. 9.

Appendix I Service standards

This appendix sets out the AER's consideration of DJV's service standards performance incentive scheme for the 2005–06 to 2014–15 regulatory period as follows:

- DJV's application (section I.1)
- submissions and the consultancy report (section I.2)
- the AER's considerations (section I.3)
- the conclusion (section I.4).

I.1 DJV's application

I.1.1 Performance measures

DJV proposed that the performance measure of circuit availability captures all of Directlink's appropriate service attributes. It stated that circuit availability is a standard measure of performance that is widely used for high voltage direct current (HVDC) facilities such as Directlink. DJV defined the circuit as 'available' when at least one of its three units is available. Subsequent to receiving the Parsons Brinckerhoff Associates' (PB Associates) report (see below), DJV revised its proposal to be consistent with the definition from the International Council on Large Electric Systems, known as the CIGRE protocol.

For measuring circuit availability, DJV proposed the peak period to be between 7 am and 10 pm on week days, excluding public holidays in New South Wales (NSW) or Queensland. This definition accounts for Queensland public holidays that do not fall in NSW: Labour Day in Queensland (the first Monday in May) is the only day that fits this category.

I.1.2 Performance targets

DJV asked its consultant, Ballengearry Consulting, to assess the future performance expected of Directlink. The figures in DJV's submission depend on the remedial actions proposed by Ballengearry Consulting to improve the reliability of the Directlink facility. DJV has not expressly sought funding for these projects in its revenue cap application. It has based its performance target figures on expected performance, given past reliability concerns and because Directlink has not been a regulated asset in the past.

DJV has proposed planned outages of 48 hours per year. This figure represents a higher planned availability than Murraylink, which has 72 hours of planned outage. For both peak and off-peak forced outages, DJV has proposed 67.11 hours (compared with Murraylink, which has 100.8 hours of forced outages).

I.1.3 Excluded events

In measuring availability, DJV has argued that it should not be penalised under the performance incentive scheme for certain events. These events are referred to as excluded events. DJV proposed the following definition of an excluded event:

1. a fault, other event or capacity constraint on a third party system (e.g. intertrip signal, general outage, reaching a thermal power flow or voltage limit, failure of SCADA or other communication system)

2. an instruction or direction from an authority

3. disconnection, interruption or works by Country Energy, TransGrid or Powerlink Queensland

4. damage to the circuit's cables or equipment from action by a third party that, in the opinion of the AER, DJV's best endeavours were unable to prevent

5. force majeure events.

Further to the force majeure definition in the service standards guidelines, DJV has proposed the following additional clauses in the definition for force majeure:

- the loss or damage to, 11 or more control or secondary cables

- the loss or damage to, two or more transformers and capacitor banks, either single or three phase, connected to a bus

- the loss or damage to, a transformer, capacitor bank or reactor, which loss or damage is not repairable on site according to normal practices.

I.1.4 Financial incentives

DJV has proposed that 1 per cent of the allowed revenue (AR) be placed at risk, as an incentive to meet benchmarked performance in terms of planned outages and forced availability in peak and off-peak periods. It has also proposed that the performance incentive scheme should be reviewed five years after the determination takes effect.

I.2 Submissions and the consultancy report

I.2.1 Performance measures

In its report, PB Associates agreed with DJV that circuit availability is the only relevant performance measure because it is an interregional transmission link. Further, PB Associates advised that the Directlink circuit should be considered a single circuit in the calculation of availability, despite consisting of three parallel links. This reasoning is consistent with the CIGRE protocol.

PB Associates recommended that the performance measure of circuit availability be broken into three categories: planned outages, peak forced outages and off-peak forced outages. It found that any performance measures should be evaluated not only when the whole Directlink facility is out of service, but also when one or more of the individual lines are out of service. It proposed defining peak period to be from 7 am to 10 pm Eastern Standard Time on working week days in NSW, and explicitly including the Labour Day public holiday in Queensland in the definition. In response to PB Associates' recommendation, DJV maintained its proposal that the definition of peak period should not include days where a public holiday falls in Queensland and/or NSW.

I.2.2 Performance targets

PB Associates considered that the targets proposed by DJV represent sufficient availability performance levels to reliably provide the network support services claimed in DJV's application.

I.2.3 Excluded events

PB Associates stated that the specific exclusions and additions to the force majeure definitions proposed by DJV are inappropriate, and that DJV should have to satisfy such exclusions to the AER on a case-by-case basis. This approach would be consistent with requirements under the annual compliance reporting framework of the service standards guidelines. In response to PB Associates' report, DJV argued that its excluded events and force majeure provisions are both reasonable and consistent with the service standards guidelines and previous ACCC revenue cap decisions.

I.2.4 Financial incentives

PB Associates considered that capping the penalty provision at 1 per cent may provide an inadequate incentive 'given the history of technical issues and high unavailability of the Directlink asset operating as an MNSP [market network service provider] in the NEM [National Electricity Market]'.[232] DJV generally agreed with PB Associates, but disagreed that:

- the cap on the financial incentive should be greater than 1 per cent of the AR
- 100 per cent availability should be required for the maximum financial reward
- a collar should be established around Directlink's performance target levels.

DJV explained the history of the technical issues outlined by PB Associates. It contended that the proposed performance incentive scheme provides a sufficient incentive to meet the target of 99 per cent availability. The Energy Users Association of Australia, however, submitted that the amount of Directlink's revenue placed at risk under the incentive scheme does not provide an adequate financial incentive to Directlink. It noted that a firm in a competitive environment must constantly improve performance just to maintain its market position, and that incentive regulation must mimic the competitive discipline of a non-regulated market.

The Energy Retailers Association of Australia stated that:

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232 PB Associates, *Review of Directlink Conversion Application*, op. cit., p. 75.

- transmission network service providers (TNSPs) should have the incentive to provide transfer capacity when required
- TNSPs should not be penalised for not providing transfer capacity when it is not required
- any incentive should be proportional to the value of the service being provided.

The association recognised that Directlink, as a point-to-point link, avoids many of the complexities that can arise when applying the above service standards to meshed networks. It also considered that the present situation provides a unique opportunity to develop a superior service standards regime and thereby enhance the value of Directlink to network users.

I.3 The AER's considerations

For setting DJV's revenue cap, the AER proposes to apply the performance incentive scheme outlined in the service standards guidelines, subject to the following considerations.

I.3.1 Performance measures

DJV has proposed a service standard measure of circuit availability linked to a financial incentive. This is an appropriate measure because it provides an incentive to maximise the amount of time and capacity that the asset is available.

In determining the market benefits (see section 7.4.2), the AER assumed a reliability of at least 99 per cent for 120 MW transfer capability. However, for the avoidance of doubt, in measuring the actual availability of Directlink and for the purpose of the service standards incentive scheme, all three circuits or 180 MW should be included in the performance targets. The AER considers that this is consistent with PB Associates' recommendation and the CIGRE protocol which measures availability in terms of capacity unavailable and the duration this unavailability to determine energy unavailability.

