AUSTRALIAN ENERGY REGULATOR

Directlink Joint Venturers' Application for Conversion and Revenue Cap

Decision

3 March 2006

Contents

Glossary

ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
AR	allowed revenue
capex	capital expenditure
code	National Electricity Code
CPI	consumer price index
DJV	Directlink Joint Venturers (that is, HQI Australia Ltd Partnership and Emmlink Pty Ltd as owners of Directlink, each entitled to its agreed share of the transmission services provided by Directlink). For convenience, the two entities are described collectively as DJV and referred to in the singular for this decision.
EV	economic value
IES	Intelligent Energy Systems
kV	kilovolt
MAR	maximum allowed revenue
MNSP	market network service provider
MW	megawatt
MWh	megawatt hour
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NERA	NERA Economic Consulting
NPV	net present value
NSW	New South Wales
opex	operating and maintenance expenditure
PB Associates	Parsons Brinckerhoff Associates

PTRM	Post-tax revenue model
QNI	Queensland – New South Wales Interconnector
RAB	regulated asset base
rules	National Electricity Rules
SRP	*Statement of Principles for the Regulation of Electricity Transmission Revenues*, 8 December 2004
TNOs	transmission network owners
TNSP	transmission network service provider
USE	unserved energy
VCR	Value of customer reliability
VENCorp	Victorian Energy Networks Corporation
VOLL	value of lost load
WACC	weighted average cost of capital

Summary

On 6 May 2004, the Directlink Joint Venturers (DJV) submitted an application to convert Directlink to a regulated network and be eligible to receive a maximum allowed revenue (MAR), in accordance with clause 2.5.2(c) of the National Electricity Code (code).

The Australian Energy Regulator's (AER) draft decision (8 November 2005) considered that Directlink should be allowed to convert to a prescribed (regulated) service.[1] The draft decision concluded that Directlink is able to meet the requirements for conversion to a prescribed service. Consultation on the draft decision has raised no new material in relation to Directlink being allowed to convert to a prescribed service.

The AER's assessment of Directlink under the regulatory test is set out in the draft decision and is not repeated in this decision. The regulatory test assessment indicated that none of the alternative projects are optimal and that, accordingly, Directlink would not be justified. As a result, it was considered that the appropriate regulatory asset value should be less than the cost of Directlink or one of the alternative projects. The draft decision proposed that DJV's opening regulated asset base (RAB) be determined on the basis of the expected market benefits rather than the construction cost of the project. On this basis, upon conversion, Directlink's opening RAB was proposed to be set at $116.68 million (at 1 July 2005).

There were seven submissions responding to the draft decision. This decision considers substantive new material raised in submissions and issues which were not raised in submissions but required final resolution following the draft decision, and sets out the AER's final decision in relation to DJV's application.

Issues raised by submissions

The following sections summarise the AER's conclusions on substantive new material raised by submissions.

Value of unserved energy

DJV and the joint transmission network owners (TNOs) proposed that the wholesale market price cap of $10,000 per MWh does not need to be considered in the estimate of market benefits under the regulatory test. DJV argued that the value of unserved energy (USE) in Victoria of $29,000 per MWh is a credible estimate. The AER considered that values of $10,000 per MWh and $29,600 per MWh should both be employed for the value of USE when applying the regulatory test and estimating the economic benefits of Directlink. The AER concluded that, in the absence of specific information on the value of USE in each region, it is appropriate to use an approach that is consistent with the ACCC's application of the 1999 regulatory test in the Murraylink decision. In addition, the use of both values provides a degree of

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[1] Appendix A provides a summary of the review process undertaken by the AER in consideration of DJV's application

confidence that the scenarios employed in the regulatory test will span the credible range.

Use of the median to estimate market benefits

DJV proposed that the AER should use the mean of the gross market benefits across the credible scenarios to set its asset value instead of the median as proposed in the draft decision. The AER has maintained its position taken in the draft decision. The AER considered it is important that the valuation methodology employed for Directlink is consistent with the principles underlying the regulatory test. That is, a project cannot satisfy the regulatory test unless its median net economic value is positive. If the mean value had been adopted then the asset value for Directlink would have been higher than if it had satisfied the regulatory test, which was not the case.

Understatement of benefits

DJV submitted that the benefits adopted in the draft decision could under estimate the actual benefits. It argued that competition benefits and other types of technical support benefits have not been included. The AER agrees that potential competition benefits have not been included in the analysis. However, in the absence of further evidence, it is not possible to determine whether competition benefits are likely to be significant. The technical benefits of Directlink have been fully incorporated.

Potential deferral of line 966

DJV claimed that the installation of a second transformer at Molendinar in the summer of 2006–07 would provide additional capacity to flow south across Directlink into NSW and avoid the need to upgrade line 966. Information received by the AER supported the draft decision to disallow any deferral benefit of line 966 (132 kV Armidale to Koolkhan). As such, no deferral of the uprating of line 966 is attributed to Directlink.

Debt margin

DJV and the TNOs proposed that the estimation methodology employed by CBASpectrum understates the yields (downward bias) on low rated, long dated corporate bonds and suggested that it is more appropriate to use Bloomberg's estimated debt margins. The AER conducted a review of the bond yield estimates provided by CBASpectrum and Bloomberg. It appears that the estimated A rated, long term fair yields (debt margins) by Bloomberg are more consistent with the observed yields of similarly rated actual bonds. Accordingly, in this instance, the AER will use the Bloomberg data service for determining the benchmark debt margin for DJV.

Regulatory control period

The South Australian Minister for Energy and Metgasco suggested that the regulatory control period should be less than 10 years. The AER considered that DJV's request for a 10 year regulatory control period is justified. DJV has limited opportunity to substantially reduce its costs because there is no allowance for capital expenditure and only an efficient operating expenditure has been allowed. In addition, the AER does not expect that a regulatory reset for DJV would involve another regulatory test assessment to adjust its asset value.

Service standards

DJV proposed a number of amendments to the service standards scheme. The AER has implemented some adjustments:

- to amend the s-factor and formula tables as outlined in the draft decision to reflect circuit availability as a percentage
- to insert definitions of a Forced outage event and a Scheduled outage event
- to further clarify the measurement of circuit availability according to a capacity weighting.

Presentation of the final decision

For the purposes of achieving regulatory and commercial certainty, DJV submitted that the decision can be described in clearer terms. The AER has made minor adjustments to the presentation of the revenue cap decision to improve its clarity. No substantive adjustments have been made.

Issues requiring final resolution

The draft decision left open a number of issues for final resolution and which were not raised in submissions. The following sections summarise the AER's conclusions on these issues.

Reliability of Directlink

The latest reliability data suggests that Directlink is currently operating at a level that is consistent with the assumptions employed in the estimation of the market benefits. In the event that this is not the case, there are three factors to suggest that Directlink will undertake further corrective action. First, DJV has provided a commitment in correspondence to improve Directlink's reliability. Second, DJV will have a reliability obligation in its connection agreement with Country Energy and Country Energy will have an incentive to ensure that adequate reliability is provided by Directlink. Third, the service standards scheme for DJV will provide financial incentives to achieve a higher level of reliability, which will be beneficial to the market as a whole.

Updating the WACC

The draft decision noted that the AER would update the weighted average cost of capital (WACC) for prevailing market bond yields when finalising its decision because some parameters vary over time according to market conditions. A post–tax nominal return on equity of 11.32 per cent, combined with a pre–tax nominal cost of debt of 6.32 per cent, which equates to a nominal vanilla WACC of 8.32 per cent, provides an appropriate cost of capital for DJV.

Pass-through mechanism

The draft decision noted that some specific dates and the quantum of the materiality threshold would need to be inserted in the pass-through mechanism at the time of finalising the decision. The pass-through mechanism has been updated to insert specific dates and to set the materiality threshold at $126,000. This figure is based on one per cent of DJV's average MAR for a financial year.

Decision

Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision. Under clause 2.5.2(c) of the code, the AER determines that, on and from the time Directlink's network service ceases to be classified as a market network service:

1. Directlink's network service will be a prescribed service with an opening regulated asset base of $116.68 million at 1 July 2005.

2. The Directlink Joint Venturers will have a revenue cap for a regulatory control period ending on 30 June 2015. Its MAR under this revenue cap will be as follows:

   MAR_1 = the AR for 2005–06 (year 1) of $11.75 million, to be adjusted on a pro rata basis according to the actual date of conversion

   X = the smoothing factor of 1.31 per cent, which represents the rate by which the AR falls in real terms.

   The formula used to calculate the MAR for each subsequent year is:

   $$MAR_t = AR_t + \left(\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct} \right) + P_t$$

   where:

   $$AR_t = AR_{t-1} \times (1 + \Delta CPI) \times (1 - X).$$

3. Subject to paragraph 4 below, this decision will lapse if Directlink's network service has not ceased to be classified as a market network service on or before Monday, 10 April 2006.

4. In the event that an application is made for judicial review of this decision before Directlink's network service has ceased to be classified as a market network service, this decision will lapse 28 days after the day on which any such application is withdrawn, dismissed, or otherwise discontinued.

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1 Introduction

1.1 Structure of document

This final decision sets out the AER's consideration of issues raised by submissions and matters which were not raised in submissions but requiring final resolution from the draft decision. It consists of four chapters:

- chapter 1 outlines the application and summarises the main elements of the draft decision
- chapter 2 discusses the AER's consideration of substantive new material raised by submissions and provides a list of other issues raised that were not regarded as substantive new material
- chapter 3 examines issues which were not raised in submissions but requiring final resolution following the draft decision
- chapter 4 sets out the AER's decision on DJV's conversion and the revenue cap.

Appendices A to C provide details of the review process, the service standards scheme and the pass-through mechanism.

1.2 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. It forms one of the links between the NSW and Queensland electricity regions in the National Electricity Market (NEM). Directlink has a nominal capacity of 180 MW.

Directlink is owned by Emmlink Pty Ltd and HQI Australia Ltd Partnership (50 per cent each).[2] Emmlink Pty Ltd and HQI Australia Ltd Partnership are participants in the unincorporated Directlink Joint Venture which operates Directlink and each is entitled to its agreed share of the transmission services provided by Directlink. For convenience, these two entities are described collectively as DJV and referred to in the singular throughout this decision.

Directlink's network service is currently classified as a market network service. As a market network service provider (MNSP), DJV earns revenue from the NEM by providing Directlink's market network 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 regulated network and be eligible to receive a maximum allowed revenue (MAR), in accordance with clause 2.5.2(c) of the National Electricity Code (code). The Australian Energy Regulator's

[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.

(AER) draft decision (8 November 2005) considered that Directlink should be allowed to convert to a prescribed (regulated) service—see appendix A for a summary of the review process. Upon conversion, Directlink's opening regulated asset base (RAB) was proposed to be set at $116.68 million (at 1 July 2005).

1.3 Main elements of the draft decision

The draft decision concluded that Directlink is able to meet the requirements for conversion to a prescribed service. Following the release of the draft decision, no substantive new material was raised in relation to the draft decision to allow Directlink to convert to a prescribed service.

