DIRECTLINK JOINT VENTURE

Emmlink Pty Limited
ACN 085 123 486
HQI Australia Limited Partnership
ACN 086 210 488

PO Box 5118
Port Macquarie NSW 2444
p. (02) 6589-8777 f. (02) 6589-8658

Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue to 30 June 2015

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Background

Directlink is a transmission line that runs between Mullumbimby in New South Wales and Bungalora and Terranora in Queensland, and forms one of the links between the New South Wales and Queensland electricity regions of the National Electricity Market (‘**NEM’**). It has a nominal transfer capacity of 180 MW and came into operation on 25 July 2000. Directlink operates in parallel with and provides support to the higher voltage transmission network.

Emmlink Pty Ltd (‘**Emmlink**’) and HQI Australia Ltd Partnership (‘**HQIALP**’) are the owners of Directlink and are described collectively as the ‘**Directlink Joint Venturers**’.

Directlink’s network service is currently classified as a market network service and Directlink earns revenue from the National Electricity Market Management Company (‘**NEMMCO**’) by providing its market network service between the New South Wales and Queensland regions. However, The Directlink Joint Venturers now wish to convert Directlink to regulated status in accordance with clause 2.5.2(c) of the National Electricity Code (‘**Code**’), which states:

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

Nature of the Application

Accordingly, the Directlink Joint Venturers request that, upon network service provided by Directlink ceasing to be classified as a market network service, the Australian Competition and Consumer Commission (‘**Commission**’) determine that:

1. the network service provided by Directlink is a prescribed service for the purposes of the National Electricity Code; and

2. for the provision of this prescribed service, the Directlink Joint Venturers be eligible (subject to the performance incentive scheme proposed in section 6.6 of this Application) to receive the maximum allowable revenue from transmission customers (through coordinating network service providers) for a regulatory control period from the date of effect of the Commission’s final decision on this Application to 30 June 2015, as proposed in this Application.

This revised application supersedes that submitted to the Commission on 6 May 2004.

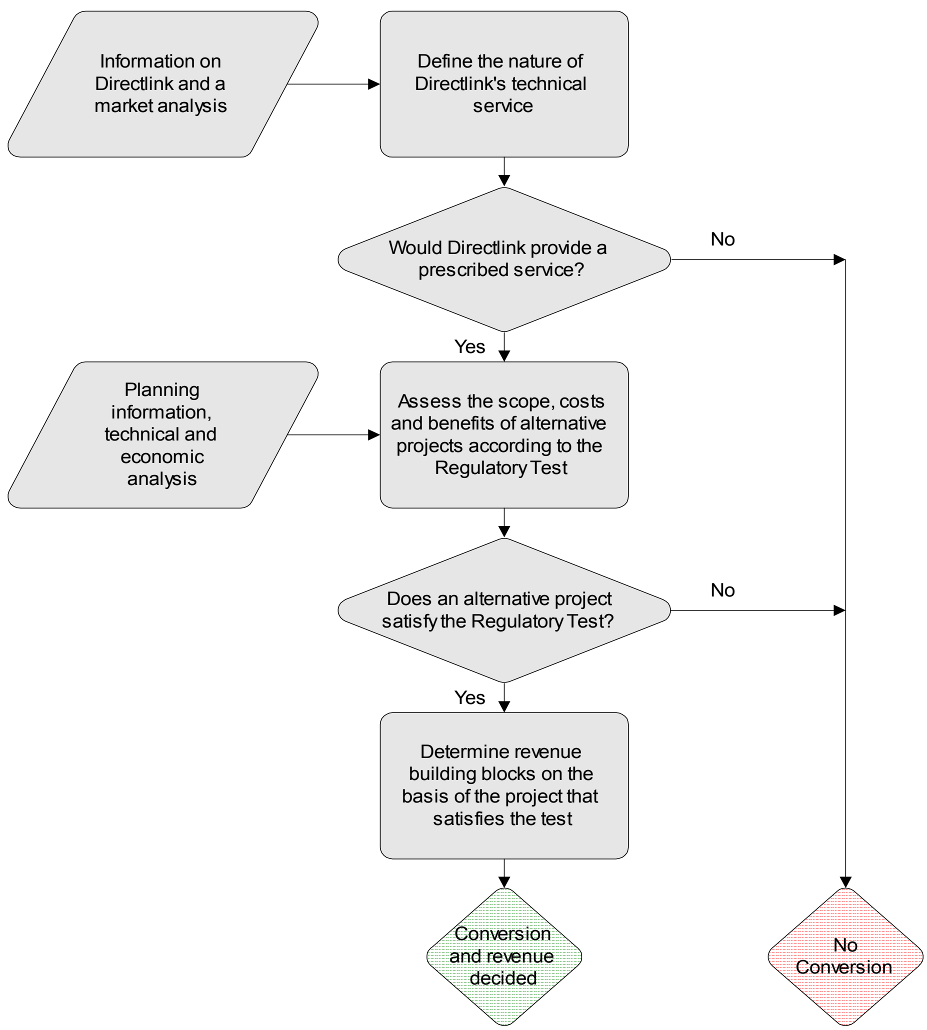
Analytical framework

The Code sets down no explicit process or criteria that the Commission must apply when exercising its discretion under clause 2.5.2(c). However, the Code does set some boundaries.

The Directlink Joint Venturers have applied an analytical framework and asset valuation methodology in this Application that reflects the Commission's Murraylink decision approach in relation to the determination of Directlink's asset value.[1] This analytical framework is illustrated in Figure E.1.

Figure E.1

ANALYTICAL FRAMEWORK FOR DETERMINATION OF DIRECTLINK APPLICATION



Source: Adapted from Murraylink decision, p. xiii.

[1] Murraylink decision, pp. xiv, 52.

The Directlink Joint Venturers have concerns about the Commission's approach in the Murraylink decision because this approach could produce anomalous and arbitrary results for Directlink that would be inconsistent with Chapter 6 of the Code. Should the Commission draw different conclusions in relation to the scope, costs and benefits of the alternatives projects, the Directlink Joint Venturers reserve their right to question more fundamentally the Commission's approach.

In a separate submission, that the Directlink Joint Venturers will put forward an analytical framework and asset valuation methodology that applies the Regulatory Test in a manner that does not produce anomalous and arbitrary results should the Commission draw different conclusions in relation to the scope, costs and benefits of Directlink's alternatives projects.

Definition of Directlink's network service

Directlink's network service can be described in terms of five inter-related elements of technical capability. Directlink:

- transfers active power between Mullumbimby and Terranora in both directions—Directlink provides a controlled, two-way injection capability into the northern New South Wales coastal and Queensland Gold Coast areas, subject to Directlink's rating and external network constraints defined by NEMMCO and Transmission Network Service Provider ('**TNSP**') constraint equations and the connection agreements.

- transfers reactive power in both directions and provide voltage control—Directlink has the ability to control reactive power flows independently of, and concurrently with, active power flow control, within overall thermal and voltage limits.

- provides network support to the Gold Coast and far north coast of New South Wales—Directlink is a direct current ('**DC**') link connecting the load centres of far north eastern New South Wales with that of the Queensland Gold Coast at the 132 kV/110 kV level. Directlink could provide its own unique network support services to the local networks. These services would flow on to potential network augmentation deferments in both states for planned augmentations to the Gold Coast or far north eastern New South Wales.

- facilitates greater inter-regional flows between the New South Wales and Queensland regions—Directlink also enables 187.5 MW of power to flow between the New South Wales and Queensland regions, subject to network constraint conditions. The increased inter-regional power flows facilitated by Directlink brings efficiency and reliability benefits to the NEM as a whole.

- could enhance the stability and security of the interconnected power system, particularly in New South Wales and Queensland—with appropriate upgrades, Directlink could have a beneficial impact on interconnected system stability and security in terms of transient, voltage and oscillatory stability.

Conversion

The Directlink Joint Venturers anticipate that the Commission will apply to this Application the same criterion for the conversion of Directlink that it applied in the Murraylink decision. This criterion is whether Directlink's network service would be a prescribed service—as defined by the Code—when it ceases to be classified as a market network service.[2] That is, does Directlink exhibit characteristics that are consistent with the definition of a prescribed service?

With consideration for the Commission's working definition of a prescribed service, the Directlink Joint Venturers have concluded that, after Directlink's network service ceases to be classified as a market network services, Directlink's network service:

- would not be a market network service;
- would not be excluded from a revenue cap under a more light-handed regime that might be imposed by the Commission; and
- would be a contestable service.

And, therefore, Directlink's network service would be a prescribed service.

Regulatory Test

In terms of applying the Regulatory Test to Directlink:

- comparable network and non-network alternatives that alleviate the emerging network constraints listed in section 2.3 have been identified—these alternatives include interconnectors, generation options, demand side options, and options involving other transmission and distribution network augmentations;
- the costs and benefits of each feasible comparable alternative for a range of credible market development scenarios and sensitivity scenarios have been estimated in accordance with the principles contained in the Regulatory Test;
- these alternatives are ranked for each scenario; and
- The project that maximises the market benefits to all those who produce, consume and transport electricity in the NEM in most but not all the credible market scenarios is the project that satisfies the Regulatory Test.

Burns and Roe Worley ('**BRW**') initially identified seven alternative projects reasonably comparable to Directlink:

Alternative 0—The Directlink project.

[2] Murraylink decision, pp. 14-5.

Alternative 1—A modern 'HVDC Light' link between Mullumbimby and Terranora with 180 MW capacity, active and reactive power support, and emergency response.

Alternative 2—A conventional high voltage DC link with 180 MW capacity, synchronous condensers, active and reactive power support, and emergency response.

Alternative 3—A high voltage AC link with 180 MW capacity with a phase shifting transformer, and capacitors at each end, protection and control systems with emergency response.

Alternative 4—A high voltage AC link with 180 MW capacity along with an auto-transformer and capacitors at each end, protection and control systems to Code standards.

Alternative 5—High voltage network augmentations in New South Wales and Gold Coast designed to address emerging network limitations in those areas due to load growth.

Alternative 6—Approximately 180 MW of embedded generation in the Gold Coast and far north east of New South Wales, and a demand management program.

However, BRW considers that Alternatives 4 and 6 are not reasonable alternatives to Directlink for the purposes of the Regulatory Test.

BRW estimated the costs and network deferral benefits of each of the other alternative projects, and TransÉnergie US Limited ('**TEUS**') estimated their inter-regional benefits.

To inform its costing estimates, BRW commissioned URS Australia ('**URS**') to:

- examine in detail the available transmission line route options for the alternative project to Directlink;
- prepare a desk-top assessment of the environmental and social constraints affecting the transmission corridor; and
- Identify the best and one additional route that are considered to have the minimum environmental mitigation measures necessary for there to be a reasonable probability of planning approval.

The URS Report was subsequently reviewed by Environmental Resources Management ('**ERM**'), who confirmed its substance. Further, copies of the report were also forwarded to the Department of Infrastructure, Planning and Natural Resources, Byron Council and Tweed Council for reference and to provide a basis for comments on the factors considered and the conclusions reached. At the time of finalising of the BRW report, only Tweed Council had been able to respond. The Council confirmed that the report identified and addressed the environmental and planning issues relevant to the project and study area.[3] The Council also indicated that the report

[3] This letter from Tweed Council is contained in Appendix F of this Application.

provided a good assessment of the issues and regulatory requirements considered significant to the project.

Based upon the Directlink Joint Venturers' analysis of these costs and benefits, Alternative 2 is more attractive than the alternative projects for the credible market development scenarios, as shown in Table E.1. That is Alternative 2 provides maximum net market benefits in scenarios 4, 5 and 12B by a substantial margin.

Of the 20 sensitivity test scenarios studied, Alternative 2 maximises the net market benefits in 9 cases and has the second highest net market benefits in 7 cases.

Table E.1

PROJECT RANKINGS FOR CREDIBLE MARKET DEVELOPMENT SCENARIOS

No.	Gen. bid	DR	Econ. growth	Proj. cost	1st ranking		2nd ranking		3rd ranking		4th ranking		5th ranking	
					Proj	RNB	Proj	RNB	Proj	RNB	Proj	RNB	Proj	RNB
4	LRMC	9%	High	100%	Alt 2	120.3	Alt 0	108.6	Alt 3	92.1	Alt 1	20.0	Alt 5	0.0
5	LRMC	9%	Med	100%	Alt 2	55.5	Alt 0	43.8	Alt 3	24.5	Alt 5	0.0	Alt 1	-44.8
6	LRMC	9%	Low	100%	Alt 5	0.0	Alt 3	-3.4	Alt 2	-24.3	Alt 0	-36.0	Alt 1	-124.6
11	SRMC	9%	Med	100%	Alt 5	0.0	Alt 2	-22.4	Alt 0	-34.1	Alt 3	-49.6	Alt 1	-122.7
12A	LRMC	9%	Med	110%	Alt 0	51.2	Alt 2	47.5	Alt 3	18.8	Alt 5	0.0	Alt 1	-62.8
12B	LRMC	9%	Med	90%	Alt 2	63.5	Alt 0	36.4	Alt 3	30.2	Alt 5	0.0	Alt 1	-26.8

Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group. Note: 'RNB' means net market benefits relative to Alternative 5, expressed in $M.