For measuring circuit availability, the AER reviewed historical peak demand. Table I.1 shows that the Queensland Labour Day public holiday in the past two years has exhibited peak loads in NSW relative to the average peak loads for April and May. Assuming that a peak day in NSW is likely to require energy to be imported from Queensland, peak loads require south flows across Directlink. The Queensland Labour Day should thus be treated as a peak day for Directlink's performance reporting.

Table I.1 Peak demand data for Queensland and NSW during April and May

Year	Average demand during the peak period for April–May (megawatts)[233]		Average demand during the peak period for the first Monday in May (megawatts)	
	Queensland	NSW	Queensland	NSW
2005	6211	9369	5523	9200
2004	6024	9057	5868	9210

I.3.2 Performance targets

Directlink has been operating as an unregulated interconnector. As such, its incentives to be available for service have related to its expected income and thus price divergence between NSW and Queensland, rather than the provision of network service at times when of value to network reliability and security. Further, Directlink experienced some technical problems in its early years of service, which DJV intends to resolve over the coming years. The AER considers, therefore, that it would be inappropriate to use Directlink's historical performance to determine its future performance targets.

DJV's proposed performance targets are based on planned and other outages, and are higher than those set in the decision on Murraylink (an interconnector similar to Directlink). PB Associates reviewed DJV's proposed performance targets and found them to be reasonable. It recommended that the AER adopt the proposed targets. Given PB Associates' recommendation and the comparison with Murraylink's targets, the AER considers DJV's proposed targets to be appropriate.

I.3.3 Excluded events

The provision of exclusions and a force majeure clause is designed to prevent a TNSP from being penalised for the impact of events over which it has no control. It is not intended to be an inclusive list of events that cause unavailability. This is important because it maintains incentives for TNSPs to take necessary steps to maximise asset availability and thus the regulated service to customers.

Schedule 1 of the service standards guidelines outlines the exclusions for the measure of transmission circuit availability as:

- unregulated transmission assets
- any outages shown to be caused by a fault or other event on a 'third party system'—for example, intertrip signal, generator outage or customer installation (TNSP to provide list)
- force majeure events.[234]

233 Peak period being Monday to Friday 7 am to 10 pm.

To the extent that the service standards guidelines provide appropriate exclusions, there is benefit in maintaining the defined words for transparency and consistency in the treatment of exclusions for other TNSPs. Table I.2 sets out DJV's proposed exclusions and the AER's consideration of whether the service standards guidelines allow similar exclusions that provide adequate coverage to DJV's proposed excluded events.

Table I.2 DJV's proposed exclusions and those in the service standards guidelines

DJV's proposed exclusions	Covered by service standards guidelines	
1. A fault, other event or capacity constraint on a third party system (for example, intertrip signal, general outage, reaching a thermal power flow or voltage limit, failure of SCADA or other communication system)	Schedule 1	Any outages shown to be caused by a fault or other event on a 'third party system'—for example, intertrip signal, generator outage, customer installation (TNSP to provide list)
2. An instruction or direction from an authority	Schedule 1 Schedule 2	Force majeure events Action or inaction by a court, government agency (including denial, refusal or failure to grant any authorisation, despite timely best endeavour to obtain same)
3. Disconnection, interruption or works by Country Energy, TransGrid, or Powerlink Queensland	Schedule 1	Any outages shown to be caused by a fault or other event on a 'third party system'—for example, intertrip signal, generator outage, customer installation (TNSP to provide list)
4. Damage to the circuit's cables or equipment from action by a third party that, in the opinion of the AER, DJV's best endeavours were unable to prevent	Schedule 1 Schedule 2	Force majeure events Any event, act or circumstance or combination of events, acts and circumstances which (despite the observance of good electricity industry practice) is beyond the reasonable control of the party affected by any such event
5. Force majeure events	Schedule 1	Force majeure events

In relation to DJV's proposed exclusion 2, it is reasonable (to avoid doubt) to insert 'NEMMCO' into the force majeure definition.

DJV's proposed additions to the definition of force majeure mean those events would be excluded per se. Those events should still be explained on a case-by-case basis, however, and thus not excluded per se. This will maintain incentives for the TNSP to take necessary steps to maximise its asset availability and thus the regulated service to customers. To avoid doubt, the words proposed by DJV have been amended and inserted into the definition of force majeure.

[234] AER, *Compendium of Electricity Transmission Regulatory Guidelines*, op. cit., p. 45.

I.3.4 Included events

DJV's application does not propose definitions for included events. The service standard guidelines, however, define inclusions for the purposes of the availability measure:

> 'Circuits' includes overhead lines, underground cables, power transformers, phase shifting transformers, static var compensators, capacitor banks, and any other primary transmission equipment essential for the successful operation of the transmission system (TNSP to provide lists).
>
> Circuit 'unavailability' to include outages from all causes including planned, forced and emergency events, including extreme events.[235]

To avoid any doubt and maintain consistency with the service standards guidelines, the standard definitions for included events should be incorporated.

I.3.5 Financial incentives

The service standards guidelines state that 1 per cent of the AR should be used as a financial incentive, because the performance incentive scheme is in the early stage of its development. Some interested parties argued that placing 1 per cent of AR at risk would provide insufficient incentive to DJV to perform at high levels.

The AER is establishing Directlink's first performance incentive scheme as a regulated interconnector. There is some uncertainty about the appropriate service standards, and significant risks remain in the case where the performance targets have not been accurately measured. Consequently, implementing a large financial incentive would most likely lead to windfall gains or losses.

Accordingly, it is appropriate to maintain consistency with the service standards guidelines by setting a financial incentive of 1 per cent of the AR. This approach will minimise exposure of the TNSP and customers to excessive risk and uncertainty. Starting with a small financial incentive will also allow the AER to monitor the performance incentive scheme, gather performance information and set improved targets in following reviews. It will also provide some incentive to DJV to meet performance targets.

I.3.6 Review of the scheme

DJV has proposed a review of the performance incentive scheme after five years. Given the regulatory period is set for 10 years, the AER agrees that reviewing the performance incentive scheme after five years would be appropriate. The review would also help the AER gather performance information on Directlink and allow an assessment of the scheme.

While the AER may review DJV's service standards after five years, its power to re-open a revenue cap within a regulatory period is limited to the events set out under clause 6.2.4(d) of the National Electricity Code (now the National Electricity Rules).

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[235] ibid., p. 45.

Unless the National Electricity Rules are amended (and the amendment applies to DJV's revenue cap), the findings of the review may not be implemented until the following regulatory period.