An assessment of Directlink under the regulatory test is set out in the draft decision and is not repeated in this decision. The regulatory test assessment indicated that neither Directlink nor its alternative projects are optimal and, hence, Directlink would not be justified. As a result, it was considered that the appropriate regulatory asset value should be less than the cost of Directlink. In addition, the asset value of Directlink should be less than the capital cost of alternative 2, which is the alternative project that comes closest to satisfying the regulatory test.

It was proposed that DJV's opening RAB be determined on the basis of the expected market benefits rather than the construction cost of the project. No submissions objected to this approach.

The draft decision proposed a MAR for DJV based on its RAB and forecast operating and maintenance costs. DJV and the joint transmission network owners took issue with one aspect of the proposed weighted average cost of capital. No other submissions commented on this aspect of the draft decision.

In addition to proposing a MAR, the draft decision also proposed a service standards incentive scheme and a pass-through mechanism for adjusting the MAR. The draft decision proposed a 10 year regulatory period. The South Australian Minister for Energy and Metgasco questioned the use of a 10 year regulatory period.

2 Issues raised by submissions

2.1 Introduction

Table 2.1 lists the submissions received by the AER on the draft decision.[3]

Table 2.1 Submissions to the draft decision

Interested party	Date received
TransGrid	7 December 2005
Country Energy	7 December 2005
Directlink Joint Venturers	9 December 2005
Joint Transmission Network Owners	9 December 2005
Metgasco	9 December 2005
Powerlink	12 December 2005[4]
Hon Patrick Conlon MP	31 December 2005[5]

This chapter sets out the AER's consideration of substantive new material raised by submissions in relation to specific issues. The sub–sections on each issue provide:

- an overview of submissions on that issue
- the considerations
- the conclusion.

In addition, a list of other issues raised by submissions, which were not regarded as substantive new material, is presented.

2.2 Value of unserved energy

2.2.1 Issues raised in submissions

DJV submitted that, for the purposes of the regulatory test, the (NEM) wholesale market price cap of $10,000 per MWh is an inappropriate value of unserved energy (USE) or value of lost load (VOLL) to customers. It claimed that there is substantial evidence to suggest that a credible estimate of the value of USE across the NEM is significantly greater than $10,000 per MWh. DJV remained of the view that the value of USE in Victoria is similar to the value in other Australian regions and that $29,600 per MWh is the credible estimate for the value of USE for this assessment. DJV also

3 Appendix A summarises the consultation undertaken for the consideration of DJV's application.
4 The submission by Powerlink was received after the closing date of Friday 9 December 2005 and the AER has had regard to it.
5 The submission by Minister Conlon was received after the closing date of Friday 9 December 2005 and the AER has had regard to it.

suggested that it might be valid to consider both $10,000 and $50,000 per MWh as sensitivity cases.[6]

The joint transmission network owners (TNOs) (comprising of TransGrid, ElectraNet, Powerlink, SP AusNet and Transend) also submitted that it is not appropriate to use the market cap (VOLL) in the estimate of market benefits under the regulatory test. This is because the VOLL is generally accepted as being significantly below the value that customers place on having a reliable electricity supply. The TNOs cited a review of VOLL undertaken by NECA, that proposed VOLL be increased from $5,000 to $10,000 per MWh, followed by a further increase to $20,000 per MWh to better reflect the value of electricity supply.[7]

2.2.2 Draft decision

DJV's application proposed a value of USE of $29,600 per MWh, which was developed by VENCorp.

The AER's consultant, Intelligent Energy Systems (IES), considered the USE values of $10,000 per MWh and $29,600 per MWh contained in the modelling of interregional benefits was sufficient for the sensitivity analysis in the regulatory test. 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 $10,000 per MWh market price cap of VOLL and VENCorp's estimated value of customer reliability ($29,600 per MWh). IES stated that both the market price cap and VENCorp's estimate need to be considered for the purposes of the 1999 regulatory test and it advised that equal weighting should be applied to both values.

In the draft decision, the AER noted 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.

The AER acknowledged that VOLL does not necessarily reflect the real or true value of USE, which varies with customer type and location and the sequence in which the transmission network service providers (TNSPs) shed load. It was, however, the AER's view that DJV had not substantiated that the estimate of $29,600 per MWh better reflected the USE value to customers outside of the Victorian region considered in VENCorp's analysis.

6 DJV, *Submission in Response to the AER's Draft Decision of 8 November 2005*, Port Macquarie, 9 December 2005, pp. 13-16.

7 Joint Transmission Network Owners, *AER Draft Decision—Directlink Conversion to Regulated Status*, 9 December 2005, p. 2.

Given the uncertainty about the value of USE, the view of the AER in the draft decision was that both $29,600 per MWh and $10,000 per MWh should be used for the regulatory test assessment, with equal weighting in the credible scenarios and for setting the opening regulated asset base (RAB) of Directlink.[8]

2.2.3 Considerations

The AER engaged IES to further comment and provide reasoning on an appropriate value of USE for application of the regulatory test. IES stated that, in accordance with its previous advice, equal weighting should be given to the values of $10,000 per MWh and $29,600 per MWh in the application of the regulatory test to Directlink.[9]

In forming its conclusion on which value(s) of USE should be applied in the context of determining an opening RAB for Directlink, IES advised that the following elements need to be considered:

- estimating the interregional benefits
- specification of the regulatory test
- background to the VENCorp value of USE
- Directlink's context.

The AER's consideration of these elements is described in the sections below.

Estimating the interregional benefits

Types of benefits

Interregional benefits are considered in four broad categories:

Energy benefits. When two regions are linked, the most efficient generating units in each region can be used to service the combined load. For example, if region A has a portfolio of low cost generation units while region B has a portfolio of high cost generation units then savings can be made by linking the two regions and using more units from region A. It is expected that total fuel costs will be lower when the two regions are linked.

Deferral of generator entry. New generating units enter the market when it is profitable to do so. When two regions are linked, spare capacity in one region can be used to service excess demand in the other region. As a result the interconnector tends to moderate prices and this can defer new generating units until demand is sufficiently high to drive electricity prices higher in both regions. Savings are derived from the deferral of generating units for a period.

Deferral of reserve trader capacity. Currently, NEMMCO has a role as reserve trader. When NEMMCO becomes concerned that there may not be sufficient capacity

8 AER, *Directlink Joint Venture Application for Conversion and Revenue Cap—Draft Decision*, Canberra, 8 November 2005, p. 121.

9 IES, *Review of Issues Contained in the DJV Submission on Directlink Economics*, 21 February 2006, p. 2.

in a region to ensure the reliability standard is met it can enter the market to procure additional generation capacity. When two regions are linked, spare capacity in one can be used to service excess demand in the other. As a result, there can be a reduced need for NEMMCO to acquire reserve capacity.

Residual reliability benefits. The current reliability standard is set at 0.002 per cent. Activity in the market, however, can produce outcomes that are better (that is, closer to zero). To the extent that the interconnector produces higher levels of reliability than 0.002 per cent this provides additional benefits.

Relationship between benefits

The four broad benefit categories listed above are related—that is, positive benefits in one category can be offset by negative benefits in another. Consider the following examples:

- The presence of the interconnector may reduce profitability and defer the entry of a new generating unit (positive generator entry benefit). But this could produce an unacceptable risk of exceeding the reliability standard leading to NEMMCO entering the market to acquire additional generation (negative reserve trader benefit). If NEMMCO procures the unit that was deferred the two benefits will exactly offset (assuming the same technology in both projects).
- The presence of the interconnector may defer the entry of a new generating unit that has better fuel efficiency than the generators that are currently operating. As a consequence, the positive generator entry benefits could be offset by negative energy savings.
- The deferral of new generation (positive generator entry benefit) could increase unreliability (negative residual reliability benefit).
- If a new gas fired plant is deferred for a time, the plant might be deferred indefinitely if a new coal fired plant becomes viable during the deferral period. This can have significant consequences for capital and fuel costs.

In part, this interdependency arises because new generation entry was assumed to be lumpy.[10] This means that as the level of demand approaches supply limits, average prices and unreliability start to rise. When the profitability threshold is attained, there is new entry and prices and unreliability fall. Therefore, deferral of new generation can cause unreliability to remain at a high level. For example, if there is significant deferral of new generation in the presence of the interconnector this can lead to higher unreliability. In this case, the interconnector produces a negative residual reliability benefit.

Impact of the value of unserved energy on interregional benefits

The value of USE only enters the calculation of benefits at one point—the calculation of the residual reliability benefit. However, an increase in the value of USE can either increase or decrease the total benefit depending on the circumstances. Consequently, it is not possible to determine the impact of the value of USE in advance.

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10 That is, new generation can only be added in large increments (say 50 MW).

In practice, estimates of interregional benefits are highly unstable. This occurs because the contribution from individual components can switch from positive to negative following minor adjustments to the modelling. This instability is compounded by the interdependence between the individual components. Any single estimate of interregional benefits will be subject to substantial uncertainty.

This instability is observed in the modelling that has been performed for Directlink. In the low and medium growth scenarios, the total interregional benefits increase as the value of USE increases. Conversely, in the high growth scenario, the total interregional benefits decrease as the value of USE increases.

Summary

The chosen value of USE can have a material effect on the estimated values of the interregional benefits and it is not possible to determine the impact prior to modelling the benefits. Consequently, before employing any single value of USE, it is necessary to have a high degree of confidence in that value. Ideally, the appropriate value of USE should be determined prior to estimating the interregional benefits.

Specification of the regulatory test

1999 regulatory test

The 1999 regulatory test states that in determining the market benefits, the following should be considered:

> Reasonable forecast of…the value of energy to electricity consumers as reflected in the level of VOLL.[11]

In promulgating the regulatory test, the ACCC did not specify the value attributable to VOLL for the purposes of calculating the value of energy to electricity consumers. The Ernst & Young report, however, which the ACCC commissioned to consider the form of the augmentation test, noted:

> The key issue, therefore, is choosing the appropriate level of VOLL. Should it be consistent with the market VOLL, or the VOLL required to maintain reliability…we would make the following recommendations:
>
> - that VOLL should be applied consistently between generation, demand and transmission in all benefits analysis and;
> - scenarios using both a market based VOLL…and a reliability based VOLL…should be assessed and the resulting net benefits should be factored into the ultimate decision on augmentation.[12]

Murraylink decision

In applying the 1999 regulatory test to Murraylink as part of assessing the Murraylink Transmission Company's conversion application, the ACCC considered that it was not inconsistent with a regulatory test assessment for the value of VOLL to be based

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

12 Ernst & Young, *Review of the Assessment Criterion for New Interconnectors and Network Augmentation –Final Report to ACCC*, March 1999, p. 28.

on the current market price cap and a level of VOLL based on an objectively identified measure. The ACCC was of the view that:

> …the current wording of the regulatory test does not specify a value of VOLL to be applied for the calculation of the gross market benefits. The Commission concurs with interested parties that the VOLL specified in the code is a wholesale market price cap and does not necessarily reflect the real or true value of lost load to end user customers, which may vary from customer type and location. Therefore, the Commission is of the view that where an appropriate value of customer reliability has been determined for a region or sub–region, it would be not inconsistent with the regulatory test to be used in the calculation of the estimated benefits to end–users from greater reliability. In the absence of an accurate value for the value of customer reliability, the VOLL specified in the code should be used. However, the Commission notes that for the purposes of sensitivity analysis, it is appropriate for different values of VOLL to be tested. [13]

The ACCC also noted that while a value of $29,600 per MWh (an average for the Victorian system) may be appropriate for Victorian customers, it did not have a view as to its appropriateness in the case of interconnectors which were expected to service the South Australian region.