These results demonstrate that Alternative 2 maximises the market benefits to all those who produce, consume and transport electricity in the NEM in most but not all the credible market scenarios examined.

Therefore, Alternative 2 would pass the Regulatory Test.

Revenue path

Consequently, Alternative 2 determines the opening asset value, depreciation, and operating expenditure allowance for Directlink.

Directlink's revenue path has been calculated using the Commission's revenue model and is summarised in Table E.2.

Table E.2

DIRECTLINK'S ESTIMATED REVENUE PATH (HISTORICAL COST, NOMINAL, $M)

Year commencing 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Opening asset value	135.6	135.4	135.1	134.7	134.2	133.6	132.8	132.0	131.0	129.9
Return on capital	12.4	12.4	12.4	12.3	12.3	12.2	12.2	12.1	12.0	11.9
Return of capital	0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.2
Operating expenditure	3.3	3.4	3.5	3.6	3.6	4.0	4.0	3.9	4.0	4.1
Tax payable	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5
Imputation credits	-0.6	-0.6	-0.6	-0.6	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7
Unadjusted revenue allowance	**16.5**	**16.7**	**16.9**	**17.0**	**17.2**	**17.6**	**17.7**	**17.6**	**17.8**	**17.9**
Smoothed maximum allowable revenue	**16.5**	**16.7**	**16.9**	**17.0**	**17.2**	**17.4**	**17.6**	**17.7**	**17.9**	**18.1**

Values are in nominal dollars.

This represents a nominal annual revenue of $16.5M to $18.1M over 10 years with a present value of around $114M, assuming a nominal 'vanilla' weighted average cost of capital ('**WACC**') of 9.16% on 1 July 2005.

Performance incentive scheme

The Directlink Joint Venturers propose that part of their allowed revenues be placed at risk as an incentive to meet a benchmarked level of performance in terms of forced availability in peak and off-peak periods. The Directlink Joint Venturers will submit to the Commission the detail of its proposed performance incentive scheme in a separate submission.

Pass through rules

The Directlink Joint Venturers have endeavoured to identify all the efficient costs associated with the provision of Directlink's prescribed service, including the procurement of appropriate insurance. However, events could occur that are outside of the owners' control and that could substantially increase their costs and/or decrease the value of its regulatory asset base. Accordingly, Appendix H contains the pass-through rules that would be appropriate for Directlink.

Chapter 1

Introduction

1.1 Purpose of the Application

By this Application, the Directlink Joint Venturers request that, upon network service provided by Directlink ceasing to be classified as a market network service, the Commission determine that:

1. the network service provided by Directlink is a prescribed service for the purposes of the Code; and

2. for the provision of this prescribed service, the Directlink Joint Venturers be eligible (subject to the performance incentive scheme proposed in section 6.6 of this Application) to receive the maximum allowable revenue from transmission customers (through coordinating network service providers) for a regulatory control period from the date of effect of the Commission's final decision on this Application to 30 June 2015, as proposed in this Application.

This revised Application supersedes that submitted to the Commission on 6 May 2004. It sets out a description of Directlink and its network service, and the relevant information necessary for the Commission to make its determination.

1.2 The Directlink Joint Venture

Within this Application, the owners of Directlink, that is Emmlink Pty Ltd and HQI Australia Ltd Partnership, are described collectively as the '**Directlink Joint Venturers**'.

Emmlink and HQIALP have been established for the purpose of owning and operating Directlink and for providing Directlink's network service to the NEM. Emmlink and HQIALP own Directlink in equal shares.

Emmlink is a subsidiary of Country Energy, an electricity and gas distribution and retail business and statutory State-owned corporation constituted under the New South Wales *Energy Services Corporations Act 1995*.

HQIALP is a limited partnership established under the laws of Quebec and registered in both Australia and Canada between HQI Australia Pty Ltd (66.67%) and Le Fonds de Solidarité des Travailleurs du Québec ('**FSTQ**') Australia Pty Limited (33.33%). HQI Australia Pty Ltd is a subsidiary of Hydro-Québec International Inc. ('**HQI**'). HQI is wholly owned by Hydro-Québec.

Upon the conversion of Directlink's network service to a prescribed service, neither Emmlink nor HQIALP will carry on a *related business* within the meaning set down in the Commission's Ring-Fencing Guidelines[4], either singularly or together.

Country Energy will continue to provide operation and maintenance services for Directlink on behalf of both Directlink Joint Venturers.

1.3 Background

Directlink is an entrepreneurial network project designed by TransÉnergie US, developed by TransÉnergie Australia, and owned by the Directlink Joint Venturers.

Directlink currently earns revenue from the NEMMCO by providing a market network service between the New South Wales and Queensland regions.

Arrangements for the classification and operation of market network services in the NEM are based upon the Code changes brought about to apply the principles set down in the Safe Harbour Provisions developed by a NECA Working Group[5] in 1999.[6] The Commission granted these Code changes an interim authorisation in late 1999 and early 2000, and final authorisation in September 2001.[7]

In the NECA Working Group's view, the Safe Harbour Provisions represented a progression towards market-based provision of transmission services. The NECA Working Group nevertheless acknowledged that the concept of non-regulated interconnectors was 'somewhat experimental' and therefore recommended that an entrepreneurial interconnector be given the right to apply to convert to regulated status at any time. In the NECA Working Group's view, the option to convert would help ensure that investment was not inefficiently inhibited by non-commercial market design risks that only become apparent once the first interconnectors are operational.

The NECA Working Group made the following recommendation:

> *Option to convert to regulated status.* The interconnector owner can apply to convert to regulated status at any time. The revenue entitlement will be assessed at that time.

Subsequently, clause 2.5.2(c) of the Code provides the opportunity for a market network service to convert to a prescribed service.

> If an existing *network service* ceases to be classified as a *market network service* it may at the discretion of the *Regulator* or *Jurisdictional Regulator* (whichever is

[4] Australian Competition and Consumer Commission, *Decision: Statement of Principles for the Regulation of Transmission Revenues: Transmission Ring-Fencing Guidelines*, ('**Ring-Fencing Guidelines**'), 15 August 2002, p. 2.

[5] The National Electricity Code Administrator ('**NECA**') Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors.

[6] NECA Working Group, *Entrepreneurial Interconnectors: Safe Harbour Provisions* ('**Safe Harbour Provisions**'), November 1998.

[7] Australian Competition and Consumer Commission, *Applications for Authorisation: late Amendments to the National Electricity Code – Network pricing and Market Network Service Providers,* 21 September 2001.

> relevant) be determined to be a *prescribed service* or *prescribed distribution service* in which case the *revenue cap* or *price cap* of the relevant *Network Service Provider* may be adjusted in accordance with Chapter 6 to include to an appropriate extent the relevant *network elements* which provided those *network services*.

The NECA Working Group also stated that it was:

> …important that the conversion option should not shield the proponent from normal commercial risks, e.g. the risk of having over-judged the future demand for the interconnection service.

The NECA Working Group stated that the way to address this issue was to ensure that the regulated revenue entitlement is based on the assessed need for the facility at the time of the conversion application, rather than guaranteeing a return on the original capital cost.

The Commission has acknowledged this point in its final determination of NECA's authorisation application, which included clause 2.5.2(c) when it said that[8]:

> The Commission will consider the prudence of the network service at the time the conversion to a prescribed service occurs, rather than consider any earlier investment decisions. As such the investor would bear the risk of the Commission optimising down the value of the assets – with the consequence of reduced revenue streams, at the time it converted to regulated status and at each regulatory review into the future.

1.4 Basis and process of the Commission's determination

(a) Authority responsible

Given that Directlink is a transmission asset[9], for the purposes and timing of this Application, the Commission is the authority—the 'regulator'—responsible for:

- determining whether Directlink's network service is a prescribed service when it ceases to be classified as a market network service for the purposes of clause 2.5.2(c) of the Code; and
- determining transmission network service revenue cap for the provision of Directlink's network service for the purpose of clause 6.2.1 of the Code.

(b) Regulatory requirements for the determination of the Application

The Code sets down no explicit process or criteria that the Commission must apply when exercising its discretion under clause 2.5.2(c), and the Commission has some discretion as to how it applies the objectives and principles on Part B of Chapter 6 of

[8] Australian Competition and Consumer Commission, *Applications for Authorisation: late Amendments to the National Electricity Code – Network pricing and Market Network Service Providers,* 21 September 2001, p.137.

[9] This application confirms Directlink's status as a transmission network in section 2.2.

the Code. However, the Code does set some boundaries around the Commission's discretion.

The prescribed service determination

It is implicit in clause 2.5.2(c) that, before the regulator's determination that a network service is a prescribed service takes effect, the regulator would need to be satisfied of two things:

- that, after ceasing to be classified as a market network service, the network service would display the characteristics of a prescribed service as defined in the Code; and

- that the network service has ceased to be a market network service.

We note that, in its decision on the Murraylink Transmission Company application[10], the Commission satisfied itself on these two points. Given that the Commission has a Code obligation to ensure reasonable certainty and consistency of the outcomes of regulatory processes over time[11], the Directlink Joint Venturers have assumed that the Commission will seek to be satisfied on the same points.

Accordingly, the first point is incorporated into an analytical framework, which is described in section (c) below and applied in relation to the question of conversion in Chapter 3 of this Application.

With regard to the second point, the Commission can be satisfied by ensuring that its determination only takes effect upon Directlink's network service ceasing to be classified as a market network service. A chain of events that enables this to occur is set out in Table 1.1.

The revenue determination

Clause 6.2.2 in Chapter 6 of the Code sets down the outcomes that the transmission revenue regulatory regime to be administered by the Commission pursuant to this Code must seek to achieve. These include:

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

(b) an incentive-based regulatory regime which:

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

[10] Australian Competition and Consumer Commission, *Decision: Murraylink Transmission Company Application for Conversion and Maximum Allowable Revenue* ('**Murraylink decision**'), 1 October 2003.
[11] Clauses 6.2.2(j) of the National Electricity Code.

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

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

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

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

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

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

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

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

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

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

Further, clause 6.2.3(d)(4)(iv) requires the Commission to administer a transmission revenue regulation regime in accordance with principles that include:

… valuation of assets brought into service after 1 July 1999 (‘new assets’), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the *ACCC* and in determining the basis of asset valuation to be used, the *ACCC* must have regard to:

A the agreement of the Council of Australian Governments of 19 August 1994, that *deprival value* should be the preferred approach to valuing *network* assets;

B any subsequent decisions of the Council of Australian Governments; and

C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2.

Accordingly, in relation to all its revenue cap decisions except for the Murraylink decision, the Commission has valued transmission assets—many of which came into service after July 1999 and only a small proportion of which were demonstrated to have passed the Regulatory Test—with regard to an optimised deprival replacement cost ('**ODRC**') valuation, which was often undertaken by an independent expert on behalf of a jurisdictional body.[12]

For the Murraylink decision, the Commission took a different approach. It determined that it would apply the Regulatory Test to determine:

- whether one of Murraylink's alternative projects 'satisfies the Regulatory Test' and, only on that basis, whether the Commission would set a revenue cap for Murraylink's prescribed service;
- if it would set a revenue cap, what asset value, operating and maintenance allowance and depreciation schedule it would use to determine the revenue cap for Murraylink's prescribed service.

The Directlink Joint Venturers have applied an analytical framework and asset valuation methodology in this Application that reflects the Commission's Murraylink decision approach in relation to the determination of Directlink's asset value.[13]

However, the Directlink Joint Venturers have concerns about that Commission's analytical framework and asset valuation methodology in the Murraylink decision because this approach could produce anomalous and arbitrary results for Directlink that would be inconsistent with Chapter 6 of the Code. They concur with similar concerns expressed by the Murraylink Transmission Company[14] and National Economic Research Associates[15]. Should the Commission draw different conclusions in relation to the scope, costs and benefits of the alternatives projects, the Directlink Joint Venturers reserve their right to question more fundamentally the Commission's approach.

In a separate submission, the Directlink Joint Venturers will put forward an analytical framework and asset valuation methodology that applies the Regulatory Test in a manner that does not produce anomalous and arbitrary results should the Commission draw different conclusions in relation to the scope, costs and benefits of Directlink's alternatives projects.

[12] For example in Australian Competition and Consumer Commission, *Decision: Tasmanian Transmission Network Revenue Cap 2004-2008/9*, 10 December 2003.

[13] Murraylink decision, pp. xiv, 52.

[14] For example in the letter of 12 August 2003 from Mr Stéphane Mailhot of Murraylink Transmission Company to the Commission, Attachment 2.