I.4 Conclusion

The service standards performance incentive scheme to apply to DJV's revenue cap for the 2005–06 to 2014–15 regulatory period consists of the following components:

1. The applicable performance measure is 'circuit availability', which comprises three submeasures: scheduled, peak forced and off-peak forced. These measures are defined in table I.3.

2. Clause 6.2.5 of the National Electricity Rules and the service standards guidelines require DJV to provide an annual report to the AER on DJV's performance against the measures. Experience indicates that the report should be provided by the end of January each year for the preceding calendar year, to enable DJV to determine its maximum allowed revenue (MAR) for the following financial year.

3. The MAR for a financial year (*t*) includes an amount (which may be positive or negative) (the 'financial incentive') based on DJV's performance against the measures for the preceding calendar year. The building block formula is set out in chapter 14 of this draft decision. In summary:

$$\mathrm{MAR}_t = \left(\mathrm{AR}_t\right) \pm \left(\frac{\left(AR_{t-2} + AR_{t-2}\right)}{2} \times S_{ct}\right) \pm \text{(pass-through)}$$

where:

MAR	=	the maximum allowed revenue
AR	=	the allowed revenue
S	=	the service standards factor
t	=	the time period/financial year
ct	=	the time period/calendar year.

Tables I.4, I.5 and I.6 determine 'S' for each of the three prescribed performance submeasures, depending on DJV's performance. Table I.7 sets out the weight to apply to each submeasure to calculate the S factor. The scheme allows 48 hours for scheduled outages, 28.96 hours for peak forced outages and 38.15 hours for off-peak forced outages. Availability above or below these levels will result in DJV receiving a bonus or a penalty respectively. In total, 1 per cent of DJV's AR is placed at risk.

Table I.3 Definition of circuit availability

<table>
<tr><td>Sub measures</td><td>Scheduled availability
Forced peak availability
Forced off-peak availability</td></tr>
<tr><td>Unit of measure</td><td>Percentage of total possible hours (capacity weighted) available.</td></tr>
<tr><td>Source of data</td><td>Directlink outage register and disturbance and outage report
Peak time from 7.00 am to 10.00 pm weekdays (excluding public holidays in NSW)
Off–peak all other times</td></tr>
<tr><td>Formula</td><td>Formula:
$100\% - \left(\frac{\text{Hours of total capacity unavailable per year}}{\text{Total possible no. of defined circuit hours per year}} \right) \times 100$</td></tr>
<tr><td>Exclusions</td><td>Exclude unregulated transmission assets.
Exclude from ‘circuit unavailability’ any outages shown to be caused by a fault or other event on a ‘third party system’—for example, intertrip signal, generator outage, customer installation (TNSP to provide list).
Exclude force majeure events (defined below).</td></tr>
<tr><td>Inclusions</td><td>‘Circuits’ include overhead lines, underground cables, power transformers, phase shifting transformers, static var compensators, capacitor banks and any other primary transmission equipment essential for the successful operation of the transmission system.
Circuit ‘unavailability’ to include outages from all causes, including planned, forced and emergency events, including extreme events.</td></tr>
<tr><td>Definition of force majeure</td><td>(a) ‘Force majeure events’ means any event, act or circumstance or combination of events, acts and circumstances that (despite the observance of good electricity industry practice) is beyond the reasonable control of the party affected by any such event, which may include, without limitation, the following:
(i) fire, lightning, explosion, flood, earthquake, storm, cyclone, action of the elements, riots, civil commotion, malicious damage, natural disaster, sabotage, act of a public enemy, act of God, war (declared or undeclared), blockage, revolution, radioactive contamination, toxic or dangerous chemical contamination or force of nature
(ii) action or inaction by a court, NEMMCO or government agency (including denial, refusal or failure to grant any authorisation, despite timely best endeavour to obtain same)
(iii) strikes, lockouts, industrial and/or labour disputes and/or difficulties, work bans, blockades or picketing
(iv) acts or omissions (other than a failure to pay money) of a party other than DJV which party either is connected to or uses the high voltage grid or is directly connected to or uses a system for the supply of electricity which in turn is connected to the high voltage grid
where those acts or omissions affect the ability of DJV to perform its obligations under the service standard by virtue of that direct or indirect connection to, or use of, the high voltage grid.
(b) To avoid doubt, the following may be ‘force majeure events’ depending on the circumstances at the time:
(i) the loss of, or damage to, 11 or more control or secondary cables
(ii) the loss of, or damage to, two or more transformers and capacitor banks, either single or three phase, connected to a bus
(iii) the loss of, or damage to, a transformer, capacitor bank or reactor where the loss or damage is not repairable on site according to normal practice.
(c) Words appearing in italics have the meaning assigned to them from time to time by the National Electricity Rules.</td></tr>
</table>

The following tables and figures represent the scale of the penalty and reward. Tables I.4–I.6 show the set of linear equations that are represented in figures I.1–I.3. The S factor (y axis) is the percentage of the AR that will be calculated depending on the actual availability (x axis) for each measure.

Table I.4 Scheduled circuit availability

							Where:				
S1	=	–0.003							Availability	<	98.9
S1	=	0.005454545	x	Availability	–	0.542454545	98.9	≤	Availability	≤	99.45
S1	=	0.005454545	x	Availability	–	0.542454545	99.45	≤	Availability	≤	100
S1	=	0.003					100	<	Availability		

Figure I.1 Scheduled circuit availability

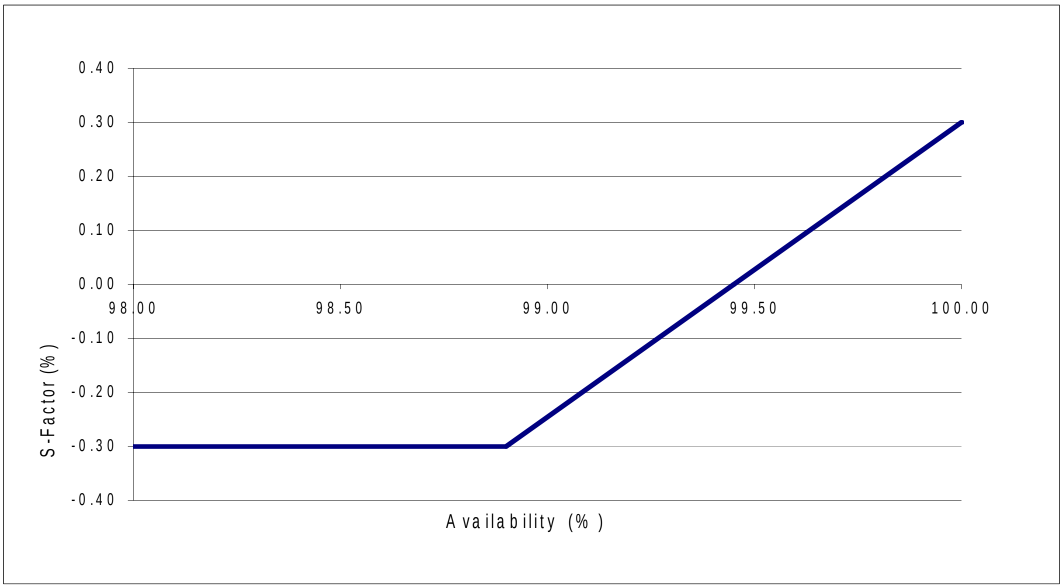

Table I.5 Forced peak circuit availability

							Where:				
S2	=	–0.0035							Availability	<	98.47
S2	=	0.004605263	x	Availability	–	0.456980263	98.47	≤	Availability	≤	99.23
S2	=	0.004545455	x	Availability	–	0.451045455	99.23	≤	Availability	≤	100
S2	=	0.0035					100	<	Availability		