2004 review of the regulatory test

In its 2004 review of the regulatory test, the ACCC noted the general concern that the use of VOLL may not always be an appropriate value for making a determination of the true value of lost load to customers. Some submissions, however, argued that using VOLL would be in accordance with both the code as well as principles of competitive neutrality. The ACCC's draft decision proposed that the regulatory test should reference both VOLL and VENCorp's value of customer reliability (VCR) as a measure of the value of electricity to consumers. The ACCC considered that recognising both VOLL and VCR, where it has been estimated, would achieve a balance between the principles of competitive neutrality and economic efficiency.

As part of finalising its decision, the ACCC noted that VCR is a specific measurement technique used by VENCorp for the Victorian region of the NEM and there may be other means of determining the cost of supply reliability for other regions. The ACCC considered it appropriate to replace the description which previously appeared in the 1999 regulatory test with the expression 'reasonable forecasts of value of electricity to consumers'. Irrespective of the value selected, the ACCC also considered that an assessment of the regulatory test should include sensitivity analysis conducted using different values of electricity to consumers.

Summary

In applying the 1999 regulatory test to Murraylink, the ACCC employed a broad interpretation in relation to the value of unserved energy that could be adopted. It stated that where an appropriate VCR has been determined for a region or sub–region, it could be used in the calculation of the estimated benefits and that in the absence of an accurate value for the VCR, the VOLL specified in the code should be used. Irrespective of the value selected, the ACCC also considered that an assessment of the regulatory test should include sensitivity analysis conducted using different values of electricity to consumers.

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[13] ACCC, *Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue*, Canberra, 1 October 2003, p. 86.

Background to VENCorp's value of USE

There are three main studies that have been done on the value of USE in Australia:

1. Assessment of the Value of Customer Reliability prepared by Charles River Associates (CRA) for VENCorp (Victorian customers), December 2002.
2. Monash for VENCorp (Victorian customers), 1997.
3. Monash for TransGrid (NSW customers), 1998.

The CRA study estimates the VCR for the Victorian region. It finds the VCR for different sectors as outlined in table 2.2.

Table 2.2 VCR for different sectors from the CRA study for VENCorp

Sector	VENCorp study (2002) VCR ($/MWh)
Residential	$11,867
Commercial	$56,625
Agricultural	$54,782
Industrial	$18,531
VCR State (Total)	**$29,600**

The approach taken to evaluate the VCR in the residential sector was to survey a random sample of residential customers to identify substitutes they are willing to consider for reliable power. CRA notes a weakness of this approach is that 'surveys with residential customers asking them to comment on possible future actions can often be notoriously inaccurate'.[14] This may be due to the difficulty in providing numerical estimates of the inconvenience caused by the interruption.

To evaluate VCR for the commercial, industrial and agricultural sectors, customers were surveyed on actual economic losses incurred as a result of supply interruptions. CRA notes that a major drawback of this method is the time required to survey participants to collect cost data, which discourages participation and decreases the response rate. In addition, financial losses suffered by customers may not be easily identifiable.[15]

In its assessment, CRA comments on the short–comings of the study. It notes that:

- in the future, the use of a trade–off methodology, with built–in budget constraints would simulate more realistic estimates of customer 'willingness to pay' than direct questioning techniques
- the sample sizes used for the agricultural and large industrial sectors were very small and consequently, results may not be as robust as those obtained for other sectors. In addition, none of the cost data provided by respondents was audited and as such, may not have been well researched responses by participants

14 CRA, *Assessment of the Value of Customer reliability (VCR)*, Melbourne, December 2002, p. 12.
15 ibid., pp. 12–13.

- the study was limited to a sample within the Victorian region and is not easily comparable across states, given that methodologies may be different in other future studies that may be done

- implications of wide–area unplanned outages were not considered.[16]

The literature on survey techniques suggests that surveys of the kind undertaken by CRA may lead to overstatement and should be employed with caution.[17]

Despite these short–comings, VENCorp expressed confidence in the results of the study and now uses a VCR of $29,600 per MWh only in all state–wide regulatory test assessments.

The CRA study followed broadly similar methodologies to the earlier Monash study on the Victorian region, but returned large differences in values at the sectoral level. This includes a 1,505 per cent difference in the $/kWh VCR for residential customers, in relation to which, CRA states 'No definitive explanation can be given for this difference'.[18] These differences are outlined in table 2.3.

Table 2.3 Comparison of sector–level VCRs for Victoria ($/kWh)

Study	Residential	Commercial	Agricultural	Industrial
CRA	$11.88	$56.67	$55.49	$18.54
Monash	$0.74	$75.96	$96.19	$11.19
Difference (%)	**1,505%**	**-25%**	**-42%**	**66%**

CRA concludes that 'the fact that the final aggregated State–level values of VCR and VOLL [estimated in the Monash study] are almost identical is therefore more coincidental than necessarily reinforcing the original VOLL'.[19]

In its review of issues contained in the DJV submission, IES states:

> …it is reasonable to suspect that significant variability is attached to the application of the methodology and that it cannot be claimed that the value of customer reliability/lost load has been accurately determined.[20]

IES notes that the particular load shedding procedure practised in the region of interest may be more relevant to determining an appropriate value of USE than adjusting a composite number from another region for changes in sectoral weightings. It states that:

> On the basis that 1) load shedding priorities direct initial interruption to loads where there are no public safety issues and less economic loss and 2) to the extent to which it is believed that supply shortfalls might continue, interruptions will be managed, it might be concluded that in

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16 CRA, op. cit., pp. 44–46.

17 See for example *Report of the National Oceanic and Atmospheric Administration Panel on Contingent Valuation*, 11 January 1993 (www.darp.noaa.gov/library/pdf/cvblue.pdf).

18 CRA, op. cit., p. 5.

19 ibid., p. 6.

20 IES, *Review of Issues Contained in the DJV Submission on Directlink Economics*, 21 February 2006, p. 23.

> practice, the economic shortfall cost may be less than the average value of customer reliability estimated by the Monash and CRA studies.[21]

The AER notes the most recent determination by the Reliability Panel undertaken in March 2005 concluded that 'at present the current market price cap appears to be consistent with the delivery of sufficient capacity to meet the reliability standard. As a result the level of market price cap … should remain unchanged at $10,000 per MWh'.[22]

Directlink

In the context of Directlink, reliability benefits accrue in New South Wales, Victoria and South Australia. There is, however, limited information available on the value of USE outside Victoria.

As noted previously, Monash University provided a study for both VENCorp in 1997 (Victorian customers) and TransGrid (New South Wales customers) in 1998. The sectoral differences between the two regions, presented in table 2.4 below, ranges from 60 per cent to 180 per cent.[23]

Table 2.4 Comparison of Monash NSW and Victorian sector–level VCR ($kW/h)

Sector	Victoria	New South Wales	Difference (%)
Residential	0.74	0.49	66%
Commercial	75.96	52.37	69%
Agricultural	96.20	57.59	60%
Industrial	11.19	20.46	183%
Total	**28.89**	**20.56**	**71%**

This casts some doubt on the applicability of the value of USE, determined for the Victorian region, to NSW or other regions.

2.2.4 Conclusion

DJV proposed to use the 1999 version of the regulatory test. This specifies that a reasonable forecast of the value of energy to electricity consumers, as reflected in the level of VOLL, should be used in determining market benefits. In its Murraylink decision, the ACCC acknowledged that where an appropriate VCR has been determined for a region, it would not be inconsistent with the regulatory test to be used in the calculation of the estimated benefits to customers. The ACCC noted, however, that in the absence of an accurate value for VCR, the VOLL specified in the code should be used.

When the ACCC considered the application of the 1999 regulatory test to Murraylink it noted that it did not have a view as to the appropriateness of using VENCorp's

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21 ibid., p. 24.

22 NECA Reliability Panel, *VOLL and the Cumulative Price Threshold—Final Report*, Adelaide, March 2005, p. 7.

23 IES, op. cit., p. 22.

estimate in the context of the South Australian or Riverland regions.[24] The ACCC's application of the regulatory test employed scenarios including both $10,000 per MWh and $29,600 per MWh.

In the case of Directlink, reliability benefits arise in three States: NSW, Victoria and South Australia. The AER has no more material before it on the appropriate value of USE than the ACCC had when considering Murraylink. In particular, the AER cannot be satisfied that the estimate determined for Victoria is appropriate for other regions.

On this basis, the AER maintains its position taken in the draft decision. The AER considers that it is appropriate to use an approach that is consistent with the ACCC's application of the 1999 regulatory test in the Murraylink decision. Accordingly, the AER considers that values of $10,000 per MWh and $29,600 per MWh should both be employed when applying the regulatory test and estimating the economic benefits of Directlink.

This approach is further supported by uncertainty surrounding the estimated value of USE prepared for VENCorp and the potential for it to overstate the actual value of USE. The use of both values provides a degree of confidence that the scenarios employed in the regulatory test will span the credible range.

2.3 Use of the median to estimate market benefits

2.3.1 Issues raised in submission

DJV submitted that the population mean is more appropriate for determining the economic value (EV) than the population median. DJV stated that the mean of the sample is more statistically valid than the median because:

- the use of the mean minimises the risk of estimation whereas the use of the median does not
- sampling for the mean has a lower error rate than sampling for the median.[25]

The submission from the South Australian Minister for Energy Hon Patrick Conlon MP, stated the need to accurately determine the benefits to customers of providing a transmission network service.[26]

2.3.2 Draft decision

Under the regulatory test framework, the AER employed six scenarios. These scenarios were deliberately chosen to span the range of credible market outcomes. They do not represent a random selection from the population of possible outcomes.

The estimated gross market benefits span a large range from $128.9 million (under a value of USE of $10,000 per MWh with low demand growth) to $257.3 million (under a value of USE of $10,000 per MWh with high demand growth).[27]

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[24] ACCC, *Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue*, Canberra, 1 October 2003, p. 86.

[25] DJV, *Submission*, p. 18.

[26] Hon Patrick Conlon MP, Government of South Australia, 31 December 2005.

In the draft decision it was considered that selecting the scenario with the lowest EV for setting the asset value would provide the highest degree of confidence that the market benefits can be achieved.

The AER, however, concluded that the best balance to determine an EV is to use the measure of central tendency. The median was deemed the most suitable statistical measure for providing a single value given the large range and skewed distribution of the estimated market benefits. This was consistent with the principles set out in the regulatory test and ensures an acceptable balancing of the interests of transmission network owners and users.

2.3.3 Considerations

The AER sought advice from NERA Economic Consulting (NERA) on this issue. In its report, NERA stated that the AER's adoption of the sample median is appropriate in this context. NERA made the following observations about DJV's submission:

- if the AER is attempting to estimate the population median, then the arguments presented in the DJV submission do not support the use of the sample mean as the best estimate. The fact that the sample mean has a lower error in estimating the population mean does not imply that it has a lower error in estimating the population median. If the AER wishes to measure the population median then the statistic it should choose is the statistic that has the lowest sampling error in measuring the median

- the sample mean is likely to be an upward biased estimate of the population mean because high and low demand scenarios are likely to be less probable than the medium demand scenarios and because the relationship between demand and economic value is skewed.