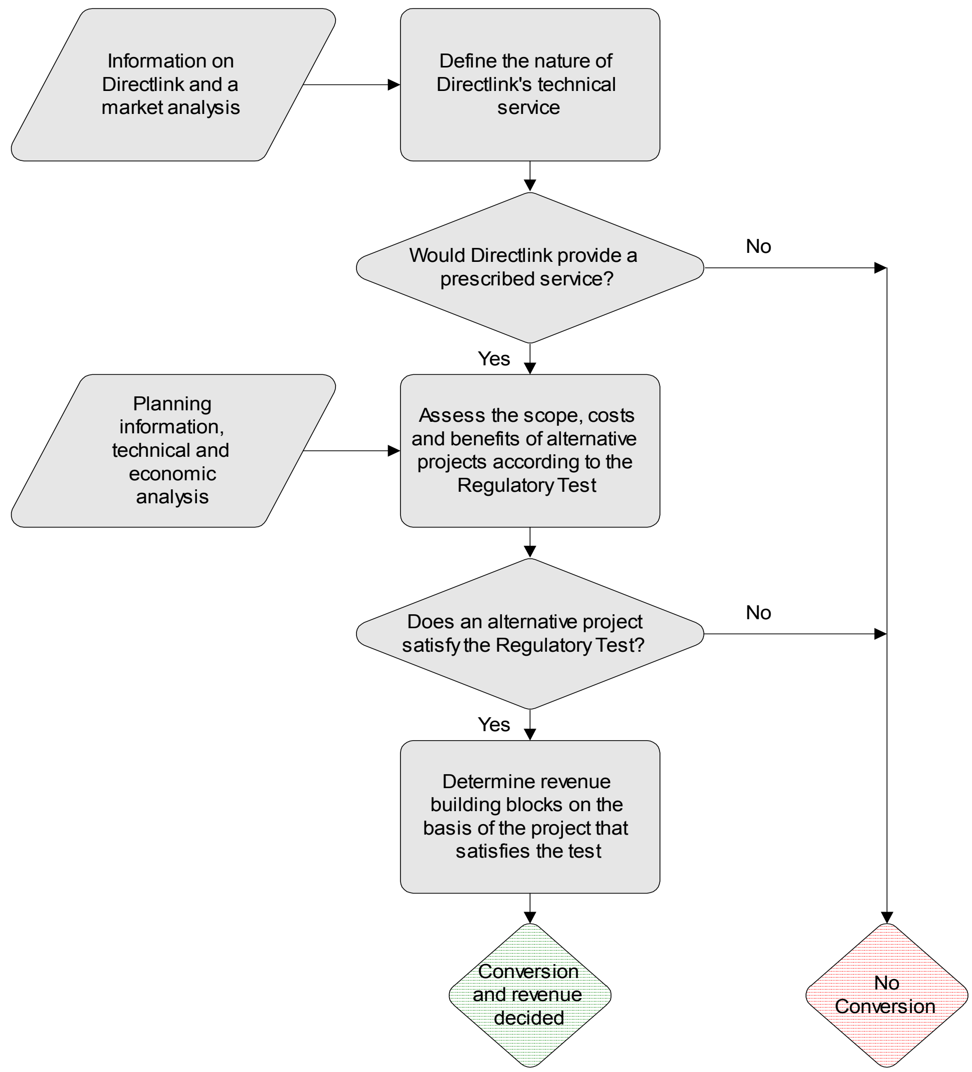
[15] NERA, *Comments on the ACCC's Preliminary View in Relation to Murraylink's Application for Regulated Status*, July 2003, submitted by TransGrid to the Commission on 18 July 2003.

(c) Analytical framework applied in this Application

The analytical framework applied to this Application is illustrated in Figure 1.1.

Figure 1.1

ANALYTICAL FRAMEWORK FOR DETERMINATION OF DIRECTLINK APPLICATION



Source: Adapted from Murraylink decision, p. xiii.

Each critical decision component of the framework is explained below.

Would Directlink provide a prescribed service?

To answer this question one must first describe Directlink's network service, which would be provided as a prescribed service upon conversion, in technical terms.

Directlink's network service can then be assessed in terms of the extent to which it may be defined as a prescribed service according to the Commission's interpretation of what the Code means be a prescribed service. If the Commission concludes that Directlink's network service can be defined as a prescribed service, the Commission would determine that Directlink's network service is a prescribed service.

This Application provides an independent expert definition of Directlink's network service and an argument as to why Directlink's network service may be defined as a prescribed service according the Commission's own definition of prescribed service.

Does an alternative project satisfy the Regulatory Test?

For the purpose of applying the Regulatory Test in the manner set down by the Commission, alternative projects with 'a level of similarity' to Directlink must be considered. Directlink itself will form the basis of one of the alternatives. The features of the alternative projects need to be justified on economic, technical and environmental grounds.

This Application provides independent and expert advice on the selection of Directlink's alternative projects and the estimation of their full life-cycle capital and operating costs—BRW's report, *Directlink, Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC* ('**BRW Report**'), contained in Appendix D[16].

This Application also provides an estimate of the market benefits of Directlink's alternative projects calculated in accordance with the guidelines in the Regulatory Test. This estimate draws upon information contained in:

- the BRW Report on the extent to which the alternative projects defer reliability augmentations and the relative economic benefits that result; and
- TransÉnergie US Limited's ('**TEUS's**') reports, *Estimation of Directlink Alternative Projects' Market Benefits* ('**TEUS Report**') and *Estimation of Directlink Alternative Projects' Market Benefits – Supplementary Report* ('**TEUS Supplementary Report**'), both contained in Appendix G, on the market benefits that each of the alternative projects could provide by enabling increased inter-regional power flows.

The scope, costs and benefits of the alternative projects indicate that an alternative project would satisfy the Regulatory Test. The Application proposes Directlink's revenue path on the basis of that alternative project.

[16] The BRW Report contained in this Application supersedes that included with the Directlink Joint Venturers' original application of 6 May 2004.

(d) Process for decision and when the decision may take effect

The Code is silent on the detail of the process to be adopted in respect of clause 2.5.2(c). However, the Directlink Joint Venturers have assumed that the Commission will apply the same process to its consideration to this Application as the Commission has applied to its consideration of other transmission revenue decisions.

The Directlink Joint Venturers understand that the Commission could potentially follow the process timetable that is set out in Table 1.1.

Table 1.1

PROCESS FOR LODGEMENT AND CONSIDERATION OF THE DIRECTLINK APPLICATION

Date	Action
6 May 2004	• The Directlink Joint Venturers lodged their original application. • The Commission notified stakeholders of receipt of application and timetable for consideration, and sought comment on the application.
May-June 2004	• The Commission's consultants reviewed the original application and expert reports.
July 2004	• The Directlink Joint Venturers notified the Commission that it will submit a supplementary document to its Application.
30 August 2004	• The Commission requested that the Directlink Joint Venturers submit a complete revised application package.
20 September 2004	• The Directlink Joint Venturers lodge this revised Application. • The Commission notifies stakeholders of receipt of revised application and timetable for consideration, and seeks comment.
October 2004 – February 2005	• The Commission publishes its consultants' reports and seeks comment from stakeholders. • The Directlink Joint Venturers provide further information to support their case and to address issues raised by consultants and stakeholders.
March 2005	• The Commission publishes its draft decision.
April– May 2005	• The Commission consults on its draft decision and conducts a public forum, if requested. • The Directlink Joint Venturers submit to the Commission a revised access undertaking.
June 2005	• ACCC publishes its final decision, which is worded to take effect upon the Directlink Joint Venturers notifying NEMMCO that Directlink is to cease to be classified as a market network service. • On the basis of the Commission decision, Directlink Joint Venturers notify NEMMCO that Directlink is to cease to be classified as a market network service.

The Directlink Joint Venturers understand that the Commission's final determination of this Application may take effect only when the Directlink Joint Venturers cease to classify Directlink's network service as a market network service. The Directlink Joint Venturers will liaise with NEMMCO during the Commission's consideration of the Application to ensure that, upon the Venturers ' notification to NEMMCO, Directlink can cease to be classified as a market network service soon after the Commission makes its decision.

(e) Variation to the analytical framework or process

This Application has been prepared on the basis of the Commission's views that are expressed in the Murraylink decision and specific guidance received from the Commission and its staff, relevant provisions of the Code, previous Commission decisions, and corresponding Commission guidelines.

The Directlink Joint Venturers request that the Commission promptly advise them if, at any stage during this process, the Commission:

- considers matters beyond that contained in the analytical framework presented in this Application may be taken into account in the exercise of its discretion to determine the application to convert;
- proposes to adopt a process that differs materially from the process outlined above; or
- proposes to adopt an approach to determining a revenue cap that differs from that proposed in the Application.

This will allow the Directlink Joint Venturers to vary or resubmit the Application, if necessary.

1.5 Content and structure of this Application

This Application contains all the information required by the Commission's Information Guidelines and other information that supports the Application.

Substantial portions of this Application have been prepared on the basis of work done or reviewed by independent and internationally recognised expert consultants, including BRW and TEUS.

Chapter 2 describes Directlink and the nature of its network service if it becomes regulated.

Chapter 3 reasons that Directlink's network service may be classified as a prescribed service and that the Commission may determine that Directlink should convert to regulated status.

Chapter 4 contains an application of the Commission's Regulatory Test to Directlink generally in accordance with the intent of current clause 5.6.6 of the Code.

Chapter 5 covers capital financing and taxation issues, including the determination of an appropriate cost of capital and a net tax allowance.

Chapter 6 describes the manner in which Directlink Joint Venturers' proposed revenue path is calculated and how this might be adjusted for performance incentive rewards and penalties. Rules are also presented to determine the manner in which costs large unmanageable risks might be passed through.

Consultants' reports and schedules required by the Commission are contained in the appendices of this Application.

Appendix I of this Application contains schedules and information prescribed by the Commission's Information Requirements Guidelines and is considered by Directlink Joint Venturers to be commercially sensitive and, accordingly, has been marked 'Sensitive Business Information – Confidential'. The Directlink Joint Venturers request that the Commission keep all of the information in Appendix I confidential.

Chapter 2

Directlink's Network Service

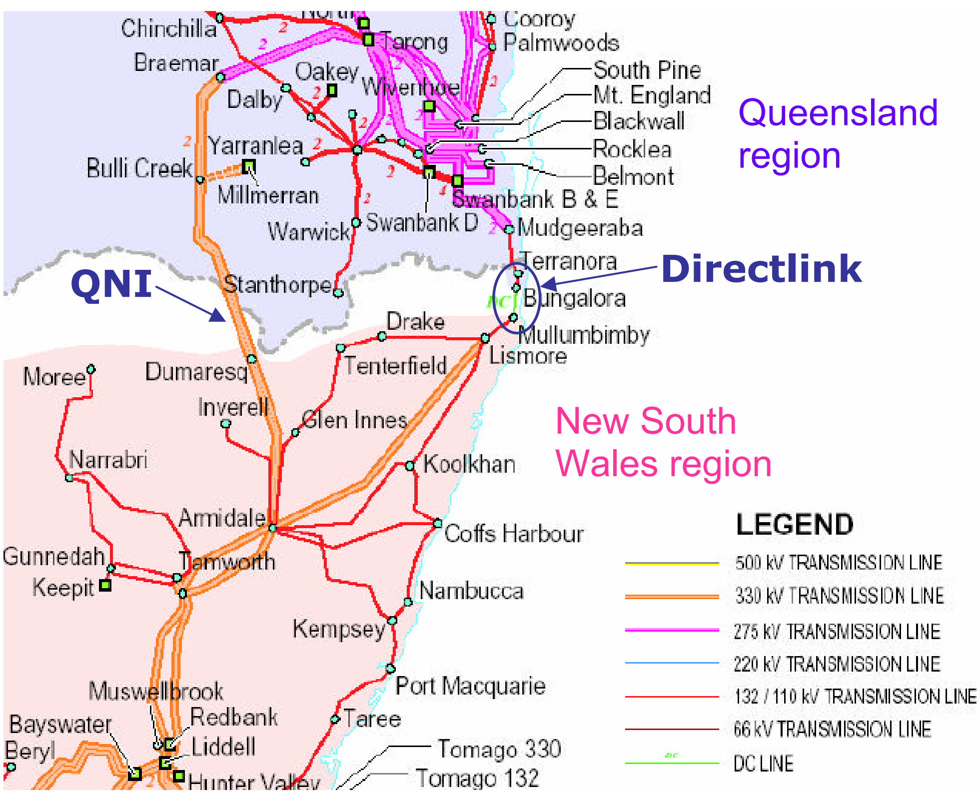
This chapter describes the nature and extent of Directlink's network service. It draws extensively from the BRW Report and the TEUS Report, which are contained in Appendices D and E of this Application, respectively.

2.1 Description of the Directlink asset

Directlink is a power line with a nominal transfer capacity of 180 MW. It runs between Mullumbimby and Bungalora (80 kV DC) and between Bungalora and Terranora (110 kV AC) as shown in Figure 2.1. It forms one of the links between the New South Wales and Queensland electricity regions of the NEM. Directlink uses ABB HVDC Light technology, and its cable is buried underground or laid in galvanised steel ducting for its entire 63 km length. Directlink came into operation on 25 July 2000.

Figure 2.1

LOCATION OF DIRECTLINK



Source: NEMMCO 2003 Statement of Opportunities, Appendix E (reproduced with permission)

Prior to Directlink being commissioned, the Interconnector Options Working Group undertook a technical assessment of Directlink and published its report in July 1999[17], as is currently required under clause 5.6.3(j) and 5.6.6(b)(4) of the Code. Since that time, the Queensland to New South Wales interconnector ('**QNI**') and other network augmentations that could affect flows across Directlink have been constructed and commissioned.

2.2 Directlink is a transmission network

The National Electricity Code defines a transmission network to be:

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

Directlink operates at 80 kV DC—which is between 66 kV and 220 kV.[18]

The circuit path created by the 132 kV circuits between Mullumbimby and Lismore, Directlink, and the 110 kV circuits between Terranora and Mudgeeraba operates in parallel with QNI and can provide support to the transmission network.