Figure I.2 Forced peak circuit availability

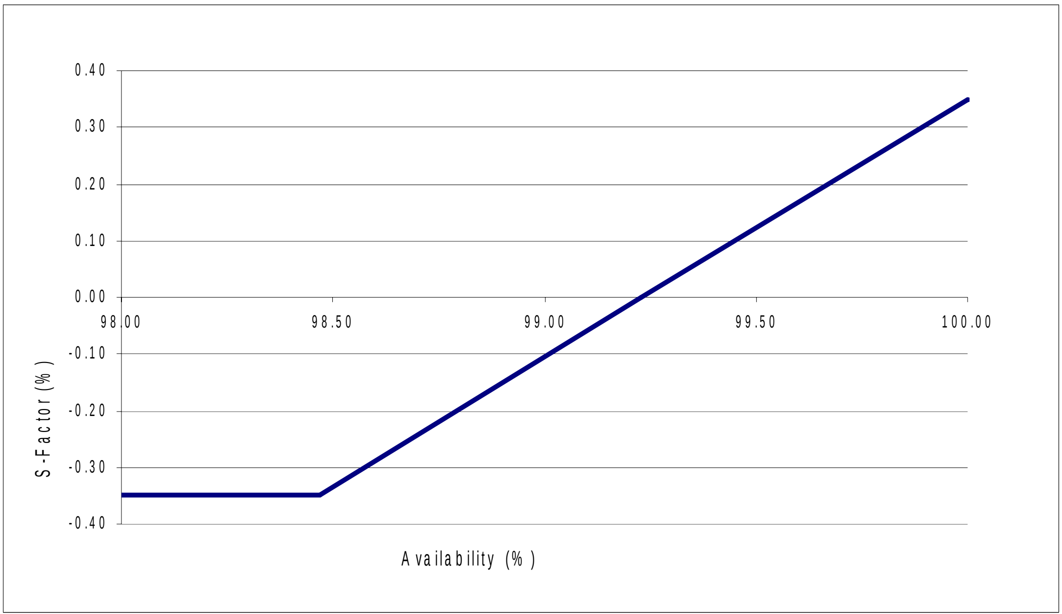

Table I.6 Forced off-peak circuit availability

							Where:				
S3	=	–0.0035							Availability	<	98.47
S3	=	0.004605263	x	Availability	–	0.456980263	98.47	≤	Availability	≤	99.23
S3	=	0.004545455	x	Availability	–	0.451045455	99.23	≤	Availability	≤	100
S3	=	0.0035					100	<	Availability		

Figure I.3 Forced off-peak circuit availability

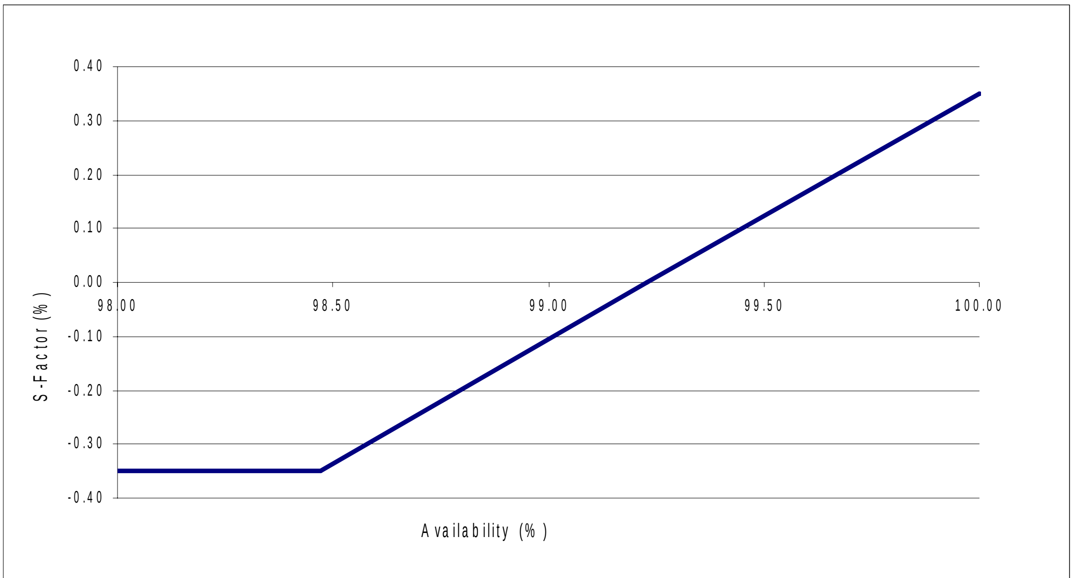

Table I.7 sets out the performance targets according to the three submeasures. The three availability measures collectively represent 1 per cent of DJV's AR at risk under the service standards incentive scheme.

Table I.7 Performance targets

Measure	Performance for maximum penalty (%)	Target performance (%)	Performance for maximum reward (%)	Weight (%)
Planned circuit energy availability	98.90	99.45	100	30
Forced outage circuit energy availability in peak periods	98.47	99.23	100	35
Forced outage circuit energy availability in off-peak periods	98.47	99.23	100	35

Appendix J Pass-through mechanism

Directlink Joint Venture

Transmission Network Revenue Cap

Pass-Through Mechanism

The pass-through mechanism commencing on the following page forms part of the revenue cap set by the Australian Energy Regulator for the Directlink Joint Venture for the period X X 200X to 30 June 2015. [Note: Some dates need to be inserted when the final decision is made].

Directlink Joint Venture Transmission Network Revenue Cap

Pass-Through Mechanism

1. Introduction

In accordance with the National Electricity Rules and the applicable provisions of the National Electricity Code, the Australian Energy Regulator (*AER*) in a final decision dated X X 200X (‘Date of Determination’) set a *revenue cap* (‘Revenue Cap’) to apply to the Directlink Joint Venture (‘TNSP’) for the *regulatory control period* (‘Regulatory Control Period’) from X X 200X (‘Commencement Date’) to 30 June 2015 (‘End Date’). The Revenue Cap includes the following Pass-Through Mechanism.