NERA also stated that an approach consistent with the construction of the regulatory test is likely to be desirable and that this suggests adoption of the sample median.[28]

The AER considers it is important for the valuation methodology employed for Directlink to be consistent with the principles underlying the regulatory test.

The relevant limb of the regulatory test specifies that an augmentation satisfies the test if:

> …the augmentation maximises the net present value of the market benefit.

The test goes on to state:

> …a proposed augmentation maximises the market benefit if it achieves a greater market benefit in most (although not all) credible scenarios.[29]

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[27] AER, *Draft Decision*, p. 129.

[28] NERA, *The measure of central tendency used to set Directlink's regulatory asset base*, Melbourne, 22 February 2006, p. 8.

[29] ACCC, *Regulatory Test for New Interconnectors and Network Augmentations*, 15 December 1999, pp. 21-22.

Neither Directlink, nor any other alternative project satisfied the regulatory test. The alternative that came closest to satisfying the regulatory test was alternative 2. However, alternative 2 did not satisfy the regulatory test because its net market benefits were positive in only two of the six credible scenarios. If alternative 2 had satisfied the regulatory test, the asset value for Directlink would have been capped at the capital cost of alternative 2.

It was then necessary to adopt an alternative asset valuation methodology. The AER decided that it would employ a method that valued Directlink according to the benefits it provided to the market. However, because there was uncertainty about the market circumstances that were likely to arise, it was decided to set the asset value with reference to a range of scenarios rather than a single scenario.

Setting the asset value of Directlink with reference to the mean of the gross benefits of a number of credible scenarios would not be consistent with the application of the regulatory test. The regulatory test requires positive net market benefits in most scenarios. The mean value of the net market benefits is irrelevant. If the AER gave weight to the mean of the gross benefits it would be possible to generate a higher asset value than if the regulatory test had been satisfied.

This was the case for Directlink. The total life cycle costs of alternative 2 were \$170.0 million, while the mean value of the gross market benefits of Directlink was \$176.5 million. If the asset value had been set with reference to the mean of the gross market benefits, the asset value for Directlink would have exceeded the value that would have been set if the regulatory test had been satisfied by alternative 2. This would be a perverse outcome.

This anomaly is avoided by setting the asset value with reference to the median of the gross market benefits. The median is more consistent with the principles underlying the regulatory test because a project cannot satisfy the regulatory test unless the median net economic value is positive.

2.3.4 Conclusion

The AER maintains its position taken in the draft decision. It has estimated the EV of Directlink with regard to the median of the gross market benefits in the six credible scenarios.

2.4 Understatement of benefits

2.4.1 Issues raised in submissions

DJV stated that there are additional benefits that have not been included in the analysis. As a result the benefits set out in the draft decision could under estimate the actual benefits. These benefits include competition benefits and other types of technical support.

2.4.2 Considerations

The AER sought advice from IES on the magnitude of any potential competition benefits. IES acknowledged that competition benefits would be expected to be positive. However, in the absence of detailed modelling, the value of any such benefits could not be determined. The value of competition benefits vary depending on individual circumstances. In some cases, competition benefits can be quite small, while in other cases they can be significant. IES stated that without undertaking modelling of such benefits it is not possible to infer whether or not the estimated benefits are conservative.

In regard to DJV's claims that other technical benefits might also increase the actual benefits, the AER sought advice from CHC Associates. CHC Associates advised that any such benefits have already been captured:

> The ability of Directlink to raise the transient stability limit in a southerly direction has been fully captured within the increase in power transfer capability that was used in the market benefits study. There is no physical mechanism for increasing the transient stability limit by more than Directlink's capacity (as also constrained by the neighbouring networks). Nor would an increase in transient stability in a northerly direction have any effect, because transfer in this direction is limited to a lower level by the thermal limits of lines.
>
> Voltage support is only effective very close to Directlink's terminals, and is used to support the power transfers that have been assumed to take place over Directlink. There is no other voltage control benefit available.
>
> Oscillatory stability is controlled by devices that are located close to the paths of the AC interconnectors, in this case QNI. However any control scheme that attempted to act upon Directlink would be ineffective because it would be negated by a counter–power flow though QNI itself. Hence there is no prospect of Directlink having any beneficial effect.[30]

Having taken into account the advice of its consultant, the AER is of the view that all the technical benefits of Directlink have been fully incorporated in the market benefits modelling. Therefore, there is no basis to conclude that the market benefits are understated.

2.4.3 Conclusion

IES acknowledged that competition benefits would be expected to be positive. However, in the absence of detailed modelling, the value of any such benefits could not be determined. The value of competition benefits vary depending on individual circumstances. In some cases, competition benefits can be quite small, while in other cases they can be significant. In the absence of further evidence it is not possible for the AER to determine that the market benefits modelled by DJV understate the true value. The technical benefits of Directlink have been fully incorporated.

2.5 Potential deferral of line 966

2.5.1 Issues raised in submissions

DJV claimed that a second transformer at Molendinar could be installed for the summer of 2006–07 to provide additional capacity to flow south across Directlink into NSW and avoid the need to upgrade line 966.[31]

Powerlink confirmed the installation of a second Molendinar transformer, but advised that it is unable to be operated in service over the summer of 2006–07 due to technical fault level restrictions in Energex's network. Therefore it will not provide

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30 Email advice to the AER, 3 February 2006.
31 DJV, *Letter to the AER*, Port Macquarie, 21 September 2005, p. 2.

any additional network capacity to allow Directlink to flow south at higher levels in 2006–07.[32]

TransGrid confirmed Powerlink's assessment of its network capacity and the uncertainty about the capacity available for southern flows across Directlink. TransGrid issued a regulatory test report on a new small transmission network asset in November 2005. It considered that network support from Directlink is not feasible. TransGrid recommended that the only feasible option is to proceed with uprating line 966 which will provide increased reliability of supply to north eastern NSW.[33]

Country Energy noted that TransGrid is proceeding with the uprating of line 966 and acknowledged the potential benefits that may be delivered by this work.[34]

2.5.2 Draft decision

Based on material the AER received prior to making its draft decision there was significant uncertainty about Directlink's capacity to flow south in the summer of 2006–07. Consequently, the AER considered it reasonable for TransGrid to minimise the risk to its network in the summer of 2006–07 by uprating line 966 (132 kV Armidale to Koolkhan). Accordingly, no deferral benefit from the uprating of line 966 was attributed to Directlink.

Further information on the issue was received from Country Energy late in the development of the draft decision. It was proposed that further consultation would be undertaken following release of the draft decision.[35]

2.5.3 Considerations

It is likely that the installation of a second transformer by Powerlink, without advancement of other investments, would not provide any additional capacity to flow south across Directlink over the period of 2006–07. The advancement of other investments relate particularly to Powerlink's purchase of a replacement spare transformer and augmentations to the Energex network. As a result of this, the AER retains its original position that it is reasonable for TransGrid to minimise the risk to its network by uprating line 966 to alleviate its network reliability problems and therefore no deferral of the uprating is attributed to Directlink.

2.5.4 Conclusion

Information received by the AER supports the draft decision to disallow any deferral benefit of line 966. As such, no deferral of the uprating of line 966 is attributed to Directlink.

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32 Powerlink, *Capacity in Southern Queensland Network During Summer of 2006-07*, 12 December 2005, p. 2.

33 TransGrid, *Directlink Draft Decision—Benefits of Deferring Transmission Augmentations,* 7 December 2005, p. 1.

34 Country Energy, *Directlink Draft Decision*, 7 December 2005, p. 1.

35 AER, *Draft Decision*, p. 81.

2.6 Debt margin

2.6.1 Issues raised in submissions

DJV stated that since the lodgement of its application in September 2004 new research has indicated the estimation methodology employed by CBASpectrum understates the yields (downward bias) on low rated, long dated corporate bonds.[36] The TNOs also cited a study by NERA Economic Consulting and decisions by the Western Australian Economic Regulation Authority and the Essential Services Commission of Victoria, which support the claim that the CBASpectrum yields are understated, and the data should not be relied upon without appropriate adjustments.[37]

On this basis, DJV submitted that either the AER add around 25 basis points to any proposed debt margin based on information from the CBASpectrum service or base its estimates of a benchmark debt margin upon information from the Bloomberg service. The TNOs also stated that the AER should add around 25 basis points to estimates obtained from the CBASpectrum database.

2.6.2 Draft decision

The draft decision did not accept DJV's proposal to adopt the long term average of the debt margin predicted by the CBASpectrum service to provide a benchmark debt margin of 1.5 per cent. It was considered more appropriate to use the 10 day moving average benchmark debt margin over the government bond yields, for A rated corporate bonds with a term of 10 years, which was 84 basis points based on CBASpectrum data.[38]

2.6.3 Considerations

To investigate DJV's claims the AER, in conjunction with the Allen Consulting Group (on behalf of DJV), undertook a comparison of the estimated average daily fair yields for corporate bonds of various credit rating and maturity over the period of 1–30 November 2005 from the Bloomberg and CBASpectrum databases.[39] It was found that there were differences between the estimated average yields from the Bloomberg and CBASpectrum databases.

In addition, the average daily fair yields for all bonds with an A credit rating, with a maturity of 10 years, from 1 January – 31 December 2005 were reviewed. It was found that differences existed between the estimates from both databases. These differences, however, varied depending on the credit rating, term to maturity of the bond and timeframe over which the yields were averaged.

The Allen Consulting Group provided an additional submission that concluded:

> …in terms of the accuracy of estimating individual bonds for a given ratings category in the market, the Bloomberg service tends to provide significantly closer estimates of actual bond yields…If it is considered that the bonds included by Bloomberg to estimate the fair yield for the A rated category are representative of the bond yield being benchmarked….then the

36 DJV, *Submission*, p. 22

37 Joint Transmission Network Owners, op. cit., p.1.

38 AER, *Draft Decision*, p. 216.

39 The period of 1-30 November 2005 was used because it was a stable period, with estimates being representative of typical average yields.

> Bloomberg estimates should be applied when they provide a closer estimate of actual bond yields than do the CBASpectrum fair yields.[40]

The key difference between the two databases seems to be whether constraints are imposed on the yield curves. In the CBASpectrum model, fair yield curves will not cross. That is, as one moves down the credit spectrum the higher risk of default is compensated by higher yields. By contrast Bloomberg extrapolates from the data and its resulting yield curves for different credit ratings can intersect. This may be one cause of differences between the estimates of debt margins for particular types of bonds.

The AER notes that Bloomberg and CBASpectrum are both respected providers of financial information to the market. However, the AER's analysis indicates that Bloomberg appears to provide an estimate of A rated, long term fair yields (debt margins) which are more consistent with the observed yields of similarly rated actual bonds. Therefore, in this instance, it is reasonable for the AER to use Bloomberg data for determining the benchmark debt margin for DJV.

2.6.4 Conclusion

The AER will use the Bloomberg data service for determining the relevant benchmark debt margin for DJV (see section 3.3).