When Directlink is flowing north, it supports voltage in the Gold Coast and alleviates load on the 275 kV Swanbank to Mudgeeraba lines. When Directlink is flowing south, it supports voltage in the far north coast area of New South Wales and alleviates load on the 330 kV Armidale to Lismore line and the 132 kV system. Flows across Directlink can influence spot prices in the Queensland and New South Wales market.

For these reasons, Directlink is a transmission network.

2.3 Emerging network constraints

Powerlink and Energex have indicated that the existing electricity system supplying the Gold Coast/Tweed zone must be augmented before October 2005 if supply reliability is to be maintained during a single contingency.[19]

[17] Interconnector Options Working Group, *Directlink Transfer capability (Prior to QNI)*, Version 1.1, 15 July 1999.

[18] The Code makes no distinction between DC and AC voltages.

[19] Powerlink Queensland, *Emerging Transmission Network Limitations – Electricity Transfer to the Gold Coast and Tweed Area*, August 2003, p. 1 and Powerlink Queensland, *Final Report, Proposed New Large Network Asset – Gold Coast and Tweed Areas*, 6 July 2004, pp. 13-4.

Similarly, TransGrid has stated that the capacity of the existing system at the Far North Coast of New South Wales is approaching the limits imposed by two constraints. The first is unacceptably low voltages on outage of the 330 kV line from Armidale to Lismore at times of high load. The other is the rating of the Armidale to Koolkhan 132 kV line being exceed on outage of the 330 kV line from Armidale to Lismore at time of high load during summer.[20]

BRW has analysed the power system and documents that Powerlink and TransGrid have published and generally confirmed their findings.

2.4 Technical elements of Directlink's network service

Directlink's network service can be described in terms of five inter-related elements of technical capability:

(a) Transfer active power between Mullumbimby and Terranora in both directions

Directlink consists of three independent units each designed to provide a nominal power transfer capability of 60 MW, giving it a total nominal capability of 180 MW. However, Directlink's as-tested power transfer capability is actually 187.5 MW sending and 174.9 MW receiving. BRW has described Directlink's ability to transfer active power subject to network constraints in the broader network as follows.[21]

Directlink provides a controlled, two-way injection capability into the north eastern New South Wales coastal and Queensland Gold Coast subregions, subject to Directlink's rating and external network constraints defined by NEMMCO and the TNSP constraint equations and the connection agreements. The constraints on Directlink's full capability are presently voltage and thermal network constraints in both the New South Wales network around Lismore and the Queensland network around Mudgeeraba. In comparison, QNI constraints are predominantly stability related for imports to New South Wales and thermal related for imports to Queensland.

Directlink presently has a simple emergency tripping scheme ('**ETS**') implemented at remote substations to trip off Directlink in the advent of loss of the Armidale to Lismore line whilst power is flowing north to Queensland. It also has an emergency control system ('**ECS**') designed to prevent overloading of the Powerlink assets due to the operation of Directlink with power flowing south to New South Wales. The ECS monitors a number of parameters in the Powerlink network and will initiate an alarm to the Directlink operator when preset conditions are exceeded and then a trip of the link if these conditions are not relieved within a prescribed time. This means that Directlink is not able to actively support the network after the critical outage, particularly during periods of high demand in the north eastern New South Wales and Gold Coast subregions. Further extensions and upgrading to the ETS are being made as part of

[20] TransGrid, *Emerging Transmission Network Limitations on the New South Wales Far North Coast*, August 2003, p. 3.

[21] BRW Report, pp. 12-13.

implementation of the network services agreement between Powerlink and the Directlink Joint Venturers.

The present constraints on Directlink (also impacting QNI) identified by BRW include:

For flows from New South Wales to Queensland, the Directlink constraints arise from:

- voltage stability limit around lower north coast area of New South Wales;
- Armidale – Lismore 132 kV thermal limits;
- Tamworth – Armidale 330 kV thermal limit;
- Liddell – (Muswellbrook) – Tamworth 330 kV thermal limits;
- Lismore – Mullumbimby 132 kV thermal limit;
- Lismore – Lismore 132 kV thermal limit; and
- Directlink's active power flow capability.

For flows from Queensland to New South Wales, the Directlink constraints arise from:

- voltage stability limit in the Gold Coast area of Queensland (revised since the installation of Molendinar 275 kV);
- Mudgeeraba – Terranora 110 kV thermal limit;
- Swanbank – Mudgeeraba / Molendinar 275 kV thermal limit; and
- Directlink's active power capability.

Constraint equations determining the value of the constraints are held by NEMMCO and are formulated by NEMMCO and the TNSPs. However, BRW has independently assessed the network constraints in the Gold Coast and north eastern New South Wales regions by modelling and simulating the entire extra-high voltage networks between Tarong in Queensland and Liddell in New South Wales. This section of the network includes all of the Gold Coast and far north east New South Wales (and parts of the lower north New South Wales Coast—specifically the area around Coffs Harbour) including Directlink and QNI.

(b) Transfer reactive power in both directions and provide voltage control

Directlink has the ability to control reactive power flows independently of, and concurrently with, active power flow control, within overall thermal and voltage limits.

This facility can be used to control the voltage of the AC network independently at both the sending and receiving ends of the link during normal network operations or following a network contingency.

This voltage control is continuous, rather than occurring in discrete steps. For this reason it is a superior type of control to the switched capacitors or reactors which have been used over many decades. Its capacity to provide on-line, continuous regulation of network voltages is similar to the control provided by a synchronous condenser or static VAr compensator ('**SVC**'). Even with the DC link cables out of service, the voltage control can still be provided at each end of the link.

The capability of Directlink's reactive support is limited by the following:

- 110 kV Bus voltage at Terranora – voltage outside acceptable limits;
- 132 kV Bus voltage at Mullumbimby – voltage outside acceptable limits;
- Lismore – Mullumbimby 132 kV thermal limit;
- Mudgeeraba – Terranora 110 kV thermal limit; and
- Directlink's reactive power capability.

The Directlink Joint Venturers are contracted currently by NEMMCO to provide a network control ancillary service ('**NCAS**') to the NEM. Under this contract, Directlink supplies the capacity to provide reactive power to, or absorbs reactive power from, the transmission network in order to maintain the transmission network within its voltage and stability limits following a credible contingency event. The contracted capacity is 55 MVAr at 95% availability. The Directlink Joint Venturers envisages that Directlink NCAS service would become part of its prescribed service when Directlink becomes regulated.

(c) Provide network support to the Gold Coast and far north coast of New South Wales

Directlink operates in parallel with the double circuit 330 kV QNI interconnector providing an interconnection between the New South Wales and Queensland regions. This parallel operation means that there is some interdependency between the two interconnectors in the constraint equations. Despite this, QNI and Directlink connect into quite different parts of the transmission network. Directlink is a DC link connecting the load centres of far north eastern New South Wales with that of the Queensland Gold Coast at the 132 kV/110 kV level, whilst QNI is an AC link connecting the 330 kV New South Wales system with the 275 kV Queensland system.

For these reasons, Directlink could provide its own unique network support services to the local networks. These services would flow on to potential network augmentation deferments in both states for planned augmentations to the Gold Coast or far north east New South Wales.

(d) Facilitate greater inter-regional flows between the New South Wales and Queensland regions

Directlink also enables 187.5 MW of power to flow between the New South Wales and Queensland regions, subject to network constraint conditions. Where one region has significant surplus generation, or where there is load diversity between the regions, Directlink allows for the sharing of generation reserves. For a given generation inventory, Directlink's ability to share reserves would reduce the number and duration of occasions where regional demand exceeds available supply. In this way, the increased inter-regional power flows facilitated by Directlink brings efficiency and reliability benefits to the NEM as a whole.

(e) Enhance the stability and security of the interconnected power system, particularly in New South Wales and Queensland

Directlink could have a beneficial impact on interconnected system stability and security in terms of transient, voltage and oscillatory stability.

Directlink has an impact on the transient stability constraints by regulating the flow on QNI and by impacting indirectly on other regional flows by allowing different generation dispatch patterns.

Voltage stability/instability refers to the phenomenon of voltage collapse that can occur on parts of a power system after a credible contingent event, or because transmission lines are heavily loaded. Directlink provides significant voltage stability benefits to the system. The extent of these benefits is defined by the constraint equations published by NEMMCO.

Oscillatory stability is the capacity of an interconnected power system not to spontaneously commence under-damped internal low frequency oscillations between individual generators.

Directlink can improve oscillatory stability in three distinct ways:

- by regulating the power flow on QNI;
- by allowing a reduction in the generation dispatch levels of either Queensland or New South Wales, depending on which area is likely to experience oscillatory instability; and.
- by rapidly varying the flow of power between the two states it is possible to introduce power system damping which improves oscillatory stability. Directlink can achieve this by the overt control of its power transfer, but it also provides system damping during its normal operation, without the need of additional controls.

The regulation of power flow on QNI enables an additional transfer of up to the active power capability of Directlink between the New South Wales and Queensland regions, assuming there is no oscillatory stability issue associated with generation dispatch.

At this stage, the market benefits associated with the stability support capability of the alternative projects have not been included in the application of the Regulatory Test in Chapter 4.

Chapter 3

Conversion

3.1 Criterion for conversion

The Directlink Joint Venturers anticipate that the Commission will apply to this Application the same criterion for the conversion of Directlink that it applied in the Murraylink decision.

This criterion is whether Directlink's network service would be a prescribed service—as defined by the Code—when it ceases to be classified as a market network service.[22] That is, does Directlink exhibit characteristics that are consistent with the definition of a prescribed service?

The Commission has taken the view that this criterion is appropriate for four reasons[23]:

- the NECA Working Group intended to provide a right for a market network service provider to apply to convert to ensure that investment was not inefficiently inhibited;

- the Commission had stated previously that it would consider each conversion application on a case-by-case basis[24];

- the Commission's approach to asset valuation for a converting asset would ensure that the Regulatory Test is not bypassed and transmission customers do not bear the costs of inefficient investment; and

- the conversion option enables market network services providers to reduce the risks of their investment by having the option to apply for the determination of a regulated revenue, and, by reducing the risks, the opportunity for conversion encourages efficient transmission investment.

The Commission has also placed weight on Murraylink Transmission Company's argument that conversion of Murraylink could provide economic efficiency benefits from a more certain planning environment and better use of existing network capacity.

Sections 3.2 and 3.3 of this Application acknowledge the Commission's definition of prescribed service and assess Directlink's network service accordingly.

[22] Murraylink decision, pp. 14-5.
[23] ibid., pp. 15-6.
[24] Australian Competition and Consumer Commission, *Applications for Authorisation: late Amendments to the National Electricity Code – Network pricing and Market Network Service Providers,* 21 September 2001, p. 137.

3.2 Definition of prescribed service

After considering the strict Code definitions of prescribed service, transmission service and a transmission revenue cap, and the provisions of Part B of Chapter 6, the Commission has derived a 'working definition' of prescribed service.[25]

> Given the above, a 'working definition' of a prescribed service is a service that is not:
>
> (a) a Market Network Service;
>
> (b) excluded from the revenue cap under a more light handed regime imposed by the Commission pursuant to clause 6.2.3(c);
>
> (c) found to be contestable under clause 6.2.4(f).

3.3 Would Directlink provide a prescribed service?

Analysis as to whether Directlink's network service would satisfy the ACCC's working definition of a prescribed service is set out below. Given that Directlink's relevant circumstances are not materially different to those of Murraylink, this Application assesses Directlink's network services against the limbs of the Commission's definition of prescribed service in the same terms as the Commission used for the Murraylink decision.

Is Directlink's network service a Market Network Service?

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

Should the Commission impose a more light-handed regulatory regime?

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

Does Directlink provide a contestable service?

Jurisdictional guidelines for testing the degree of competition in the supply of excluded (non-prescribed) services have been examined to decide how (and if) to regulate these services and, using these guidelines, to assess, whether the market for Directlink's network service would be characterised by effective or potential competition.

[25] Murraylink decision, p. 17.

The Commission may consider an analysis of the market for Directlink's network service in terms of the framework set out in Table 3.1 both in terms of the market being:

- the market for the transport of power between the Queensland and New South Wales regions; and
- the market for support to the Gold Coast and far northern New South Wales networks.

Table 3.1

CRITERIA FOR ASSESSING THE MARKET FOR DIRECTLINK'S NETWORK SERVICE

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

All other transmission interconnectors in the NEM provide prescribed services, and the only reason Directlink does not is because its network service is classified as a market network service.

Given this analysis, the Commission should conclude that the conditions for effective or potential competition are weak or not present under both market definitions, and Directlink's network service is not a contestable service.

Therefore, Directlink's network service would satisfy all three limbs of the Commission's test for a prescribed service and satisfy the first criterion for conversion to a prescribed service.

Chapter 4

Application of the Regulatory Test

This chapter draws extensively from the BRW Report, the TEUS Report and the TEUS Supplementary Report, which are contained in Appendix D and Appendix G of this Application, respectively.

4.1 The Regulatory Test process

This Chapter 4 contains an application of the Regulatory Test to Directlink generally in accordance with the intent of clause 5.6.6 of the Code.