2. Regulated Pass-Through

2.1 Mechanism forms part of Revenue Cap

This Pass-Through Mechanism forms part of the Revenue Cap. Any Pass-Through Amount determined in accordance with this Pass-Through Mechanism forms part of the *maximum allowed revenue* determined by the Revenue Cap.

2.2 Pass-Through Events

Each of the following is a Pass-Through Event:

(a) a Change in Taxes Event;

(b) an Insurance Event;

(c) a Service Standards Event; and

(d) a Terrorism Event.

2.3 Entitlement or requirement to Pass-Through

If a Pass-Through Event has taken effect or will take effect, then, if the Pass-Through Amount (determined under clause 2.4) for that Pass-Through Event is:

(a) positive, the *maximum allowed revenue* is increased by that Pass-Through Amount provided that the procedure set out in clause 3 is satisfied; or

Note: Clause 3 allows the TNSP, where the Pass-Through Amount is positive, to elect not to pass through that amount, or to pass through only part of that amount, within the Regulatory Control Period. For example, the TNSP may decide to seek to recover part of the amount at a future *revenue cap* reset in order to avoid a significant increase in *transmission service* prices during the Regulatory Control Period.

(b) negative, the *maximum allowed revenue* is decreased by that Pass-Through Amount.

2.4 Pass-Through Amount

The Pass-Through Amount for a Pass-Through Event is determined as follows:

(a) Subject to clauses 2.4(f)–(j), where the Pass-Through Event is a Change in Taxes Event, the Pass-Through Amount is:

(i) Subject to clause 2.4(a)(ii):

(1) the increase or decrease in the amount that the TNSP is required or will be required to pay in a *financial year* within the Regulatory Control Period in providing *prescribed transmission services*;

(2) as compared to the basis upon which the Revenue Cap was set for that *financial year*;

(3) as a direct result of the Change in Taxes Event.

(ii) Where the Change in Taxes Event is part of a package of changes, the amount determined under clause 2.4(a)(i) must be adjusted by the financial effect of the other changes in the package in the relevant *financial year*.

Note: Clause 2.4(a)(ii) is intended to deal with the case where, for example, the introduction of a new tax is intended to be offset in whole or in part by a subsidy or a reduction in another tax. Clause 2.4(a)(ii) will also cover the case where, for example, two or more new taxes are introduced as part of a package.

(b) Subject to clauses 2.4(f)–(j), where the Pass-Through Event is an Insurance Event:

(i) In the case of paragraph (a) of the definition of Insurance Event, the Pass-Through Amount is:

(1) the increase or decrease in premium that the TNSP is required to pay for the relevant *financial year*;

(2) as compared to the premium provided for in the Revenue Cap for that *financial year*.

(ii) In the case of paragraph (b) of the definition of Insurance Event, the Pass-Through Amount is:

(1) the difference between the deductible that the TNSP has incurred or will incur;

(2) as compared to the allowance for that deductible (if any) provided for in the Revenue Cap.

(iii) In the case of paragraphs (c) and (e) of the definition of Insurance Event, the Pass-Through Amount is:

(1) the decrease or increase in the premium that the TNSP is required to pay for the relevant *financial year*;

(2) as compared to the premium provided for in the Revenue Cap for that *financial year*.

(iv) In the case of paragraphs (d) and (f) of the definition of Insurance Event, the Pass-Through Amount is:

(1) the cost, loss or damage that the TNSP has incurred or will incur within the Regulatory Control Period;

(2) as a direct result of the Insurance Event;

(3) to the extent that the cost, loss or damage is not compensated for under any Insurance, and would have been compensated for under the Insurance that was provided for in the Revenue Cap;

(4) less the reduction in premium that the TNSP was required to pay as a result of the Insurance Event (to the extent that the *maximum allowed revenue* has not already been adjusted by this amount).

Note: Clause 2.4(b)(iv)(4) is intended to deal with the case where, for example, the TNSP has discontinued the relevant Insurance but the decrease in premium for the relevant *financial year* was not passed through because the amount was not Material.

(c) Subject to clauses 2.4(e)–(i), where the Pass-Through Event is a Service Standards Event, the Pass-Through Amount is:

(i) the increase or decrease in cost that the TNSP is required or will be required to pay in a *financial year* within the Regulatory Control Period in providing *prescribed transmission services*;

(ii) as compared to the basis upon which the Revenue Cap was set for that *financial year*;

(iii) as a direct result of the Service Standards Event.

(d) Subject to clauses 2.4(e)–(i), where the Pass-Through Event is a Terrorism Event, the Pass-Through Amount is:

(i) the cost, loss or damage that the TNSP has incurred or will incur within the Regulatory Control Period in providing *prescribed transmission services*;

(ii) as a direct result of the Terrorism Event (including action taken in controlling, preventing or suppressing the Terrorism Event).

(e) Where the amount determined under clauses 2.4(a), (b), (c) or (d) is:

(i) positive, the amount must be reduced by the extent to which the TNSP is unable to demonstrate that no act or omission of the TNSP that is inconsistent with *good electricity industry practice*:

(1) caused or aggravated the Pass-Through Event; or

(2) caused or aggravated the resulting amount;

(ii) negative, the amount must be increased by the extent to which any act or omission of the TNSP that is inconsistent with *good electricity industry practice* reduced the potential savings resulting from the Pass-Through Event.

(f) An amount determined under clauses 2.4(a), (b), (c) or (d) must be adjusted by the amount (if any) for such a Pass-Through Event included in the operating expenses or other inputs or formulas used to set the Revenue Cap.

(g) An amount determined under this clause 2.4 must be adjusted for the time cost of money.

(h) Where an amount determined under clause 2.4(a), (b)(i), (b)(iii) or (c) is for a *financial year* that is not fully within the Regulatory Control Period, the amount must be pro rated across the period of time that comes within the Regulatory Control Period and the period of time that is outside of the Regulatory Control Period. The adjusted amount for that part of the *financial year* that comes within the Regulatory Control Period is the Pass-Through Amount for that Pass-Through Event.

Note: Clauses 2.4(a), (b)(i), (b)(iii) and (c) require the Pass-Through Amount to relate to a particular *financial year*. (In contrast, under clauses 2.4(b)(ii), (b)(iv) and (d), the Pass-Through Amount is the deductible incurred at a particular point in time within the Regulatory Control Period (in the case of clause 2.4(b)(ii)) or the total cost, loss or damage incurred over the Regulatory Control Period as a result of the Pass-Through Event (in the case of clauses 2.4(b)(iv) and (d))). Where the Commencement Date is not the start of a *financial year* (or the End Date is not the end of a *financial year*), the amount determined under clause 2.4(a), (b)(i), (b)(iii) or (c) may be for a *financial year* that is not fully within the Regulatory Control Period. In this case, the amount must be apportioned to determine the Pass-Through Amount. Clause 2.4(i), which requires a Pass-Through Amount to be Material, includes, in the definition of Material, a corresponding apportioning mechanism.