2.7 Regulatory control period

2.7.1 Issues raised in submissions

Metgasco argued that DJV should not be allowed to have a 10 year regulatory period. It contended that the argument that an entity should receive regulated revenue over a 10 year period because it will save the cost of going through a regulatory reset in 5 years has no merit and could result in perverse outcomes in a market subject to significant change over the regulatory period.[41]

Minister Conlon stated that a 10 year regulatory reset period is 'too long and prevents the revisiting of the regulatory asset base within a reasonable period'.[42]

2.7.2 Draft decision

In its 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. In determining the appropriate length of the regulatory period in the draft decision, the AER noted that it 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.[43]

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40 ACG, *'A' rating debt margin differential between Bloomberg and CBASpectrum–Memorandum*, 21 February 2006.

41 Metgasco Ltd, *Comment on Conversion Decision*, 9 December 2005, pp. 2-3.

42 Hon Patrick Conlon MP, Government of South Australia, 31 December 2005.

43 AER, *Draft Decision*, p. 156.

2.7.3 Considerations

The AER notes Metgasco's arguments for not providing a 10 year regulatory period. DJV, however, has limited opportunity to substantially reduce its costs because there is no allowance for capital expenditure (capex) and only an efficient operating expenditure has been allowed. In addition, the AER does not expect that a regulatory reset for DJV would involve another regulatory test assessment to adjust its asset value.

In respect of the suggestion that the length of the regulatory period prevents the revisiting of the RAB, the AER is of the view that substantial caution should be exercised when contemplating the revaluation of assets. In particular, there is potential for revaluation decisions to create uncertainty for investors and reduce investment in markets where substantial, ongoing investment is necessary. The AER is of the view that once an asset base has been set it generally should only be adjusted for inflation, disposals, depreciation and capex, and should not be revalued consistent with chapter 6 of the National Electricity Rules.

In addition, the AER has carefully examined the reliability of Directlink and considers there is a reasonable likelihood that DJV will be able to provide a satisfactory level of reliability on 120 MW.

2.7.4 Conclusion

The AER considers that DJV's request for a 10 year regulatory control period is justified.

2.8 Service standards

2.8.1 Issues raised in submission

DJV largely agreed with the service standards scheme set out in the draft decision. However, it proposed a number of minor amendments. These changes included:

- the removal of the definition of the unit of measure due to redundant and potentially inconsistent wording
- alterations to the service standards factor (s-factor) and formula tables to more accurately reflect circuit availability as a percentage
- clarification that the incentive scheme did not include unregulated assets
- a defined timetable for annual performance reporting.

DJV also provided the AER with a number of worked examples based on the draft service standards framework and proposed a number of definitions to be attached to the service standards scheme.

2.8.2 Considerations

The AER is not convinced of DJV's argument that the wording of the definition of the unit of measure is redundant and inconsistent, and should therefore be removed. Indeed, the AER considers the inclusion of the present definition as necessary because it maintains consistency with the service standards guidelines.

The AER agrees with DJV's proposed changes to the s-factor and formula tables to reflect circuit availability as a percentage. This alteration recognises the appropriate unit of measure for circuit availability and results in an accurate formulaic representation of DJV's performance targets. The service standard scheme set out in appendix B has been adjusted accordingly.

The AER considers the draft decision provides sufficient clarity in regards to the treatment of unregulated assets in the incentive scheme. Within the draft decision unregulated assets were clearly listed as exclusions from the service standards regime.

In relation to the timetable for annual performance reporting, the AER does not propose to incorporate DJV's timetable and task list into the service standards scheme. The AER considers that to maintain consistency with the process applied to other TNSPs and flexibility to respond to the organisational needs of all parties, the timetable for annual compliance should be decided on an annual basis by agreement between the AER and DJV with due regard for the requirements of the service standards guidelines and pricing imperatives.

DJV also included a number of definitions in its submission. As set out in table 2.5, the AER has considered these definitions and does not propose to include the following definitions as a part of the service standards regime for the reasons outlined.

Table 2.5 DJV's proposed definitions

DJV's proposed words for definition	Reason
AEMC, AER, Disconnection	Defined in the National Electricity Rules.
Authority, Circuit, Third Party System, Unavailability (or Total Capacity Unavailable Hours)	Defined in the service standards guidelines.
Peak Period, Off–peak Period	Outlined in table B.1 of appendix B.
MAR, TNSP, Unit, Year	Unnecessary or already defined in this decision.
Available circuit hours, Interruption, SCADA, Works	Not referred to in DJV's service standards incentive scheme.

In relation to the definitions of Excluded and Force Majeure events, the AER provided consideration of DJV's proposed definitions in its draft decision. DJV has provided no new information for the AER to consider and the definitions set out in the draft decision have been maintained in this decision.

DJV also proposed the inclusion of definitions for Forced outage events and Scheduled outage events. The AER considers that the inclusion of these definitions to be appropriate to provide greater clarity of events relating to the performance measures. DJV proposed the following definitions:

> Forced outage event means the actual or imminent occurrence of an event, other than an Excluded Event, that poses or has the potential to pose an immediate threat to the safety of

> persons, hazard to any equipment or property or a threat to power system security, and that results in the Circuit being not Available.
>
> Scheduled outage event means the actual occurrence of an event, other than an Excluded event or a Forced Outage Event, which results in the Circuit being not Available.

The AER, having taken into account the advice of its consultant (CHC Associates), is of the view that a more accurate definition of a Forced outage event and a Scheduled outage event is as follows:

> Forced outage event means the urgent and unplanned reduction in the real power transfer capability of Directlink that occurs as a necessary consequence of the actual or imminent occurrence of an event that poses, or has the potential to pose, an immediate threat to the safety of persons, hazard to any equipment or property or a threat to power system security.
>
> Scheduled outage event means the actual planned reduction in the real power transfer capability of Directlink that does not occur as a result of a forced outage event.

It should be noted that the AER's proposed definitions do not specify excluded events. This is to ensure consistency with the reporting requirements outlined in section 4.2 of the service standards guidelines and clear treatment of exclusions in relation to TNSP performance. The guidelines require a TNSP to report actual performance to the AER *before* any events are excluded from a certain measure. Only after this point may the TNSP apply to the AER for exclusions to be allowed. The AER considers that its proposed definitions more appropriately recognise excluded events as factors affecting performance measures ex post, rather than ex ante as contained in DJV's proposal.

DJV proposed to clarify circuit availability in relation to the number of units which constitute the circuit. The AER has included a definition and a basic example in appendix B to show the way in which circuit availability should be measured according to a capacity weighting.

DJV's example calculations showing the outcomes of the proposed service standards regime are broadly consistent with the way in which the performance incentive scheme would operate. The AER proposes, however, to correspond with DJV prior to the commencement of its first service standards review to enable further refinement of these reporting processes.

2.7.3 Conclusion

The AER considers the following adjustments to the draft decision to be appropriate:

- to amend the s-factor and formula tables as outlined in the draft decision to reflect circuit availability as a percentage
- to insert definitions of a Forced outage event and a Scheduled outage event
- to further clarify the measurement of circuit availability according to a capacity weighting.

Appendix B details the AER's conclusion on the performance incentive scheme to apply as part of DJV's revenue cap.

2.9 Presentation of the final decision

2.9.1 Issues raised in submission

For the purposes of achieving regulatory and commercial certainty, DJV submitted that the decision can be described in clearer terms by setting out the following elements:

1. The maximum allowed revenue for year 1 (2005–06).

2. The X smoothing factor, which is a percentage that determines the rate by which the base annual revenue falls in real terms, to be determined in accordance with the building block revenue requirement.

3. The revenue formula for adjusting the maximum allowed revenue.[44]

2.9.2 Considerations

DJV's submission has highlighted that improvements can be made to the presentation of the revenue cap decision. Consequently, the revenue cap decision which is set out in chapter 4 has been adjusted as follows:

- the formulae for the revenue adjustment have been consolidated

- some definitions have been revised

- minor typographical errors were corrected.

2.9.3 Conclusion

The AER has made minor adjustments to the presentation of the revenue cap decision to improve its clarity and this is set out in chapter 4. No substantive adjustments have been made.

2.10 Subtraction of network payments

2.10.1 Issues raised in submission

DJV stated that there is no need for the network support payments over the 2005–06 summer period to be subtracted from Directlink's estimated market benefits for the Queensland augmentation deferral, and in turn, be subtracted from its asset value.

2.10.2 Draft decision

The draft decision did not subtract any expected network support payments from Directlink's estimated market benefits. The AER, however, noted that when Directlink converts to a prescribed service after payments have been made to DJV under the network support agreement, then those payments should be subtracted from the estimated deferral benefit for the Queensland augmentation. This would ensure customers do not pay twice for that deferral.

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44 DJV, *Submission*, p. 27.

2.10.3 Considerations

It is appropriate to not subtract the network support payments from Directlink's estimated market benefits. While the AER has estimated the benefit of Directlink deferring the Queensland augmentation for one year (2005–06), DJV will not be receiving a regulated revenue allowance for the entire 2005–06 financial year. Instead its revenue will be adjusted on a pro rata basis according to the actual date of conversion (see section 4.3.1). Prior to conversion, DJV will earn revenue for the provision of network support as a market network service. DJV will then only receive a proportion of the 2005–06 regulated revenue after conversion. As such, customers would not be paying twice for the deferral of the Queensland augmentation.

2.10.4 Conclusion

The AER has not subtracted any network support payments from Directlink's estimated market benefits.

2.11 Issues not raising substantive new material

Some submissions contained several issues which were considered by the AER in its draft decision and which did not raise substantive new material. Accordingly, it is appropriate for the AER to maintain the conclusions set out in the draft decision. These issues included:

- the version of the regulatory test
- selection of the alternative projects (inclusion of alternative 5 as an alternative project)
- PB Associates' promotion of Port Macquarie deferral
- the long run marginal cost bidding cases for modelling the interregional benefits
- the NSW–northern NSW intraregional constraint
- Directlink's operating and maintenance costs
- conversion to a prescribed service.

3 Issues requiring final resolution

3.1 Introduction

The draft decision left open a number of issues for final resolution and which were not raised in submissions. These issues are set out below.

3.2 Reliability of Directlink

3.2.1 Draft decision

The AER's draft decision noted Directlink's history of poor reliability and the program of reliability projects being undertaken by DJV. In applying the regulatory test, a reliability of 99 per cent for 120 MW (that is, two out of three circuits) was assumed for the purposes of estimating the market benefits offered by Directlink.

Because of the uncertainty about whether Directlink can achieve the reliability required to provide the market benefits, the AER concluded that the estimated market benefits should be regarded as an upper bound. In addition, the cost of the upgrades to improve Directlink's reliability was excluded from the revenue cap because 99 per cent reliability for 120 MW was assumed for the determination of the market benefits.[45]

3.2.2 Considerations

Since the release of the draft decision, the reliability of Directlink has been further assessed. In December 2005, the AER requested DJV to provide an update on the status of its program of reliability projects. DJV responded in January 2006, stating that the design and implementation of the projects have involved working extensively with Directlink's manufacturer to resolve a number of technical matters. This has taken longer than expected throughout 2005. While some projects were largely completed and have yielded material improvements to Directlink's reliability, the remaining projects are expected to be completed throughout 2006. DJV 'remains committed to implementing cost effective measures to improve Directlink's reliability'. It noted that for 2005, Directlink's forced outage availability was 87 per cent for three circuits.