In Chapter 2, the Directlink asset and its technical service were described in terms of Directlink's ability to alleviate an inter-regional constraint and to satisfy network performance requirements.

In this Chapter 4:

- comparable network and non-network alternatives that could alleviate the emerging network constraints listed in section 2.3 have been identified—these alternatives include interconnectors, generation options, demand side options, and options involving other transmission and distribution network augmentations;
- the costs and benefits of each feasible comparable alternative have been estimated for a range of credible market development scenarios and sensitivity scenarios in accordance with the principles contained in the Regulatory Test;
- these alternatives have been ranked for each scenario; and
- the project that maximises the market benefits to all those who produce, consume and transport electricity in the NEM in most but not all the credible market scenarios is the project that satisfies the Regulatory Test.

4.2 Commercial discount rate

The Regulatory Test requires a commercial discount rate to be used to calculate the present value of future benefits and costs, that is, a 'discount rate appropriate for the analysis of a private enterprise investment in the electricity sector'.[26] Its intention is to ensure that 'the relevant discount rate recognises regulated and unregulated investments in a competitively neutral manner'.[27] The Regulatory Test also requires sensitivities to be tested for all key inputs, which include the discount rate.

[26] Revised Regulatory Test, p.10.
[27] ibid., p. 47.

Accordingly, the Regulatory Test requires the use of a discount rate that reflects the cost of capital associated with investments in the unregulated activities in the electricity supply industry—retailing, generation and like activities. However, prior to the Murraylink decision, most of the discount rates used when applying the Regulatory Test were simple estimates that were not justified by any objective estimate of the cost of capital for the relevant activities.

In applying the Regulatory Test, the Directlink Joint Venturers proposed to use a commercial discount rate that has been estimated with reference to capital market information, following the same methodology that has been used to estimate the cost of capital of Murraylink's prescribed service. As judgement is required in interpreting some market evidence, the Directlink Joint Venturers have also had regard to the discount rates adopted in other applications of the Regulatory Test.

(a) Industry-wide parameters

Most of the inputs to a commercial discount rate are industry-wide parameters, that is, parameters that would be the same across regulated and non-regulated activities and which cannot easily be observed from market evidence (and hence tend not to be updated mechanistically). For these parameters, it is proposed to apply the same input values that were adopted in the estimation of the regulatory cost of capital, that is:

- nominal and real risk free rates of 5.54 per cent and 2.94 per cent, respectively, and an implied inflation forecast of 2.53 per cent;
- market risk premium of 6 per cent; and
- value of imputation credits ('gamma') of 0.50.

The derivation of these parameters is explained in section 5.4. It is noted that these input parameters are consistent with the parameters that the Commission typically uses when estimating costs of capital for regulatory purposes.

The input assumptions that are dependent on the specific nature of a particular activity are:

- the financing assumptions (namely, the assumed gearing level and cost of debt);
- the beta; and
- the effective tax rate.

The assumptions adopted for these inputs are discussed in turn.

(b) Debt margin and capital structure

The commercial discount rate proposed by the Directlink Joint Venturers assumes a benchmark gearing ratio of 40 per cent debt-to-assets for the unregulated activities in the electricity supply industry, and that an unregulated entity with this credit rating could maintain a credit rating of BBB+. This gearing level is substantially lower than the 60 per cent gearing level assumed for the Directlink's regulated activities (refer section 5.3(d)). The difference reflects the likelihood that the greater variance in cash flows for the unregulated activities may not permit the same level of debt financing as that of the regulated activities.

As with the estimation of the regulatory cost of capital, the benchmark debt margin—that is, the yield in excess of Government bonds—has been calculated with reference to the long term average of the yields predicted by the CBASpectrum service for 10 year, BBB+ rated debt. This method provides a benchmark debt margin of 1.50 per cent, implying a cost of debt of 7.18 per cent.

(c) Equity beta

In the Murraylink application, the proxy equity beta was derived as the simple average of the observed equity betas for the firms listed on the Australian Stock Exchange whose primary activities were in the unregulated activities in the Australian electricity market. The firms that were used as comparable entities, and the most recent beta estimates are set out in the table below.

Table 4.1

SIMPLE AVERAGE OF THE OBSERVED EQUITY BETAS FOR THE FIRMS LISTED ON THE AUSTRALIAN STOCK EXCHANGE (DEBT BETA = 0)

Company	Equity beta	Gearing	Relevered equity beta (40% D/V)	Relevered equity beta (60% D/V)
Energy Developments	1.82	57%	1.30	1.96
Energy World	1.13	82%	0.34	0.51
Pacific Energy	0.40	25%	0.50	0.75
Pacific Hydro	2.19	4%	3.50	5.26
Origin Energy	0.75	19%	1.01	1.52
Horizon Energy	1.02	92%	0.14	0.20
Simple average	0.94	46%	1.13	1.70

Source: September 2003 Australian Graduate School of Management Risk Management Service beta estimates.

For the purpose of estimating the commercial discount rate, the simple average of the betas from all of the firms in the set of comparable entities has been used, implying a relevered equity beta of 1.13 for the assumed gearing level of 40 per cent debt to assets.

Table 4.1 also shows that the relevered equity beta that would be consistent with a target gearing level of 60 per cent debt to assets would be 1.70. This equity beta compares to the equity beta of 1.13 that was assumed for Directlink's regulated activities, implying that it has been assumed that the unregulated activities in the Australian electricity supply industry have a substantially higher level of risk than the regulated activities.

(d) Real pre-tax discount rate

The commercial discount rate that has been used in this Application has been expressed as a real pre-tax WACC, following the practice that has been applied in previous applications of the Regulatory Test, including the Commission's Murraylink decision. The use of a post-tax WACC and explicit modelling of taxation would add substantially to the complexity of applying the Regulatory Test, for little benefit.

The real pre-tax discount rate has been calculated using the forward-transformation, that is, grossing-up the 'Officer' version of the post-tax nominal WACC for taxation, and then deducting inflation (using the Fisher transformation). Accordingly, it has been assumed that the effective tax rate is equal to the statutory tax rate.

(e) Estimate of the commercial discount rate – base case

Based on the above estimates of the relevant parameters, the commercial discount rate to be applied in this Application is estimated to be 8.76 per cent, which has been rounded off to 9 percent per annum.

The parameters adopted are set out in the table below in Table 4.2 below.

Table 4.2

PARAMETERS TO DETERMINE COMMERCIAL DISCOUNT RATE

Parameter	Value
Nominal risk-free rate	5.54%
Real risk-free rate	2.94%
Implied inflation rate	2.53%
Equity beta	1.13
Market risk premium	6.00%
Debt margin	1.50%
Gearing (debt/assets)	40%
Corporate tax rate	30%
Value of imputation credits	50%
Nominal post-tax cost of equity	12.32%
Real post-tax cost of equity	9.55%
Nominal cost of debt	7.04%
Real cost of debt	4.40%
Nominal pre-tax discount rate	11.52%
Real pre-tax discount rate	8.76%

This estimate is consistent with the discount rate accepted by the Commission in its Murraylink decision and falls within the range of discount rates applied in previous applications of the Regulatory Test:

- the discount rate applied by NEMMCO in its SNI analysis was a real pre-tax discount rate of 11 per cent[28];
- VENCorp in its Latrobe to Melbourne study applied a real pre-tax discount rate of 8 per cent[29]; and
- Powerlink Queensland in its application for a proposed new network asset (Darling Downs Area) used a commercial discount rate of 10 per cent[30].

[28] NEMMCO*, IRPC Stage 1 Report Update, Proposed SNI Interconnector*, November 2000, p. 29.

[29] VENCorp, *Update on the Economics of Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity,* April 2003, p. 4.

[30] Powerlink Queensland, *Application Notice: Proposed New Large Network Asset – Darling Downs Area,* 31 March 2003, p. 23.

4.3 Reference date

The Directlink Joint Venturers have assumed that conversion could occur on 1 July 2005. Accordingly, all costs and benefits are calculated as net present values in July 2005 dollars unless indicated otherwise.

4.4 Timing of the alternative projects

The Regulatory Test requires that alternative timings be considered for the alternative projects. However, there is an immediate need for networks in the Gold Coast and the New South Wales far north coast areas to be augmented to meet network performance standards, and additional network limitations are being forecast for Queensland in 2005[31] and for New South Wales in 2006[32]. For the purpose of this Application, we have assumed that all the alternative projects must be commissioned and, where applicable, capable of providing pre-contingency network support by January 2005.

This timing imperative has motivated Powerlink to promptly complete negotiations with the Directlink Joint Venturers for a contract to provide 167 MW of network support capacity to the Gold Coast area from October 2005.

4.5 Methodologies

(a) Selection of alternative projects

BRW has selected a range of reasonable alternatives that could be considered as reasonable substitutes to Directlink as a regulated interconnector. In summary, BRW applied the following principles to its choice of alternative projects. The alternative projects:

- are to be relevantly substitutable for Directlink but not necessarily equivalent;
- should attempt to address in part some of the existing and emerging local network constraints identified by the TNSPs;
- should make use of commercially available current technology;
- are to have real power transfer capabilities consistent with the limitations of the surrounding network infrastructure and not necessarily the same as Directlink;
- reactive power transfer capability necessary to make each alternative technically feasible;

[31] Powerlink Queensland, *Emerging Transmission Network Limitations – Electricity Transfer to the Gold Coast and Tweed Area*, August 2003, p. 19.
[32] TransGrid, *Emerging Transmission Network Limitations on the New South Wales Far North Coast*, August 2003, p. 9.

- use enhanced control schemes to an extent where the benefits exceed the cost of the control scheme and are technically acceptable; and
- shall cost-effectively address environmentally sensitive areas to the minimum extent necessary to gain environment and planning approval.

To inform its costing estimates, BRW commissioned URS to:

- examine in detail the available transmission line route options for the alternative project to Directlink;
- prepare a desk-top assessment of the environmental and social constraints affecting the transmission corridor; and
- Identify the best and one additional route that are considered to have the minimum environmental mitigation measures necessary for there to be a reasonable probability of planning approval.

The URS report was subsequently reviewed by ERM, another leading planning and environmental specialist currently working on a number of Country Energy and other power line development projects in New South Wales, to provide an independent view of the issues identified. ERM confirmed the substance of the URS report. Further, copies of the report were also forwarded to the Department of Infrastructure, Planning and Natural Resources, Byron Council and Tweed Council for reference and to provide a basis for comments on the factors considered and the conclusions reached. At the time of finalising of the BRW report, only Tweed Council had been able to respond. The Council confirmed that the report identified and addressed the environmental and planning issues relevant to the project and study area.[33] The Council also indicated that the report provided a good assessment of the issues and regulatory requirements considered significant to the project.

(b) Estimation of benefits associated with network augmentation deferral

Network augmentation deferral benefits arise from the extent to which a project can defer or avoid the 'default reliability augmentations'—that is, further network augmentations that would be necessary for Powerlink and TransGrid to met their network performance standards.

To determine the network augmentation deferral benefits of each alternative project, the Application considers the future investment scenarios With and Without the alternative project in place. The network augmentation deferral benefit has been calculated as the difference between the discounted capital expenditure cash flows for those cases.

[33] This letter from Tweed Council is contained in Appendix F of this Application.

(c) Estimation of benefits associated with inter-regional power flows

A range of different types of benefits may arise from a project's ability to enable inter-regional power flows. TEUS modelled the NEM with and without each alternative project with PROSYM and MARS software and calculated the economic benefits of the alternative project over 40 years, in 4 categories:

Energy benefits

Energy benefits are the fuel savings made possible by a more efficient dispatch of generators to serve load made possible by an interconnector that increases inter-regional transfer capability.

An alternative project's energy benefits were calculated as the difference between the PROSYM estimates of total NEM fuel costs with and without the project.

Merchant entry generation deferral benefits

Merchant entry generation deferral benefits are the benefits of deferring the investment in profitable new generation. By more closely linking two regions, an interconnector project would tend to make better use of existing generation capacity and so moderate prices in the two regions. Lower prices would make the entry of new generation less attractive, and would tend to defer market entry until load growth pushes prices up to the level that would support new entry—that is, make new generation profitable.

PROSYM was used to determine a schedule of the expected entry of market (or merchant) generation with and without each alternative project, which each imply a specific cash flow, based on the type, timing, construction cost and operating cost of the new market generation. The merchant entry deferral benefit is the difference between the discounted capital expenditure cash flows for those cases.

Reliability entry generation deferral benefits

Reliability entry generation deferral benefits are the benefits of deferring the investment in new generation that NEMMCO might procure in its role as reserve trader to ensure that expected unserved energy remains less that the reliability set by the Reliability Panel. That is, NEMMCO role of reserve trader has been assumed to continue over the period that TEUS modelled.

Residual reliability benefits

Residual reliability benefits reflect the economic benefits flowing from a further reduction in unserved energy. An interconnector project connecting two regions where one has significant surplus generation, or where there is load diversity between the regions, allows for the sharing of generation reserves. For a given generation inventory, the ability to share reserves would reduce the number and duration of occasions where regional demand exceeds available supply—that is, unserved energy.

TEUS used the General Electric MARS model to determine the level of expected unserved energy in the NEM with and without each alternative project.