(j) An amount determined under this clause 2.4 must be Material. If the amount is not Material, the Pass-Through Amount for the Pass-Through Event is zero.

2.5 Period and form of Pass-Through Amount

(a) The period over which the Pass-Through Amount is to be recovered is to be determined by the TNSP subject to the following conditions:

(i) The first day of the period:

(1) must be the start of a *financial year*;

(2) must not be a date earlier than the Commencement Date;

(3) where the Pass-Through Amount is positive, must not be a date earlier than the date upon which the procedure set out in clause 3 is satisfied;

(4) where the Pass-Through Amount is positive and the date upon which the procedure set out in clause 3 is satisfied falls within the period

commencing on 15 May and ending on 30 June, must be a date after 1 July of that year; and

Note: For example, if the procedure set out in clause 3 is satisfied on 31 May 2007, the first *financial year* in which the *maximum allowed revenue* could be varied to include the Pass-Through Amount would be 1 July 2008 to 30 June 2009. This is because clause 6.5.7 of the National Electricity Rules requires each *Transmission Network Service Provider* to publish the *transmission service* prices to apply for the following *financial year* by 15 May each year.

(5) must not be a date after the End Date.

(ii) The last day of the period:

(1) must be the end of a *financial year*; and

(2) must not be a date after the End Date.

(iii) The period applied by the TNSP under clause 3.6(b) must have been specified by:

(1) the TNSP in a Notice of Proposed Pass-Through under clause 3.2; or

(2) the *AER* in a notice to the TNSP under clause 3.5.

Note: Although a Pass-Through Amount determined under clause 2.4(a), (b)(i), (b)(iii) or (c) relates to a particular *financial year*, clause 2.5(a) allows the TNSP to spread the resulting impact on prices over one or more *financial years*.

(b) If the period over which the Pass-Through Amount is to be recovered consists of two or more *financial years*, the allocation of the Pass-Through Amount over those *financial years* (being the form of the Pass-Through Amount) is to be determined by the TNSP subject to the following condition:

(i) The form applied by the TNSP under clause 3.6(b) must have been specified by:

(1) the TNSP in a Notice of Proposed Pass-Through under clause 3.2; or

(2) the *AER* in a notice to the TNSP under clause 3.5.

3. Procedure

3.1 Initiation of Pass-Through

If a Pass-Through Event has taken effect or will take effect, then, if the Pass-Through Amount (determined under clause 2.4) for that Pass-Through Event is:

(a) positive, the TNSP may give a Notice of Proposed Pass-Through to the *AER* in accordance with clause 3.2; or

(b) negative, the TNSP must promptly (and, in any event, within three *months* of the TNSP becoming aware that the Pass-Through Event had taken effect or will take effect (as the case may be)) give a Notice of Proposed Pass-Through to the *AER* in accordance with clause 3.2.

3.2 Notice of Proposed Pass-Through

A Notice of Proposed Pass-Through must include:

(a) a description of the relevant Pass-Through Event;

(b) the date on which the relevant Pass-Through Event took effect or will take effect;

(c) if the Notice of Proposed Pass-Through is provided under clause 3.1(b), the date on which the TNSP first became aware that the Pass-Through Event had taken effect or will take effect;

(d) the proposed Pass-Through Amount;

(e) the proposed period over which the Pass-Through Amount should apply;

(f) if the proposed period over which the Pass-Through Amount should apply consists of two or more *financial years*, the proposed allocation of the Pass Through-Amount over the *financial years* (being the form of the Pass-Through Amount); and

(g) the supporting information referred to in clauses 3.3(a) and (b).

3.3 Provision of information

(a) The TNSP must attach to its Notice of Proposed Pass-Through such information and documentation as the *AER* requires to enable the *AER* to form an opinion as to:

(i) whether a Pass-Through Event did take effect or will take effect;

(ii) if the Notice of Proposed Pass-Through is provided under clause 3.1(b), whether the TNSP complied with the requirement to give promptly such Notice to the *AER*;

(iii) whether the proposed Pass-Through Amount complies with clause 2.4;

(iv) the period over which the Pass-Through Amount should apply; and

(v) if the period over which the Pass-Through Amount should apply consists of two or more *financial years*, how the Pass-Through Amount should be allocated over the *financial years*.

(b) Without limiting the generality of the obligation in clause 3.3(a), the supporting information must include, where the Pass-Through Event is:

(i) a Change in Taxes Event—the relevant instrument or decision (if any) upon which the Revenue Cap was set, and the relevant instrument or decision implementing the Change in Taxes Event;

(ii) an Insurance Event—the relevant insurance policy, cover note and premium invoice (as the case may be) upon which the Revenue Cap was set, and the relevant insurance policy, cover note and premium invoice (if any) associated with the Insurance Event;

(iii) a Service Standards Event—the relevant decision or Applicable Law (if any) upon which the Revenue Cap was set, and the relevant decision or Applicable Law implementing the Service Standard Event.

3.4 Procedure to be followed by AER

(a) In considering a Notice of Proposed Pass-Through, the *AER* may decide to seek public comment on the Notice.

(b) Disclosure by the *AER* of the supporting information provided by the TNSP in accordance with clauses 3.2(g) and 3.3 shall be governed by the procedure set out in clauses 6.2.5(e) and 6.2.6 of the National Electricity Rules.

3.5 Verification by AER

(a) The *AER* will, within the Assessment Period, form an opinion on:

(i) if the Notice of Proposed Pass-Through was provided under clause 3.1(b), whether the TNSP complied with the requirement to give promptly such Notice to the *AER*;

(ii) whether the Pass-Through Event specified in the Notice of Proposed Pass-Through did take effect or will take effect;

(iii) if so, the Pass-Through Amount (if any) in respect of the relevant Pass-Through Event (determined in accordance with clause 2.4);

(iv) the period over which the Pass-Through Amount should be applied (which must satisfy clauses 2.5(a)(i) and (ii)); and

(v) if the period over which the Pass-Through Amount should be applied consists of two or more *financial years*, how the Pass-Through Amount should be allocated over the *financial years*,

and notify the TNSP in writing of the *AER's* opinion.

(b) If the *AER* does not give notice to the TNSP under clause 3.5(a) on or before the last day of the Assessment Period, then the *AER* is taken to have notified the TNSP of its opinion that the Pass-Through Amount (and the period over, and form in, which the TNSP will apply the Pass-Through Amount) should be as specified by the TNSP in the Notice of Proposed Pass-Through.