DJV also provided a spreadsheet calculating the number of hours that 1, 2 and 3 circuits had outages at the same time. The spreadsheet demonstrates that in 2005, Directlink achieved 96.5 per cent forced availability for 120 MW. Further, the majority of Directlink's 3–unit outages were caused by what appears to be excluded events. For example, there was a 3–unit outage on 7 July 2005 that was caused by catastrophic storm damage. Had this event not taken place or not been counted, Directlink would have achieved 99.7 percent forced availability for 120 MW and 90.2 per cent for 180 MW. In the recent period from 21 December 2005 to date, Directlink's availability has been 99 per cent for 180 MW and 100 per cent for 120 MW. The AER has reviewed these calculations and they appear to be reasonable.

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45 AER, *Draft Decision*, p.184.

In February 2006, DJV submitted additional material on its reliability program and has committed to a program of project upgrades that will continue to improve Directlink's reliability for all three circuits:

> The Directlink Joint Venturers will be taking seriously any direct or implied rules obligation to minimise the frequency and duration of Directlink's outages. We are committed to the implementation of more reliability projects that should consolidate Directlink's reliability during 2006.[46]

DJV also indicated that it would be entering a connection agreement with Country Energy which would impose reliability obligations on Directlink. The terms of this obligation in the proposed agreement is imprecise and there is uncertainty about whether it would require a level of reliability consistent with the assumptions underlying the benefit calculation. However, if Directlink does not achieve the assumed level of reliability this would place the reliability of the Country Energy network at risk. This would expose Country Energy to potential action under its licensing conditions. It would therefore be expected that Country Energy would take an active interest in ensuring that Directlink achieves a satisfactory level of reliability.

The draft decision stated that capital allowances would not be provided to Directlink for work undertaken to achieve the reliability assumed in the benefit calculations—that is 99 per cent for 120 MW. The AER considers that this approach remains appropriate. If capital allowances were provided for achieving the minimum level of reliability, DJV would be compensated twice because the RAB is based on benefits that assume the minimum level of reliability.

The maximum allowed revenue (MAR) for Directlink does not include any allowance for capital works as none has been proposed by DJV. To the extent, however, that DJV undertakes prudent works to improve its reliability beyond the minimum level it may be appropriate to include the cost of these works into the capital base at the next revenue reset.

3.2.3 Conclusion

The latest reliability data suggests that Directlink is currently operating at a level that is consistent with the assumptions employed in the market benefit calculations. The data, however, covers a short period and the reliability projects are not yet complete. Consequently, there is still some uncertainty about Directlink's future reliability.

On balance the AER is of the view that Directlink's current reliability is most likely consistent with the assumptions employed in the estimation of the market benefits. In the event that this is not the case, there are three factors to suggest that Directlink will undertake further corrective action. First, DJV has provided a commitment in correspondence to improve Directlink's reliability. Second, DJV will have a reliability obligation in its connection agreement with Country Energy and Country Energy will have an incentive to ensure that adequate reliability is provided by Directlink. Third, the service standards scheme for DJV (see appendix B) will provide financial incentives to achieve a higher level of reliability, which will be

[46] DJV, *Letter to the AER re: Application for Conversion to a Prescribed Service and Maximum Allowable Revenue to June 2015*, 21 February 2006, p. 3.

beneficial to the market as a whole. As such, the AER maintains its position in the draft decision.

3.3 Updating the WACC

3.3.1 Draft decision

In its draft decision, the AER noted that it would update the WACC for the prevailing market bond yields when finalising its decision because some parameters vary over time according to market conditions.

3.3.2 Considerations

The parameters which require updating are:

- the risk–free rate
- the debt margin
- the forecast inflation.

As discussed in section 2.6, two submissions took issue with the estimation of the debt margin of the proposed WACC. No other submissions commented on the aspect of updating the WACC. As such, the WACC parameters have been updated for the prevailing market bond yields to reflect the required changes.

3.3.3 Conclusion

Risk–free rate

As at the date of this decision, the 10 day moving average for the 10 year nominal Commonwealth bond rate results in a proxy risk–free rate of 5.32 per cent (effective annual compounding rate).[47]

Forecast inflation

The forecast inflation rate is calculated by the difference between the nominal bond rate and the inflation indexed bond rate, as determined using the Fisher equation.[48] For this decision, the AER forecasts inflation of 2.97 per cent.

Debt margin

As at the date of this decision, the 10 day moving average benchmark debt margin over the government bond yield, for A rated corporate bonds with a term of 10 years, is 100 basis points.[49] Combined with the nominal risk–free rate of 5.32 per cent, it provides a nominal cost of debt of 6.32 per cent.

Table 3.1 sets out the individual parameters of the WACC adopted for this decision. The AER considers that a post–tax nominal return on equity of 11.32 per cent, combined with a pre–tax nominal cost of debt of 6.32 per cent, which equates to a

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47 Source: Reserve Bank of Australia.

48 As at the date of this decision, the 10 day moving average for the 10 year inflation indexed bond rate results in a proxy real risk–free rate of 2.28 per cent (annual compounding rate).

49 Source: Bloomberg.

nominal vanilla WACC of 8.32 per cent, provides an appropriate cost of capital for DJV.

Table 3.1 Comparison of cost of capital parameters

Parameter	DJV's proposal	The AER's draft decision	The AER's decision
Nominal risk–free interest rate (r_f)	5.54%	5.50%	5.32%
Real risk–free interest rate (rr_f)	2.94%	2.64%	2.28%
Expected inflation rate (f)	2.53%	2.79%	2.97%
Debt margin (d_m)	1.50%	0.84%	1.00%
Cost of debt ($r_d = r_f + d_m$)	7.04%	6.34%	6.32%
Market risk premium ($r_m - r_f$)	6.00%	6.00%	6.00%
Gearing (D/V)	60%	60%	60%
Value of imputation credits γ	50%	50%	50%
Asset beta (β_a)	0.45	na	na
Debt beta (β_d)	0.00	na	na
Equity beta (β_e)	1.13	1.00	1.00
Nominal post–tax return on equity	12.32%	11.50%	11.32%
Post–tax nominal WACC	na	6.79%	6.74%
Pre–tax real WACC	na	5.93%	5.62%
Nominal vanilla WACC	**9.16%**	**8.40%**	**8.32%**

na Not available.

3.4 Pass-through mechanism

3.4.1 Draft decision

The draft decision noted that some specific dates and the quantum of the materiality threshold (based on one per cent of the TNSP's average MAR for a financial year) would need to be inserted in the pass-through mechanism at the time of finalising the decision.

3.4.2 Considerations

No issues were raised by interested parties on the draft pass-through mechanism. As such, the pass-through mechanism in appendix C of this decision has been updated to reflect the required changes without substantive amendment.

3.4.3 Conclusion

The pass-through mechanism in appendix C has been updated to insert specific dates and to set the materiality threshold at $126,000, based on one per cent of DJV's average MAR for a financial year.

4 Decision

4.1 Introduction

Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision. This chapter contains the AER's decision on DJV's application for conversion of Directlink to a prescribed service and the calculation of a maximum allowed revenue (MAR) to take effect from the date of conversion to 30 June 2015. The remainder of this chapter sets out:

- the AER's conversion decision (section 4.2)
- the AER's revenue cap decision (section 4.3).

4.2 The conversion decision

Under clause 2.5.2(c) of the National Electricity Code (code), the determination of whether a market network service can be converted to a prescribed service is at the discretion of the AER.

As set out in chapter 4 of the draft decision, the AER considers that Directlink is able to satisfy the definition of a prescribed service. As such, the AER's decision under clause 2.5.2(c) of the code is that Directlink's network service will be a prescribed service, on and from the time it ceases to be classified as a market network service.

4.3 The revenue cap decision

Clause 2.5.2(c) of 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 determine the revenue cap (or MAR) in accordance with chapter 6 of the code. The MAR set out below follows the draft decision except where adjustments are indicated in this final decision.

The MAR for each year of the regulatory period is determined in accordance with the accrual building block approach:

Revenue	=	return on capital + return of capital + opex + tax
	=	(WACC x WDV) + D + opex + tax

where:

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.

This revenue allowance can vary over the regulatory period. To avoid such variation, the revenues are smoothed within a regulatory period while maintaining the principle of cost recovery under the building block approach. This is done by allowing some cost recovery to be diverted to adjacent years within the regulatory period in such a way that the net present revenue (NPV) of the smoothed revenues is equal to the NPV of the unsmoothed (lumpy) revenues. That is, a smoothed profile of the TNSP's allowed revenue (AR) is determined for the regulatory period under the CPI – X mechanism.

The MAR for the first year is set equivalent to the allowed revenue (AR) for the first year of the revenue cap:

$$\text{MAR}_1 = \text{AR}_1$$

where:

MAR_1 = the maximum allowed revenue for year 1

AR_1 = the allowed revenue for year 1.

The MAR for the subsequent years of the regulatory period is adjusted annually based on the previous year's AR. That is, the subsequent year's AR is determined by adjusting the previous year's AR for actual inflation and the X factor:

$$\text{AR}_t = \text{AR}_{t-1} \times (1 + \Delta\text{CPI}) \times (1 - \text{X})$$

where:

AR = the allowed revenue

t = time period/financial year (for $t = 2, 3 \ldots 10$)

ΔCPI = the annual percentage change in the Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in year $t - 2$ to March in year $t - 1$

X = the smoothing factor.

The MAR is then determined by adding to (or deducting from) the AR the service standards incentive (or penalty) and any allowed pass-through amounts (see table 4.1 for timing of calculating the AR and financial incentive):

$$\text{MAR}_t = \text{(allowed revenue)} + \text{(financial incentive)} + \text{(pass-through)}$$

$$= \text{AR}_t + \left(\frac{(\text{AR}_{t-1} + \text{AR}_{t-2})}{2} \times \text{S}_{ct} \right) + \text{P}_t$$

where:

MAR = the maximum allowed revenue

AR	=	the allowed revenue
S	=	the service standards factor determined in accordance with the performance incentive scheme set out in appendix B
P	=	the pass-through amount that the AER has determined in accordance with the pass-through mechanism set out in appendix C
t	=	time period/financial year (for *t* = 2, 3…10)
ct	=	time period/calendar year (for *ct* = 3, 4…10).

Table 4.1 Timing for calculating AR and the financial incentive

t =	Allowed revenue (financial year)	*ct* =	Financial incentive (calendar year)
-	1 July 2005 – 30 June 2006	-	Not applicable
2	1 July 2006 – 30 June 2007	-	Not applicable
3	1 July 2007 – 30 June 2008	3	1 January 2006 – 31 December 2006[1]
4	1 July 2008 – 30 June 2009	4	1 January 2007 – 31 December 2007
5	1 July 2009 – 30 June 2010	5	1 January 2008 – 31 December 2008
6	1 July 2010 – 30 June 2011	6	1 January 2009 – 31 December 2009
7	1 July 2011 – 30 June 2012	7	1 January 2010 – 31 December 2010
8	1 July 2012 – 30 June 2013	8	1 January 2011 – 31 December 2011
9	1 July 2013 – 30 June 2014	9	1 January 2012 – 31 December 2012
10	1 July 2014 – 30 June 2015	10	1 January 2013 – 31 December 2013

1. Conversion of Directlink is expected after 1 January of this calendar year. Therefore the financial incentive calculation will be on a pro rata basis according to the number of days remaining after conversion in the calendar year (that is, less than 365 days).