(d) Costing of alternative projects

BRW estimated the capital and operating costs of each alternative project based on detailed project scopes and using BRW's internal database of component costs and advice from the Directlink Joint Venturers on the actual costs of Directlink, which BRW reviewed and considered. The project costs are designed to reflect the full cost to a network owner for the design, development, construction and operation of the asset.

The base cost of each project can be divided into three asset cost categories: switchyard, transmission and easement costs. To estimate the full cost of an engineering, procurement and construction ('**EPC**') contract, BRW has added profit and overhead and the contractor's contingency. To the total contract cost, BRW added interest during construction ('**IDC**')[34], which has been calculated as the cost of financing each project to completion with consideration for the expected expenditure timetable for the project at the commercial discount rate.

BRW also estimated the life-cycle operating and maintenance ('**O&M**') costs for each alternative.

4.6 The alternative projects

BRW initially identified seven alternative projects that have 'a level of similarity' with Directlink.

Alternative 0 – Directlink

Alternative 0 is the Directlink project.

Directlink uses first generation HVDC Light technology with 3 units each with a nominal 60 MW capacity to provide active and reactive power support to the Queensland Gold Coast and far north eastern New South Wales networks, to relieve local thermal and voltage constraints, and to provide a controlled two-way interconnection between the Queensland and New South Wales regions.

The actual cost of Directlink is well below the present market value of the technology and that the cost of replacing Directlink today would be substantially more. Alternative 0 includes the actual cost of Directlink rather than the current market value of the HVDC Light technology as represented in Alternative 1.

Alternative 1 – HVDC Light with modified construction

Alternative 1 is a modern HVDC Light link (or equivalent) with a nominal 180 MW capacity (to match approximately the capability of the surrounding network) to provide

[34] IDC is also sometimes described as 'finance during construction' or incorporated as 'accumulated funds expended during construction'.

active and reactive power support to the Queensland Gold Coast and far north eastern New South Wales networks to relieve local thermal and voltage constraints and to provide a controlled two-way interconnection between the Queensland and New South Wales regions. Second generation converter design (developed since the installation of Directlink) would be employed rather than the first generation design that was used for Directlink

Alternative 1 also includes:

- sites established at Bungalora and Mullumbimby for the converter stations;
- protection and control systems to National Electricity Code standards including dynamic active and reactive power support; and
- a transmission line between Mullumbimby and Terranora that would be underground or in metal ducting for its entire length, which is required for the implementation of HVDC Light technology because of the susceptibility of the HV transistor equipment at the converter stations to lightning.

Alternative 2 – Conventional HVDC

Alternative 2 is a conventional high voltage DC link with 180 MW capacity to provide active power support to the Queensland Gold Coast and far north eastern New South Wales networks to relieve local thermal constraints and to provide a controlled two-way interconnection between the Queensland and New South Wales regions.

Alternative 2 also includes:

- a synchronous condenser and switched shunt capacitor installations (incorporated with the converter station filtering) on each side of the high voltage DC link to provide reactive power support to the Gold Coast and far north eastern New South Wales networks to relieve local voltage constraints;
- sites established at Bungalora and Mullumbimby for the converter stations.
- protection and control systems to Code standards.
- a transmission line route between Mullumbimby and Terranora would be as recommended by URS Australia[35] as the best route with undergrounding only included to the extent necessary to achieve the requisite environmental and planning approvals.

Alternative 3 – AC with phase shifting transformer

Alternative 3 is a 180 MW high voltage AC link with a 132 kV/110 kV phase shifting transformer comprising of three single phase units[36] with a ±30 degree tapping range

[35] URS Australia Pty Ltd, *Alternative Projects to the Directlink Transmission Line – Environmental Review: Mullumbimby to Terranora (New South Wales)* (‘**URS Report**’), 9 March 2004, contained in Appendix E.

at the Queensland end. The inclusion of a phase shifting transformer enables power to be forced across Alternative 3 to its maximum value for a wide range of conditions on QNI.

Alternative 3 also includes:

- a site established at Bungalora for the transformer;
- small switched shunt capacitor installations on each side of the AC link to provide local post-contingent voltage support for each side of the link;
- protection and control systems to Code standards;
- control capability to adjust the transformer phase angle to alleviate network constraints;
- modifications to the existing substations at each end; and
- a transmission line route between Mullumbimby and Terranora would be as recommended by URS Australia as the best route with undergrounding only included to the extent necessary to achieve the requisite environmental and planning approvals.

Alternative 4 – AC with conventional transformer

Alternative 4 is a 250 MVA high voltage AC link with a conventional 132 kV/110 kV auto-transformer with three single phase units at the Queensland end to provide active power support to the 110 kV Gold Coast network at Terranora and to the 132 kV far north eastern New South Wales network at Mullumbimby and to provide an uncontrolled, two-way interconnection between the Queensland and New South Wales regions.

Alternative 4 also includes:

- a site established at Bungalora for the transformer;
- switched shunt capacitors on each end of the AC link to provide local voltage support on each side of the link;
- protection and control systems to Code standards;
- modifications to the existing substations at each end, namely at Terranora and Mullumbimby will be required for cable connections with protection, control and communication modifications; and
- a transmission line route between Mullumbimby and Terranora would be as recommended by URS Australia as the best route with undergrounding only

[36] Transportation issues dictate the use of single phase units.

included to the extent necessary to achieve the requisite environmental and planning approvals.

The sharing of load between QNI and Alternative 4 is purely based on the (passive) network impedances connecting them, and as this alternative has no phase shifting transformer, the thermal rating of Alternative 4 must be 250 MVA (with sufficient VArs to maintain terminal voltages) in order that QNI can still transfer its rated power flow. However, given its dependence upon the level and direction of flow across QNI, Alternative 4 is unable to satisfy network performance standards in the Gold Coast and northern New South Wales areas for some period of time. For this reason, BRW has concluded that Alternative 4 is not a reasonable substitute for Directlink for the purposes of the Regulatory Test.

Alternative 5 – Separate HVAC augmentations in New South Wales and Queensland

Alternative 5 consists of the next tranche of high voltage AC network augmentations in the Gold Coast and New South Wales that would address the emerging network limitations in those areas due to load growth in the absence of Directlink or its alternative projects:

- the new 275 kV Greenbank switchyard with a new double circuit 275 kV AC line linking the new Greenbank switchyard with the existing Molendinar substation. This reliability augmentation is needed to provide active and reactive power support to the Gold Coast network to relieve the present local thermal and voltage constraints. .

- a new 330 kV AC line in New South Wales linking Dumaresq substation with Lismore substation to provide active and reactive power support to the far north eastern New South Wales network to relieve present local thermal and voltage constraints. The new line is required to provide continuity of supply to Lismore following the most critical outage, namely the loss of the existing Armidale to Lismore 330 kV line (Line 89).

Based on currently available information, BRW found that Alternative 5 be is the same project that Powerlink and TransGrid would pursue to meet their reliability obligations if Directlink was not in place.

For the purposes of this application of the Regulatory Test, Alternative 5 as the default reliability augmentations has been taken to be the baseline project—that is, the project with which the other alternative projects and their market benefits are compared.

Alternative 6 – Generation and demand side management

Alternative 6 consists of approximately 180 MW of embedded generation in the Gold Coast and far north east of New South Wales, and a demand management program, in addition to embedded generation and demand management already anticipated in the areas. Load forecasts presently published by the local network service providers already take into account committed and proposed embedded generation and demand side management schemes.

BRW concludes that there are significant impediments to the implementation of additional embedded generation and demand management project because:

- there is limited availability of fuel sources in the areas—particularly for gas powered generation, which would be optimal for deferring potential network augmentations;
- high environmental sensitivity of the region makes it very difficult to obtain planning permits for new generation plants;
- augmentation of the distribution networks may be required to accommodate the increased fault levels that result from embedded generation, particularly for generation plant of large size or in remote locations where the network may be relatively weak; and
- the nature of the load base in the area, and expected poor take-up rates, would make it difficult to implement and achieve desired levels of demand management, including voluntary load shedding schemes—180 MW is equivalent to approximately 60,000 small customers.

BRW concludes that significant impediments to the implementation of Alternative 6 render it technically and economically infeasible at this time and, therefore, Alternative 6 is not a reasonable alternative for the purpose of applying the Regulatory Test.

4.7 Costs, benefits and rankings of the alternative projects

For this Application, the Directlink Joint Venturers have examined the costs and benefits for each of the alternative projects.

(a) Credible market development scenarios

Of the 26 scenarios studied, scenarios 4, 5, 6, 11 12A and 12B are considered 'credible market development scenarios' and the remaining scenarios are sensitivity tests.

The credible market development scenarios involve different but reasonably possible schedules of entry of generation and network investment based on:

- the load growth expected from a high level of economic growth with generators bidding based upon a proxy for their LRMCs and expected costs of the alternative projects (scenario 4);
- the load growth expected from a medium level of economic growth with generators bidding based upon a proxy for their LRMCs and expected costs of the alternative projects (scenario 5);

- the load growth expected from a low level of economic growth with generators bidding based upon a proxy for their LRMCs and expected costs of the alternative projects (scenario 6);
- the load growth expected from a medium level of economic growth with generators bidding based upon their SRMCs and expected costs of the alternative projects (scenario 11)
- the load growth expected from a medium level of economic growth with generators bidding based upon a proxy for their LRMCs and costs of the alternative projects 10% higher than expected (scenario 12A); and
- the load growth expected from a medium level of economic growth with generators bidding based upon a proxy for their LRMCs and costs of the alternative projects 10% lower than expected (scenario 12B).

The capital costs of Alternative 0 in scenarios 12A and 12B are the actual capital costs and only the estimated O&M costs were varied by 10%.

Scenario 5 is the most credible scenario, that is, the scenario that includes the best estimate of expected economic growth, a proxy for LRMC generator bidding, and alternative project costs. Scenarios 4, 6, 11, 12A and 12B are single variations of one of these parameters.

All scenarios examined include Basslink as a committed project. A list of committed and anticipated projects is included in the TEUS and BRW reports.

(b) Value of unserved energy

The credible market development scenarios used a value of unserved energy of $29,600 per MWh.

The Directlink Joint Venturers agree with TEUS that the most extensive and recently published evidence[37] suggests that unserved energy is accurately valued at $29,600 per MWh for the purposes of transmission planning—and applications of the Regulatory Test, in particular. In support of this view, the Directlink Joint Venturers note that the Commission clarifies in its Revised Regulatory Test the need to recognise the value of reductions in loss load (VENCorp's value of customer reliability or '**VCR**') that VENCorp currently sets at $29,600 per MWh.[38]

(c) Sensitivity testing

For the purposes of sensitivity testing, the relative net market benefits of the alternative projects were also calculated with regard to:

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[37] VENCorp, *Response to Submissions: Final Report – Value of Unserved Energy to be used by VENCorp for Electricity Transmission Planning*, 23 May 2003.

[38] Australian Competition and Consumer Commission, *Final Decision: Revenue of Regulatory Test for network augmentations* ('**Revised Regulatory Test**'), 11 August 2004, p. 9.

- a 7% and 11% per annum commercial discount rates;
- a value of USE of $10,000 per MWh.

In relation to the range of commercial discount rates considered in this Application, the following precedents have been set:

- Murraylink decision—the base case commercial discount rate was 9 per cent, with an lower and upper range of 6.72 per cent and 10.27 per cent[39];
- NEMMCO's SNI assessment—the base case commercial discount rate was 11 per cent with sensitivities at 9 per cent and 13 per cent[40];
- VENCorp's assessment of the Latrobe to Melbourne augmentation—the base case commercial discount rate was 8 per cent with sensitivities at 6 per cent and 10 per cent[41]; and
- Powerlink Queensland's assessment of its proposed new network asset in the Darling Downs Area—the base case commercial discount rate was 10 per cent with sensitivities at 8 per cent and 12 per cent[42].

Given this previous practice, the Directlink Joint Venturers will apply a range of plus and minus 2 percentage points around the base case estimate for the purpose of undertaking sensitivity analyses for the application of the Regulatory Test to Directlink.

(d) Costs of the alternative projects

As described in section 4.5(d), the costs of the alternative projects consist of four principal components:

- the capital cost—based on BRW's estimate of the price of an EPC contract;
- interest during construction; and
- life-cycle O&M costs.

The total costs of the alternative projects vary with the commercial discount rate. This is because the IDC and life-cycle O&M costs are cash flows over time and their present values vary with the assumed rate.

The cost of Alternative 5 also varies with the load growth rate because the load growth rate determines the timing of the New South Wales component of the alternative. For medium and low economic growth, the New South Wales component of Alternative 5

[39] Murraylink decision, p. 84.
[40] NEMMCO, *IRPC Stage 1 Report Update, Proposed SNI Interconnector*, November 2000, p. 29.
[41] Powerlink Queensland, *Application Notice: Proposed New Large Network Asset – Darling Downs Area,* 31 March 2003, p. 23.
[42] VENCorp, *Update on the Economics of Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity,* April 2003, p. 4.

would be required as a reliability augmentation for the summer of 2006-07. In the case of high economic growth, the New South Wales component of Alternative 5 would be required as a reliability augmentation for the summer of 2005-06. Bringing the New South Wales component forward would increase the cost of Alternative 5 in present value terms.