3.6 Application of Pass-Through Amount

(a) If the TNSP has received or is taken to have received a notice under clause 3.5, the TNSP must promptly notify its affected customers and *Coordinating Network Service Provider* (if applicable) of:

(i) the Pass-Through Amount (if any) that is set out in the notice from the *AER* under clause 3.5; and

(ii) the period over, and form in, which the Pass-Through Amount is to be applied (to be determined by the TNSP in accordance with clause 2.5).

(b) Where the Pass-Through Amount is:

(i) positive, the TNSP may, in accordance with clause 2.3(a), after providing notice in accordance with clause 3.6(a), increase its *maximum allowed revenue* by the Pass-Through Amount over the period, and in the form, specified by the TNSP in the notice under clause 3.6(a);

(ii) negative, the TNSP must, in accordance with clause 2.3(b), regardless of whether or not the TNSP has provided notice in accordance with clause 3.6(a), decrease its *maximum allowed revenue* by the Pass-Through Amount specified or taken to be specified in the notice from the *AER* under clause 3.5 over the period, and in the form determined by the TNSP in accordance with clause 2.5.

4. Definitions

4.1 National Electricity Rules definitions

In this Pass-Through Mechanism, unless the context otherwise requires:

(a) words appearing in italics have the meaning assigned to them from time to time by the National Electricity Rules; and

(b) if a word in italics is no longer defined in the National Electricity Rules, it will have the meaning last assigned to it by the National Electricity Rules.

4.2 Additional definitions

In this-Pass Through Mechanism, unless the context otherwise requires:

Applicable Law means any legislation, delegated legislation (including regulations), codes, rules, licences, guidelines, determinations and directions relating to the provision of one or more *prescribed transmission services*, and includes the National Electricity Law and the National Electricity Rules.

Assessment Period means:

(a) two *months* from the date the *AER* receives from the TNSP a Notice of Proposed Pass-Through that satisfies the requirements of clauses 3.2 and 3.3; or

(b) if the *AER* so notifies the TNSP prior to the expiry of the initial two *month* period, four *months* from the date the *AER* receives from the TNSP a Notice of Proposed Pass-Through that satisfies the requirements of clauses 3.2 and 3.3.

Note: For example, if the *AER* receives from the TNSP a valid Notice of Proposed Pass-Through on 31 May 2007, the TNSP must receive written notice of the *AER's* opinion on or before 31 July 2007 (or 30 September 2007 in the event that the initial period is extended).

Authority means any government department, instrumentality, minister, agency, statutory authority or other body in which a government has a controlling interest, and includes the *AEMC*, *NEMMCO*, the *AER* and the *ACCC* and their successors.

A **Change in Taxes Event** occurs where the following conditions are satisfied:

(a) the following condition is satisfied:

(i) the way in which, or rate at which, a Relevant Tax is calculated is changed (including a change in the application or official interpretation of a Relevant Tax); or

(ii) a Relevant Tax is removed; or

(iii) a new Relevant Tax is imposed; and

(b) the change, removal or imposition is made:

(i) on or after the Date of Determination; and

(ii) on or before the End Date.

Commencement Date means X X 200X, being the first day of the period covered by the Revenue Cap.

Date of Determination means X X 200X, being the date of the *AER's* final decision setting the Revenue Cap.

End Date means 30 June 2015, being the last day of the period covered by the Revenue Cap.

Insurance means insurance whether under a policy or a cover note or other similar arrangement.

An **Insurance Event** occurs where, in relation to a risk that was the subject of Insurance and for which a premium was provided for in the Revenue Cap:

(a) the following conditions are satisfied:

(i) the TNSP has paid or is required to pay a premium for that risk;

(1) on or after the Date of Determination; and

(2) on or before the End Date;

(ii) the premium relates to a *financial year* within the Regulatory Control Period; and

(iii) the cost of the premium is higher or lower than the premium provided for in the Revenue Cap for that *financial year*; or

Note: For example, the TNSP may receive, in relation to the relevant risk, an invoice on 1 July 2008 for the period 1 August 2008 to 31 July 2009; and an invoice on 1 July 2009 for the period 1 August 2009 to 31 July 2010. To determine whether a Pass-Through Event has occurred, it would be necessary to determine the total premium paid with respect to the period 1 July 2009 to 30 June 2010.

(b) the following conditions are satisfied:

(i) the risk eventuates within the Regulatory Control Period;

(ii) the TNSP has incurred or will incur, within the Regulatory Control Period, all or part of a deductible; and

Note: For the avoidance of doubt, clause (ii) requires confirmation from the relevant insurance provider that the risk comes within the scope of the relevant Insurance.

(iii) that amount is higher or lower than the allowance for the deductible (if any) provided for in the Revenue Cap; or

(c) the following condition is satisfied:

(i) Insurance for the risk for a *financial year* within the Regulatory Control Period becomes unavailable to the TNSP:

(1) on or after the Date of Determination; and

(2) on or before the End Date; or

(d) the following conditions are satisfied:

(i) Insurance for the risk for a *financial year* within the Regulatory Control Period becomes unavailable to the TNSP:

(1) on or after the Date of Determination; and

(2) on or before the End Date;

(ii) the uninsured risk eventuates within that *financial year* and within the Regulatory Control Period; and

(iii) that event would have been insured by the Insurance that was provided for in the Revenue Cap in relation to that risk; or

(e) the following conditions are satisfied:

(i) Insurance for the risk for a *financial year* within the Regulatory Control Period becomes available to the TNSP on terms materially different from those upon which the Revenue Cap was set:

(1) on or after the Date of Determination; and

(2) on or before the End Date; and

(ii) the TNSP either does not continue the relevant Insurance or continues the Insurance on different terms; or

(f) the following conditions are satisfied:

(i) Insurance for the risk for a *financial year* within the Regulatory Control Period becomes available to the TNSP on terms materially different from those upon which the Revenue Cap was set:

(1) on or after the Date of Determination; and

(2) on or before the End Date;

(ii) the TNSP either does not continue the relevant Insurance or continues the Insurance on different terms;

(iii) the risk eventuates within that *financial year* and within the Regulatory Control Period; and

(iv) that event would have been insured or would have been fully insured by the Insurance that was provided for in the Revenue Cap in relation to that risk.

Material: For the purpose of clause 2.4(j):

(a) Subject to paragraph (b), an amount determined in accordance with clauses 2.4(a)–(h) in relation to a single Pass-Through Event is **Material** if that amount is equal to, or greater than, $X [Note: Approximately 1 per cent of the TNSP's average *maximum allowed revenue* for a *financial year*, estimated at the time the Revenue Cap is set. The monetary amount is inserted at the time of the final decision on the Revenue Cap].