4.3.1 Maximum allowed revenue

As explained in chapter 11 of the draft decision, the AER determined the depreciated value of DJV's opening asset base to be $116.68 million at 1 July 2005. The opening depreciated asset value does not include any additional forecast capex over the regulatory period of 10 years.

Based on the remaining life of the asset, DJV's asset base over the regulatory period is shown in table 4.2.

Table 4.2 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	117.0	117.3	117.5	117.5	117.5	117.4	117.2	116.8	116.3
Return of capital	–0.3	–0.3	–0.2	0.0	0.0	0.1	0.2	0.4	0.5	0.6
Closing asset value	117.0	117.3	117.5	117.5	117.5	117.4	117.2	116.8	116.3	115.7

Based on its assessment of the building block components and using the post–tax revenue model (PTRM), the AER has determined the appropriate unsmoothed revenue for DJV. It proposes an unsmoothed revenue allowance that increases from $11.75 million in 2005–06 to $13.44 million in 2014–15, as shown in table 4.3.

Table 4.3 The AER's 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	9.71	9.74	9.76	9.77	9.78	9.78	9.77	9.75	9.72	9.68
Return of capital	–0.34	–0.26	–0.17	–0.08	0.02	0.12	0.24	0.35	0.48	0.61
Operating expenses	2.05	2.11	2.17	2.23	2.30	2.60	2.68	2.50	2.57	2.65
Taxes payable	0.67	0.71	0.74	0.78	0.81	0.85	0.89	0.93	0.96	1.00
Franking credits	–0.34	–0.35	–0.37	–0.39	–0.41	–0.43	–0.44	–0.46	–0.48	–0.50
Unsmoothed revenue	11.75	11.94	12.13	12.32	12.50	12.93	13.12	13.07	13.25	13.44

[1] DJV's revenue allowance for 2005–06 will be adjusted on a pro rata basis according to the actual date of conversion (see below).

From this unsmoothed revenue, an NPV of $82.80 million was calculated for the regulatory period. Based on this NPV, the AER has determined a smoothed AR for DJV that increases from $11.75 million in 2005–06 to $13.59 million in 2014–15, as shown in table 4.4 (based on a smoothing X factor of 1.31 per cent).

Table 4.4 The AER's decision on forecast smoothed allowed revenue ($ million, nominal)

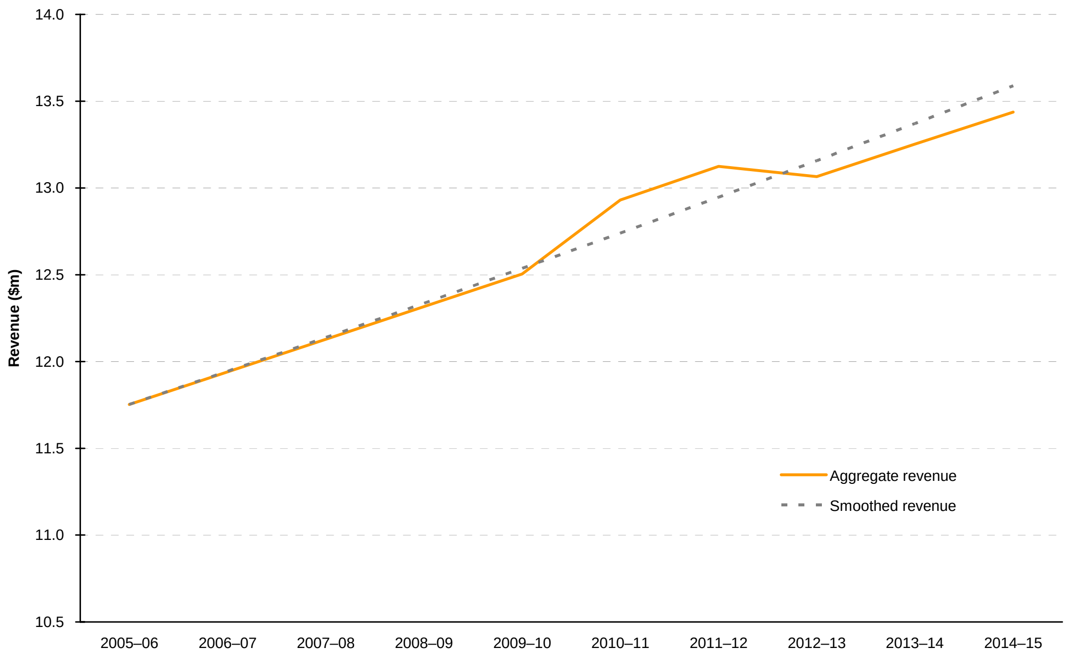
	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Smoothed AR	11.75	11.94	12.14	12.34	12.54	12.74	12.95	13.16	13.37	13.59

Because DJV's allowed revenue 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. The pro rata adjustment is contained in the AER's PTRM and determines the AR based on the number of days remaining in the 2005–06 financial year after Directlink ceases to be a market network service. For this decision, the AR for 2005–06 has been pro rated to $3.84 million, to coincide with the date of this decision (3 March 2006).

DJV's AR for subsequent years of the regulatory period is calculated based on the formula described in section 4.3.

Figure 4.1 provides the revenue path allowed in this decision (both smoothed and unsmoothed). The average revenue increase over the regulatory period is about 1.6 per cent per annum (nominal).

Figure 4.1 Revenue path 2005–06 to 2014–15 ($ million, nominal)



The smoothed revenue allowance of $11.75 million in 2005–06 to $13.59 million in 2014–15 that the AER has determined for DJV is, on average, around 25 per cent less than the requested smoothed revenue allowance of $16.50 million in 2005–06 to $18.10 million in 2014–15.

4.3.2 Timing

The AER's decision will only come into operation once Directlink's network service ceases to be classified as a market network service. If this does not occur by the date specified in paragraph 3 of the decision set out below, this decision will lapse and will cease to have any effect. The AER considers that DJV, having indicated its intention to convert Directlink's network service to a prescribed service, should be required to do so as soon as reasonably possible after the AER's decision is made.

This is subject to the qualification in paragraph 4 below. If there is an application for judicial review of this decision before Directlink's network service ceases to be classified as a market network service, this decision would almost certainly lapse before the matter was finally resolved. This means that, even if the AER's decision ultimately stands, it would have ceased to have effect and a fresh application would be required. To overcome this, the AER considers that if an application for judicial review of this decision is made before Directlink's network service ceases to be classified as a market network service, this decision will not lapse until 28 days after that application is withdrawn, dismissed or otherwise discontinued. This means that, for example, if an application for review is dismissed, DJV will have 28 days to proceed with conversion. That part of the revenue cap, as determined by the AER, that has not expired would apply for the remainder of the regulatory control period.

Summary of the AER's decision

Under clause 2.5.2(c) of the code, the AER determines that, on and from the time Directlink's network service ceases to be classified as a market network service:

1. Directlink's network service will be a prescribed service with an opening regulated asset base of $116.68 million at 1 July 2005.

2. The Directlink Joint Venturers will have a revenue cap for a regulatory control period ending on 30 June 2015. Its maximum allowed revenue (MAR) under this revenue cap will be as follows:

   MAR_1 = the AR for 2005–06 (year 1) of $11.75 million, to be adjusted on a pro rata basis according to the actual date of conversion

   X = the smoothing factor of 1.31 per cent, which represents the rate by which the AR falls in real terms.

   The formula used to calculate the MAR for each subsequent year is:

   $$MAR_t = AR_t + \left(\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct} \right) + P_t$$

   where:

   $$AR_t = AR_{t-1} \times (1 + \Delta CPI) \times (1 - X).$$

3. Subject to paragraph 4 below, this decision will lapse if Directlink's network service has not ceased to be classified as a market network service on or before Monday, 10 April 2006.

4. In the event that an application is made for judicial review of this decision before Directlink's network service has ceased to be classified as a market network service, this decision will lapse 28 days after the day on which any such application is withdrawn, dismissed, or otherwise discontinued.

Appendix A Review process

The following review process has occurred in consideration of DJV's 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.[50]
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.

[50] <http://www.aer.gov.au>

26 April 2005	The ACCC received IES's report on the review of interregional market benefits, which was placed on the AER's website. 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.
17 October 2005	The AER received IES's report on additional modelling of interregional benefits, which was placed on the AER's website.
8 November 2005	The AER made its draft decision and it is available on the AER's website.
9–31 December 2005	The AER received seven submissions on the draft decision, which are available on the AER's website.
21–23 February 2006	DJV provided submissions addressing Directlink's reliability and analysis of debt margin estimates.
21 February 2006	The AER received IES's report on the value of unserved energy, which was placed on the AER's website.
22 February 2006	The AER received NERA's report on the measure of central tendency, which was placed on the AER's website.
3 March 2006	The AER made its decision and it is available on the AER's website.

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
- South Australian Minister for Energy
- Country Energy
- Joint Transmission Network Owners.

Appendix B Service standards

This appendix sets out the AER's conclusion on DJV's service standards performance incentive scheme for the 2005–06 to 2014–15 regulatory period. As noted in the draft decision, for setting DJV's revenue cap, the AER will apply the performance incentive scheme outlined in the service standards guidelines, subject to the considerations set out in its decision.

Performance measures and definitions

The applicable performance measure to DJV's service standards incentive scheme is circuit availability. This comprises of three sub–measures including: scheduled, forced peak and forced off–peak energy availability. These measures are defined in table B.1.

Table B.1 Definition of circuit availability

Sub measures	Scheduled availability Forced peak availability Forced off–peak availability
Unit of measure	Percentage of total possible hours (capacity weighted) available.
Definitions	Forced outage event means the urgent and unplanned reduction in the real power transfer capability of Directlink that occurs as a necessary consequence of the actual or imminent occurrence of an event that poses, or has the potential to pose, an immediate threat to the safety of persons, hazard to any equipment or property or a threat to power system security. Scheduled outage event means the actual planned reduction in the real power transfer capability of Directlink that does not occur as a result of a forced outage event. Peak time is from 7.00 am to 10.00 pm weekdays (excluding public holidays in NSW). Off–peak is all other times.
Source of data	Directlink outage register and disturbance and outage report.
Formula	$100\% - \left(\frac{\text{Hours of total capacity unavailable per year}}{\text{Total possible no. of defined circuit hours per year}}\right) \times 100$
Exclusions	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).
Inclusions	'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. For avoidance of doubt, 'circuits' include all regulated transmission assets on DJV's network.
Definition of force majeure	(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.

Performance targets

Table B.2 sets out the performance targets according to the three sub–measures.

The weighting of the three availability measures collectively represent 1 per cent of DJV's allowed revenue (AR) which is placed at risk under the service standards incentive scheme.

Table B.2 Performance targets

Measure	Performance for maximum penalty (%)	Target performance (%)	Performance for maximum reward (%)	Weight (%)
Scheduled circuit availability	98.90	99.45	100	30
Forced outage circuit availability in peak periods	98.47	99.23	100	35
Forced outage circuit availability in off–peak periods	98.47	99.23	100	35

Capacity weighting

DJV's circuit availability is the capacity weighted average of all three units or 180 MW which make up the Directlink circuit. This is illustrated in the stylised example as shown in table B.3.