While the costs of the alternative project for each modelling scenario are listed in Table 4.7, a summary is provided below in Table 4.3:

Table 4.3

TOTAL COSTS OF THE ALTERNATIVE PROJECTS FOR MEDIUM ECONOMIC GROWTH ($M)

	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
Discount rate	Total Cost	Total Cost	Total Cost	Total Cost	Total Cost
11%	191.1	282.6	181.7	100.5	225.6
9%	196.3	284.9	184.6	103.8	231.4
7%	203.8	289.5	189.8	109.2	239.6.9

Source: BRW Report.

(e) Benefits of the alternative projects

As described in sections 4.5(b) and 4.5(c), two types of market benefits have been estimated for the alternative projects:

- Network deferral market benefits; and
- Inter-regional market benefits.

In both cases the benefits of the alternative projects have been calculated as the increased (or decreased) benefits that the project would provide compared to Alternative 5.

The network deferral benefits of each alternative project for each scenario are set out in Table 4.7. The network deferral benefits of each project vary with the discount rate, which varies the cost of the default reliability augmentation and the level of economic growth. High economic growth induces higher load growth, shorter deferral periods and, therefore, lower deferral benefits.

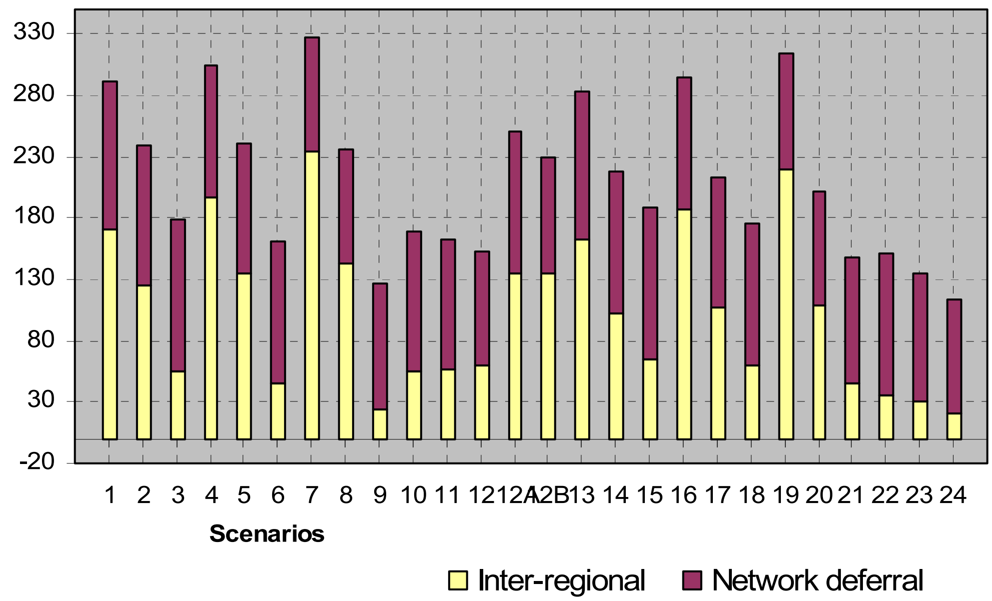
The inter-regional benefits of each alternative project for each scenario are set out in Table 4.8. The inter-regional benefits of each project vary in a complex way with the assumed value of unserved energy, level of economic growth, generator bidding strategy, and commercial discount rate.

Alternative 0, 1, and 2 provide the same network deferral benefits and the same inter-regional benefits.

The inter-regional benefits and the network deferral benefits of the Alternatives, in effect, partially counter-balance one another. This effect results in fairly stable levels of total benefits for Alternatives 0, 1 and 2 for each scenario as illustrated in Figure 4.1.

Figure 4.1

TOTAL MARKET BENEFITS OF ALTERNATIVES 0, 1 AND 2 ($M)

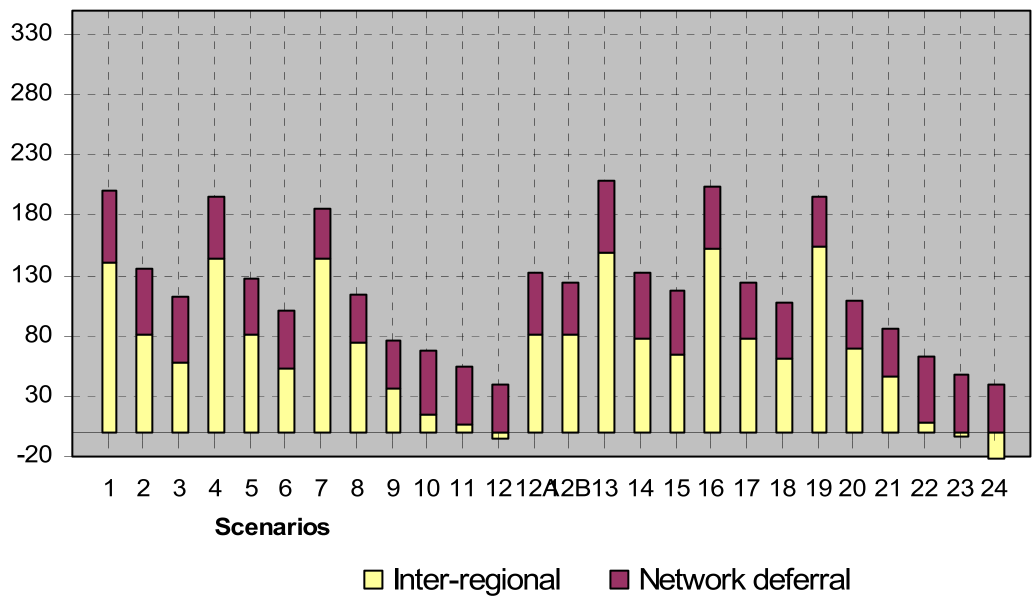


Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group.

The market benefits of Alternative 0, 1 and 2 are relatively more stable and much higher for the scenarios studies than for Alternative 3, as see in Figure 4.2.

Figure 4.2

TOTAL MARKET BENEFITS OF ALTERNATIVE 3 ($M)



Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group.

Alternative 3 provides substantially less market benefits than Alternatives 0, 1 and 2 because it is significantly technically inferior:

- Alternative 3 has limited ability to be dispatched in the opposite direction to QNI, and this limitation reduces its ability to defer the next tranche of network support augmentations for the Gold Coast and far north east of New South Wales; and

- Alternative 3 uses AC technology, while Alternatives 0, 1, and 2 used HVDC technology. The two technologies have different loss functions, which lead to slight differences in generation dispatch, market prices, and ultimately in market entry schedules.

- The network augmentation deferral periods are shorter for Alternative 3 than for Alternatives 0, 1, and 2. Changes in deferral periods causes changes over time in the sub-regional interface limits. Along with the different market entry schedule, this affects the timing and location of reliability entry plant and residual unserved energy.

Alternative 5 has no inter-regional benefits because it includes no inter-regional link. All its benefits are derived from the fact that if Alternative 5 was built, it would permanently defer the default reliability augmentations—which are effectively the same as Alternative 5—in perpetuity. Thus, the total market benefits of Alternative 5 are equal to its estimated cost.

Indicative total benefits for each of the projects given a 9% discount rate, LRMC bidding and medium load growth (scenario 5) is below in Table 4.4.

Table 4.4

SAMPLE MARKET BENEFITS OF THE ALTERNATIVE PROJECTS—SCENARIO 5 ($M)

	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
Type of market benefits	Market benefits	Market benefits	Market benefits	Market benefits	Market benefits
Network deferral	105.0	105.0	105.0	47.2	231.4
Inter-regional	135.1	135.1	135.1	81.1	0.0
Total	240.1	240.1	240.1	128.3	231.4

Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group. Note: Scenario 5 is a credible market development scenario that examines the case of $29,600 per MWh value of USE, 9% discount rate, LRMC bidding, and medium economic growth. 'Market benefits' means net market benefits relative to Alternative 5, expressed in $M.

(f) Relative net market benefits of the alternative projects

As mentioned in section 4.5(d), the default reliability augmentations are the baseline project with which the market benefits of the other alternative projects are compared. That is, the net market benefits—total benefits minus total costs—that have been calculated for the alternative projects are the marginal benefits that each project would provide to the NEM over those that the default reliability augmentations would provide.

The net market benefits relative to the default reliability augmentations for each of alternative projects, the credible market development scenarios and sensitivities tests are contained in Table 4.11 and Table 4.12 indicate the rankings of the projects for each scenario. The first ranking project has the highest net market benefits.

These tables show that Alternative 2 is more attractive than the alternative projects for the credible market development scenarios, as shown in Table 4.5. That is Alternative 2 provides maximum net market benefits in scenarios 4, 5 and 12B by a substantial margin.

Table 4.5

PROJECT RANKINGS FOR CREDIBLE MARKET DEVELOPMENT SCENARIOS

No.	Gen. bid	DR	Econ. growth	Proj. cost	1st ranking		2nd ranking		3rd ranking		4th ranking		5th ranking	
					Proj	RNB	Proj	RNB	Proj	RNB	Proj	RNB	Proj	RNB
4	LRMC	9%	High	100%	Alt 2	120.3	Alt 0	108.6	Alt 3	92.1	Alt 1	20.0	Alt 5	0.0
5	LRMC	9%	Med	100%	Alt 2	55.5	Alt 0	43.8	Alt 3	24.5	Alt 5	0.0	Alt 1	-44.8
6	LRMC	9%	Low	100%	Alt 5	0.0	Alt 3	-3.4	Alt 2	-24.3	Alt 0	-36.0	Alt 1	-124.6
11	SRMC	9%	Med	100%	Alt 5	0.0	Alt 2	-22.4	Alt 0	-34.1	Alt 3	-49.6	Alt 1	-122.7
12A	LRMC	9%	Med	110%	Alt 0	51.2	Alt 2	47.5	Alt 3	18.8	Alt 5	0.0	Alt 1	-62.8
12B	LRMC	9%	Med	90%	Alt 2	63.5	Alt 0	36.4	Alt 3	30.2	Alt 5	0.0	Alt 1	-26.8

Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group. Note: 'RNB' means net market benefits relative to Alternative 5, expressed in $M.

(g) Results of sensitivity testing

As shown in Table 4.11 and Table 4.12, of the 20 sensitivity scenarios studied, Alternative 2 maximises the net market benefits in 9 cases and has the second highest net market benefits in 7 cases.

Table 4.6 also shows that the average net market benefits for the sensitivity scenarios are similar to the credible market development scenarios—which demonstrates the robustness of the calculation methodology and input assumptions.

Table 4.6

OUTCOMES OF SENSITIVITY TESTING—RELATIVE NET MARKET BENEFITS ($M)

	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
Type of market benefits	RNB	RNB	RNB	RNB	RNB
Average of credible scenarios	28.3	-60.3	40.0	18.8	0.0
Average of sensitivity scenarios	10.0	-74.3	21.2	12.0	0.0
Average of all scenarios	14.6	-74.0	26.3	14.0	0.0

Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group. Note: 'RNB' means net market benefits relative to Alternative 5, expressed in $M.

For Alternatives 0, 1, and 2, TEUS found that the inter-regional market benefits are less sensitive to the value of USE than originally anticipated. A review of its results shows that, once the 0.002% USE reliability criteria is met by the addition of appropriate amounts of reliability entry plant, there is little USE left to value at either $29,600 per MWh or $10,000 per MWh. However, the selection of the value of USE remains important because the market benefits of Alternative 3 are sensitive to the choice of the value and, even for those less sensitive scenarios, the ranking of the alternatives can depend on a relatively small marginal difference between net market benefits.

4.8 Does an alternative project satisfy the Regulatory Test?

These results demonstrate that Alternative 2 maximises the market benefits to all those who produce, consume and transport electricity in the NEM in most but not all the credible market scenarios examined.

Therefore, Alternative 2 would pass the Regulatory Test.