(b) If:

(1) the amount is determined under clause 2.4(a), (b)(i), (b)(iii) or (c);

(2) the amount is for a *financial year* that is not fully within the Regulatory Control Period; and

(3) the amount is adjusted in accordance with clause 2.4(h),

the amount is **Material** if that amount is equal to or greater than $X pro rated using the same formula as for clause 2.4(h).

National Electricity Code means the 'National Electricity Code' as in force immediately before the date of commencement of section 12 of the *National Electricity (South Australia) (New National Electricity Law) Amendment Act 2005* (SA).

National Electricity Rules has the meaning assigned to it from time to time by the National Electricity Law set out in the Schedule to the *National Electricity (South Australia) Act 1996* (SA).

Notice of Proposed Pass-Through means a notice described in clause 3.2.

Pass-Through Amount means a variation to the TNSP's *maximum allowed revenue* as a result of a Pass-Through Event determined in accordance with this-Pass Through Mechanism (which form part of the TNSP's Revenue Cap). A Pass-Through Amount may be positive or negative.

Pass-Through Events means the events specified in clause 2.2.

Regulatory Control Period means the period starting on the Commencement Date and ending on the End Date.

Relevant Tax means any tax, rate, duty, charge, levy, rebate, Authority fee or other like or analogous impost that is:

(a) paid, to be paid, or taken to be paid by the TNSP in connection with the provision of *prescribed transmission services*; or

(b) included in the operating expenses or other inputs used to determine the Revenue Cap,

but excludes:

(c) income tax (or State equivalent tax) and capital gains tax;

(d) penalties and fines (including penalties and interest for late payment relating to any tax, rate, duty, charge, levy, Authority fee or other like or analogous impost);

(e) charges and Authority fees paid or payable in respect of a Service Standards Event;

(f) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties;

(g) any tax, rate, duty, charge, levy, rebate, Authority fee or other like or analogous impost that replaces the imposts referred to in (c)–(f).

Revenue Cap means the *revenue cap* set by the *AER* in accordance with the National Electricity Rules and the applicable provisions of the National Electricity Code in a final decision issued on the Date of Determination to apply to the TNSP for the Regulatory Control Period.

A **Service Standards Event** occurs where the following conditions are satisfied:

(a) the following condition is satisfied:

(i) a decision is made by an Authority; or

(ii) an Applicable Law is introduced or amended;

(b) the decision, introduction or amendment is made:

(i) on or after the Date of Determination; and

(ii) on or before the End Date;

(c) the decision, introduction or amendment has the effect of, within the Regulatory Control Period:

(i) imposing, removing or varying minimum standards on the TNSP relating to *prescribed transmission services*;

(ii) altering the nature or scope of services that comprise the *prescribed transmission services*;

(iii) varying the manner in which the TNSP is required to undertake any activity forming part of *prescribed transmission services*; or

(iv) increasing or decreasing the TNSP's risk in providing the *prescribed transmission services*,

from that upon which the Revenue Cap was set.

A **Terrorism Event** occurs where the following conditions are satisfied:

(a) an act (including, but not limited to, the use of force or violence and/or the threat thereof) by any person or group(s) of persons (whether acting alone or on behalf of or in connection with any organisation(s) or government(s)), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence any government and/or to put the public, or any section of the public, in fear), occurs; and

(b) the act occurs:

(i) on or after the Date of Determination; and

(ii) on or before the End Date.

TNSP means the Directlink Joint Venture (Emmlink Pty Ltd and HQI Australia Ltd Partnership), being the owners of the Directlink transmission network.

4.3 References to certain general terms

Unless the contrary intention appears, a reference in this Pass-Through Mechanism to:

(a) **(variations or replacement)** a document (including this Pass-Through Mechanism) includes any variation or replacement of it;

(b) **(clauses)** a clause is a reference to a clause in this Pass-Through Mechanism;

(c) **(reference to statutes)** a statute, ordinance, code, rules or other law includes regulations and other instruments under it and consolidations, amendments, re-enactments or replacements of any of them;

(d) **(singular includes plural)** the singular includes the plural and vice versa;

(e) **(person)** the word ‘person’ includes an individual, a firm, a body corporate, a partnership, a joint venture, a syndicate, an unincorporated body or an association, or any Authority;

(f) **(successors)** a particular person includes a reference to the person’s successors, substitutes (including persons taking by novation) and assigns;

(g) **(meaning not limited)** the words ‘include’, ‘including’, ‘for example’ or ‘such as’ are not used as, nor are they to be interpreted as, words of limitation, and, when introducing an example, do not limit the meaning of the words to which the example relates to that example or examples of a similar kind;

(h) **(reference to anything)** anything (including any amount) is a reference to the whole and each part of it.

4.4 Headings

Headings (including those in brackets at the beginning of paragraphs) are for convenience only and do not affect the interpretation of this Pass-Through Mechanism.

Appendix K Establishing the revenue cap and CPI – X adjustment

Step 1	
Estimate the decision parameters at the start of the period: Regulated asset base (A) Operating and maintenance expenditure (O) Capital expenditure (K) Nominal vanilla WACC (r) Forecast inflation (f) Forecast taxation (T)	Estimate forecast variables for each year of the regulatory period: O, K, T, A. That is, estimate: $O(i)$, $K(i)$,$T(i)$, $A(i)$ for $i = 1, 2, \ldots 5$
Step 2	
Calculate total revenue (TR) on the basis of forecasts, where TR is the unsmoothed revenue.	Sum the forecast elements of cost for each year (accounting for any forecast efficiency improvements) to determine total revenue for each year: $TR(i) = O(i) + [(A(i) - A(i + 1) + K(i)] + r \times A(i) + T(i)$ for $i = 1, 2, \ldots 5$
Step 3	
Choose the allowed revenue (AR) to set the revenue cap for year 1. Usually select $AR(1) = TR(1)$.	The smoothed revenue that will be used as the basis for the forecast revenue cap in the following years via the CPI – X adjustment mechanism is given by: $AR(i + 1) = AR(i) \times (1 + f(i)) \times (1 - X)$ for $i = 1, 2, \ldots 4$
Step 4	
Calculate the X (smoothing) factor.	Determine the smoothed revenue to give the same net present value as the total revenue using WACC as the discount rate: $NPV(TR(1), \ldots TR(5)) = NPV(AR(1), \ldots AR(5))$
Step 5	
Calculate the maximum allowed revenue (MAR).	Allowed revenue is adjusted by a service standards performance incentive (PI): $MAR = AR + PI$
Adjustment at end of year *i*	
Establish actual revenue cap (ARC) for year ($i + 1$), given $AR(1) = ARC(1)$.	Re-apply CPI – X adjustment using actual consumer price index (CPI) outcome for the previous year (that is, $\Delta CPI(i)$): $ARC(i + 1) = ARC(i) \times (1 + \Delta CPI(i)) \times (1 - X)$ for $i = 1, 2 \ldots 4$