Table B.3 Example of circuit availability

Units	Capacity (MW)	Actual availability (hours)	Total possible availability (hours)	Total availability (%)
1	60	8000	8760	91.32
2	60	8200	8760	93.61
3	60	7500	8760	85.62
Circuit total (capacity weighted)	180	7900[1]	8760	90.18

[1] Actual availability circuit total (capacity weighted) is found as follows:
[60 MW × (8000 + 8200 + 7500) / 180 MW] = 7900 hours

Calculation of the service standards factor

The following formulae tables show the method for calculating DJV's service standards factor (s-factor) based on its performance in relation to circuit availability and the relevant sub–measures. Tables B.4–B.6 show the set of linear equations relevant to each sub–measure. The linear equations are represented graphically in figures B.1–B.3.

DJV's total s-factor result for each calendar year is determined as follows:

$$S_{ct} = S_1 + S_2 + S_3$$

where:

S_{ct} = total service standards factor (s-factor)

ct = time period/calendar year

S_1 = s-factor for scheduled circuit availability

S_2 = s-factor for forced peak circuit availability

S_3 = s-factor for forced off–peak circuit availability

The s-factor result for each sub–measure is determined as follows:

Table B.4 Scheduled circuit availability

							Where:				
S1	=	–0.003							Availability	<	98.90%
S1	=	0.545455	x	Availability	–	0.542455	98.90%	≤	Availability	≤	99.45%
S1	=	0.545455	x	Availability	–	0.542455	99.45%	≤	Availability	≤	100.00%
S1	=	0.003					100.00%	<	Availability		

Figure B.1 Scheduled circuit availability

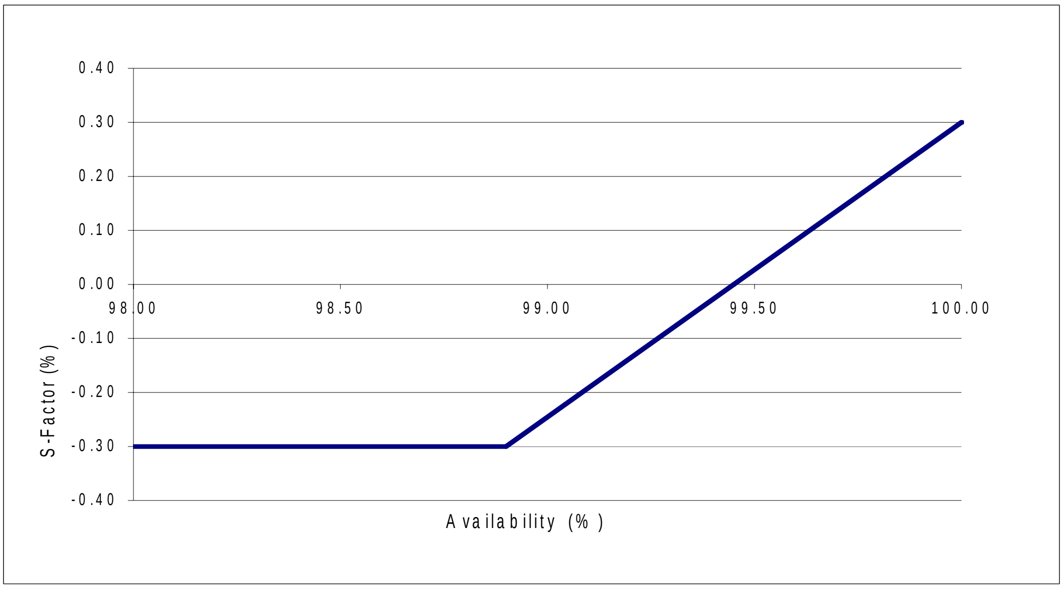


Table B.5 Forced peak circuit availability

							Where:				
S2	=	–0.0035							Availability	<	98.47%
S2	=	0.460526	x	Availability	–	0.456980	98.47%	≤	Availability	≤	99.23%
S2	=	0.454545	x	Availability	–	0.451045	99.23%	≤	Availability	≤	100.00%
S2	=	0.0035					100.00%	<	Availability		

Figure B.2 Forced peak circuit availability

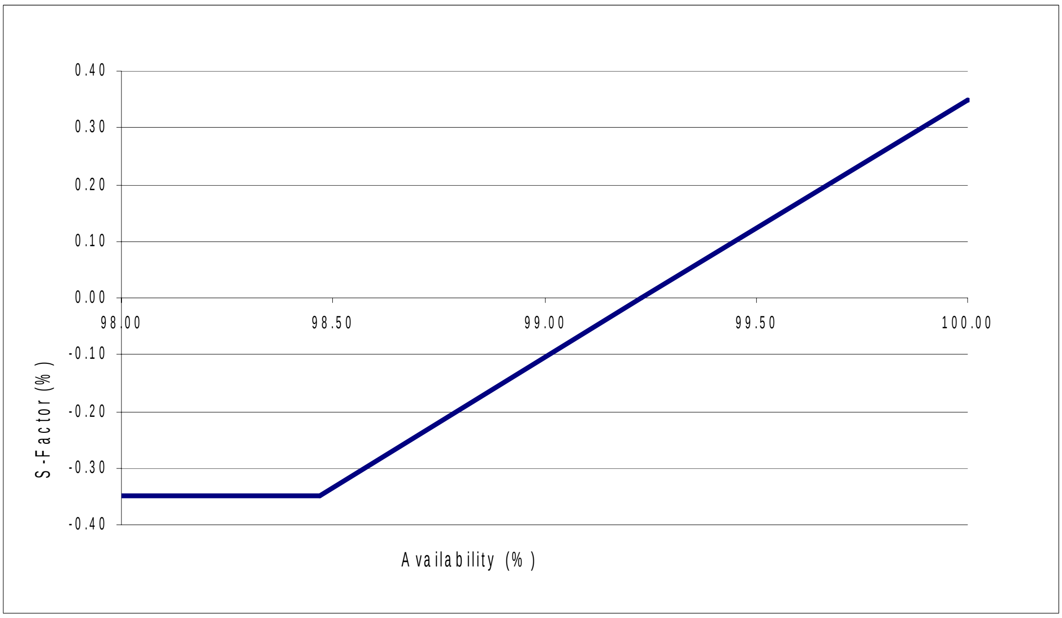
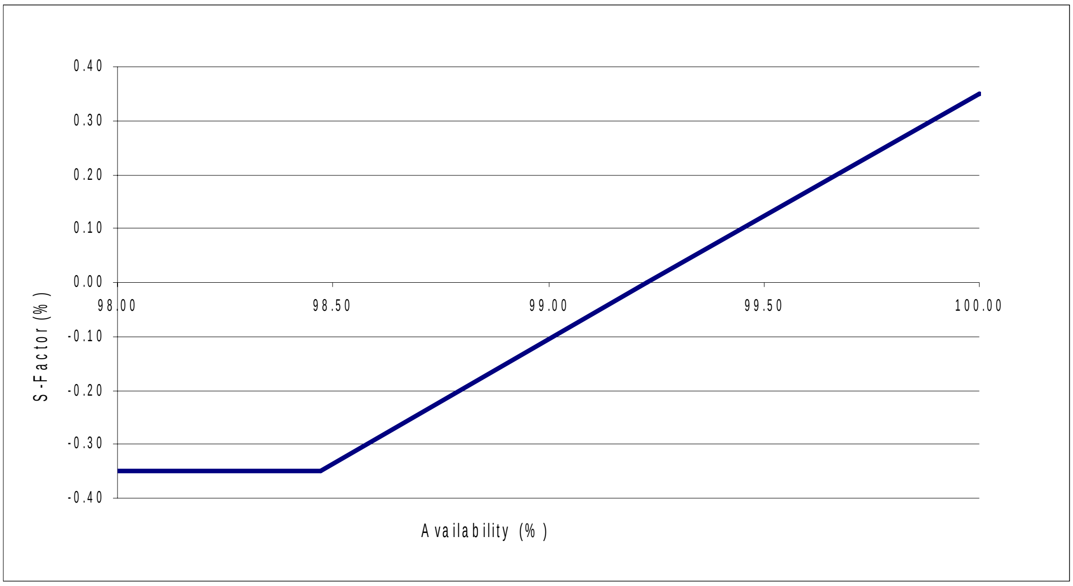


Table B.6 Forced off–peak circuit availability

							Where:				
S3	=	–0.0035							Availability	<	98.47%
S3	=	0.460526	x	Availability	–	0.456980	98.47%	≤	Availability	≤	99.23%
S3	=	0.454545	x	Availability	–	0.451045	99.23%	≤	Availability	≤	100.00%
S3	=	0.0035					100.00%	<	Availability		

Figure B.3 Forced off–peak circuit availability



Calculation of the financial incentive

DJV's financial incentive is determined by multiplying DJV's annual AR by the total s-factor result. The financial incentive may be a positive (or negative) financial bonus (or penalty) depending on the TNSP's performance over the relevant calendar year. The financial incentive is included in the maximum allowed revenue (MAR) for the financial year immediately following the relevant calendar year. The financial incentive and MAR formulae are set out in section 4.3 of this decision.

Annual reporting

In accordance with clause 6.2.5 of the National Electricity Rules (rules) and the service standards guidelines, DJV should record and report all performance measures annually on a calendar year basis. All reporting should be in accordance with the requirements outlined in the service standards guidelines.

The timetable for the annual compliance reporting is to be decided on an annual basis by agreement between the AER and DJV with due regard for the service standards guidelines and pricing imperatives.

Review of the scheme

The AER will review DJV's performance incentive scheme after five years from the date of this decision.

While the AER proposes to 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 rules. Unless the 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.

Appendix C Pass-through mechanism

Directlink Joint Venturers

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 Venturers for the regulatory control period ending on 30 June 2015.

Directlink Joint Venturers 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 3 March 2006 ('Date of Determination') set a *revenue cap* ('Revenue Cap') to apply to the Directlink Joint Venturers ('TNSP') for the *regulatory control period* ('Regulatory Control Period') ending on 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.

(i) 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 *Co-ordinating 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 word appearing in italics has the meaning assigned to it from time to time by the National Electricity Rules.

Note: For example, if, after the Date of Determination, the National Electricity Rules are amended so that:

(a) a word in italics is no longer defined in the National Electricity Rules; or
(b) the definition in the National Electricity Rules is no longer appropriate,

then the context may require that the word in italics has:

(c) the meaning last assigned to it by the National Electricity Rules; or
(d) the meaning assigned to a new equivalent term used in 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 the first day of the period covered by the Revenue Cap determined in accordance with section 4.3.2 of the *AER's* final decision setting the Revenue Cap.

Note: In summary, section 4.3.2 of the final decision provides that, unless the decision lapses, the Regulatory Control Period commences on the date that the TNSP's network service ceases to be classified as a market network service.

Date of Determination means 3 March 2006, 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(i):

(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, $126,000.

Note: The monetary amount specified in paragraph (a) is approximately one per cent of the TNSP's average *maximum allowed revenue* for a *financial year*, estimated at the Date of Determination.

(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 $126,000 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 Venturers (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.