Table 4.7

TOTAL COSTS OF THE ALTERNATIVE PROJECTS FOR EACH SCENARIO ($M)

No.	Type of scenario	Value of USE	Gen. bidding	Disc. rate	Econ. growth	Alt proj cost	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
							Total cost	Total cost	Total cost	Total cost	Total cost
1	Sensitivity	29,500	LRMC	11%	High	100%	191.1	282.6	181.7	100.5	243.0
2	Sensitivity	29,500	LRMC	11%	Med	100%	191.1	282.6	181.7	100.5	225.6
3	Sensitivity	29,500	LRMC	11%	Low	100%	191.1	282.6	181.7	100.5	225.6
4	Credible	29,500	LRMC	9%	High	100%	196.3	284.9	184.6	103.8	245.9
5	Credible	29,500	LRMC	9%	Med	100%	196.3	284.9	184.6	103.8	231.4
6	Credible	29,500	LRMC	9%	Low	100%	196.3	284.9	184.6	103.8	231.4
7	Sensitivity	29,500	LRMC	7%	High	100%	203.8	289.5	189.8	109.2	251.3
8	Sensitivity	29,500	LRMC	7%	Med	100%	203.8	289.5	189.8	109.2	239.6
9	Sensitivity	29,500	LRMC	7%	Low	100%	203.8	289.5	189.8	109.2	239.6
10	Sensitivity	29,500	SRMC	11%	Med	100%	191.1	282.6	181.7	100.5	225.6
11	Credible	29,500	SRMC	9%	Med	100%	196.3	284.9	184.6	103.8	231.4
12	Sensitivity	29,500	SRMC	7%	Med	100%	203.8	289.5	189.8	109.2	239.6
12A	Credible	29,500	LRMC	9%	Med	110%	199.5	313.4	203.1	114.2	254.5
12B	Credible	29,500	LRMC	9%	Med	90%	193.2	256.4	166.2	93.4	208.2
13	Sensitivity	10,000	LRMC	11%	High	100%	191.1	282.6	181.7	100.5	243.0
14	Sensitivity	10,000	LRMC	11%	Med	100%	191.1	282.6	181.7	100.5	225.6
15	Sensitivity	10,000	LRMC	11%	Low	100%	191.1	282.6	181.7	100.5	225.6
16	Sensitivity	10,000	LRMC	9%	High	100%	196.3	284.9	184.6	103.8	245.9
17	Sensitivity	10,000	LRMC	9%	Med	100%	196.3	284.9	184.6	103.8	231.4
18	Sensitivity	10,000	LRMC	9%	Low	100%	196.3	284.9	184.6	103.8	231.4
19	Sensitivity	10,000	LRMC	7%	High	100%	203.8	289.5	189.8	109.2	251.3
20	Sensitivity	10,000	LRMC	7%	Med	100%	203.8	289.5	189.8	109.2	239.6
21	Sensitivity	10,000	LRMC	7%	Low	100%	203.8	289.5	189.8	109.2	239.6
22	Sensitivity	10,000	SRMC	11%	Med	100%	191.1	282.6	181.7	100.5	225.6
23	Sensitivity	10,000	SRMC	9%	Med	100%	196.3	284.9	184.6	103.8	231.4
24	Sensitivity	10,000	SRMC	7%	Med	100%	203.8	289.5	189.8	109.2	239.6

Source: BRW Report & The Allen Consulting Group

Table 4.8

NETWORK DEFERRAL BENEFITS OF THE ALTERNATIVE PROJECTS FOR EACH SCENARIO ($M)

No.	Type of Scenario	Value of USE	Gen. bidding	Disc. rate	Econ. growth	Alt proj cost	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
							Network def.	Network def.	Network def.	Network def.	Network def.
1	Sensitivity	29,500	LRMC	11%	High	100%	120.4	120.4	120.4	59.9	243.0
2	Sensitivity	29,500	LRMC	11%	Med	100%	114.7	114.7	114.7	53.9	225.6
3	Sensitivity	29,500	LRMC	11%	Low	100%	124.1	124.1	124.1	53.9	225.6
4	Credible	29,500	LRMC	9%	High	100%	107.8	107.8	107.8	51.5	245.9
5	Credible	29,500	LRMC	9%	Med	100%	105.0	105.0	105.0	47.2	231.4
6	Credible	29,500	LRMC	9%	Low	100%	114.9	114.9	114.9	47.2	231.4
7	Sensitivity	29,500	LRMC	7%	High	100%	93.1	93.1	93.1	42.5	251.3
8	Sensitivity	29,500	LRMC	7%	Med	100%	92.9	92.9	92.9	39.8	239.6
9	Sensitivity	29,500	LRMC	7%	Low	100%	103.0	103.0	103.0	39.8	239.6
10	Sensitivity	29,500	SRMC	11%	Med	100%	114.7	114.7	114.7	53.9	225.6
11	Credible	29,500	SRMC	9%	Med	100%	105.0	105.0	105.0	47.2	231.4
12	Sensitivity	29,500	SRMC	7%	Med	100%	92.9	92.9	92.9	39.8	239.6
12A	Credible	29,500	LRMC	9%	Med	110%	115.5	115.5	115.5	51.9	254.5
12B	Credible	29,500	LRMC	9%	Med	90%	94.5	94.5	94.5	42.5	208.2
13	Sensitivity	10,000	LRMC	11%	High	100%	120.4	120.4	120.4	59.9	243.0
14	Sensitivity	10,000	LRMC	11%	Med	100%	114.7	114.7	114.7	53.9	225.6
15	Sensitivity	10,000	LRMC	11%	Low	100%	124.1	124.1	124.1	53.9	225.6
16	Sensitivity	10,000	LRMC	9%	High	100%	107.8	107.8	107.8	51.5	245.9
17	Sensitivity	10,000	LRMC	9%	Med	100%	105.0	105.0	105.0	47.2	231.4
18	Sensitivity	10,000	LRMC	9%	Low	100%	114.9	114.9	114.9	47.2	231.4
19	Sensitivity	10,000	LRMC	7%	High	100%	93.1	93.1	93.1	42.5	251.3
20	Sensitivity	10,000	LRMC	7%	Med	100%	92.9	92.9	92.9	39.8	239.6
21	Sensitivity	10,000	LRMC	7%	Low	100%	103.0	103.0	103.0	39.8	239.6
22	Sensitivity	10,000	SRMC	11%	Med	100%	114.7	114.7	114.7	53.9	225.6
23	Sensitivity	10,000	SRMC	9%	Med	100%	105.0	105.0	105.0	47.2	231.4
24	Sensitivity	10,000	SRMC	7%	Med	100%	92.9	92.9	92.9	39.8	239.6

Source: BRW Report & The Allen Consulting Group. Note: 'Network def.' means market benefits derived from deferring the default reliability augmentations relative to Alternative 5.

Table 4.9

INTER-REGIONAL BENEFITS OF THE ALTERNATIVE PROJECTS FOR EACH SCENARIO ($M)

No.	Type of Scenario	Value of USE	Gen. bidding	Disc. rate	Econ. growth	Alt proj cost	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
							Inter-regional	Inter-regional	Inter-regional	Inter-regional	Inter-regional
1	Sensitivity	29,500	LRMC	11%	High	100%	170.5	170.5	170.5	141.6	0.0
2	Sensitivity	29,500	LRMC	11%	Med	100%	124.8	124.8	124.8	81.9	0.0
3	Sensitivity	29,500	LRMC	11%	Low	100%	54.2	54.2	54.2	58.2	0.0
4	Credible	29,500	LRMC	9%	High	100%	197.1	197.1	197.1	144.4	0.0
5	Credible	29,500	LRMC	9%	Med	100%	135.1	135.1	135.1	81.1	0.0
6	Credible	29,500	LRMC	9%	Low	100%	45.4	45.4	45.4	53.2	0.0
7	Sensitivity	29,500	LRMC	7%	High	100%	234.1	234.1	234.1	144.0	0.0
8	Sensitivity	29,500	LRMC	7%	Med	100%	143.4	143.4	143.4	73.8	0.0
9	Sensitivity	29,500	LRMC	7%	Low	100%	23.3	23.3	23.3	37.2	0.0
10	Sensitivity	29,500	SRMC	11%	Med	100%	55.1	55.1	55.1	14.6	0.0
11	Credible	29,500	SRMC	9%	Med	100%	57.2	57.2	57.2	7.0	0.0
12	Sensitivity	29,500	SRMC	7%	Med	100%	59.4	59.4	59.4	-5.1	0.0
12A	Credible	29,500	LRMC	9%	Med	110%	135.1	135.1	135.1	81.1	0.0
12B	Credible	29,500	LRMC	9%	Med	90%	135.1	135.1	135.1	81.1	0.0
13	Sensitivity	10,000	LRMC	11%	High	100%	162.7	162.7	162.7	149.3	0.0
14	Sensitivity	10,000	LRMC	11%	Med	100%	102.9	102.9	102.9	78.7	0.0
15	Sensitivity	10,000	LRMC	11%	Low	100%	65.3	65.3	65.3	64.2	0.0
16	Sensitivity	10,000	LRMC	9%	High	100%	187.0	187.0	187.0	153.1	0.0
17	Sensitivity	10,000	LRMC	9%	Med	100%	107.9	107.9	107.9	77.7	0.0
18	Sensitivity	10,000	LRMC	9%	Low	100%	60.5	60.5	60.5	60.8	0.0
19	Sensitivity	10,000	LRMC	7%	High	100%	220.4	220.4	220.4	153.7	0.0
20	Sensitivity	10,000	LRMC	7%	Med	100%	108.4	108.4	108.4	69.9	0.0
21	Sensitivity	10,000	LRMC	7%	Low	100%	44.5	44.5	44.5	47.2	0.0
22	Sensitivity	10,000	SRMC	11%	Med	100%	35.8	35.8	35.8	8.9	0.0
23	Sensitivity	10,000	SRMC	9%	Med	100%	30.4	30.4	30.4	-3.0	0.0
24	Sensitivity	10,000	SRMC	7%	Med	100%	20.1	20.1	20.1	-22.1	0.0

Source: TEUS Supplementary Report. Note: 'Inter-regional.' means the inter-regional market benefits of the alternative project relative to those of Alternative 5.

Table 4.10

TOTAL MARKET BENEFITS FOR EACH SCENARIO ($M)

No.	Type of Scenario	Value of USE	Gen. bidding	Disc. rate	Econ. growth	Alt proj cost	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
							Total benefits	Total benefits	Total benefits	Total benefits	Total benefits
1	Sensitivity	29,500	LRMC	11%	High	100%	290.9	290.9	290.9	201.4	243.0
2	Sensitivity	29,500	LRMC	11%	Med	100%	239.5	239.5	239.5	135.8	225.6
3	Sensitivity	29,500	LRMC	11%	Low	100%	178.3	178.3	178.3	112.1	225.6
4	Credible	29,500	LRMC	9%	High	100%	304.9	304.9	304.9	195.9	245.9
5	Credible	29,500	LRMC	9%	Med	100%	240.1	240.1	240.1	128.3	231.4
6	Credible	29,500	LRMC	9%	Low	100%	160.3	160.3	160.3	100.4	231.4
7	Sensitivity	29,500	LRMC	7%	High	100%	327.3	327.3	327.3	186.5	251.3
8	Sensitivity	29,500	LRMC	7%	Med	100%	236.3	236.3	236.3	113.6	239.6
9	Sensitivity	29,500	LRMC	7%	Low	100%	126.3	126.3	126.3	77.0	239.6
10	Sensitivity	29,500	SRMC	11%	Med	100%	169.7	169.7	169.7	68.5	225.6
11	Credible	29,500	SRMC	9%	Med	100%	162.3	162.3	162.3	54.2	231.4
12	Sensitivity	29,500	SRMC	7%	Med	100%	152.3	152.3	152.3	34.6	239.6
12A	Credible	29,500	LRMC	9%	Med	110%	250.6	250.6	250.6	133.0	254.5
12B	Credible	29,500	LRMC	9%	Med	90%	229.6	229.6	229.6	123.6	208.2
13	Sensitivity	10,000	LRMC	11%	High	100%	283.1	283.1	283.1	209.2	243.0
14	Sensitivity	10,000	LRMC	11%	Med	100%	217.6	217.6	217.6	132.7	225.6
15	Sensitivity	10,000	LRMC	11%	Low	100%	189.4	189.4	189.4	118.2	225.6
16	Sensitivity	10,000	LRMC	9%	High	100%	294.8	294.8	294.8	204.6	245.9
17	Sensitivity	10,000	LRMC	9%	Med	100%	212.9	212.9	212.9	124.9	231.4
18	Sensitivity	10,000	LRMC	9%	Low	100%	175.4	175.4	175.4	108.1	231.4
19	Sensitivity	10,000	LRMC	7%	High	100%	313.5	313.5	313.5	196.2	251.3
20	Sensitivity	10,000	LRMC	7%	Med	100%	201.3	201.3	201.3	109.7	239.6
21	Sensitivity	10,000	LRMC	7%	Low	100%	147.5	147.5	147.5	86.9	239.6
22	Sensitivity	10,000	SRMC	11%	Med	100%	150.4	150.4	150.4	62.8	225.6
23	Sensitivity	10,000	SRMC	9%	Med	100%	135.4	135.4	135.4	44.2	231.4
24	Sensitivity	10,000	SRMC	7%	Med	100%	113.1	113.1	113.1	17.7	239.6

Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group.

Table 4.11

RELATIVE NET MARKET BENEFITS FOR EACH SCENARIO ($M)

No.	Type of Scenario	Value of USE	Gen. bidding	Disc. rate	Econ. growth	Alt proj cost	Alternative 0		Alternative 1		Alternative 2		Alternative 3		Alternative 5	
							RNB	Rank	RNB	Rank	RNB	Rank	RNB	Rank	RNB	Rank
1	Sensitivity	29,500	LRMC	11%	High	100%	99.8	3	8.3	4	109.2	1	100.9	2	0.0	5
2	Sensitivity	29,500	LRMC	11%	Med	100%	48.4	2	-43.1	5	57.8	1	35.3	3	0.0	4
3	Sensitivity	29,500	LRMC	11%	Low	100%	-12.8	4	-104.3	5	-3.4	3	11.6	1	0.0	2
4	Credible	29,500	LRMC	9%	High	100%	108.6	2	20.0	4	120.3	1	92.1	3	0.0	5
5	Credible	29,500	LRMC	9%	Med	100%	43.8	2	-44.8	5	55.5	1	24.5	3	0.0	4
6	Credible	29,500	LRMC	9%	Low	100%	-36.0	4	-124.6	5	-24.3	3	-3.4	2	0.0	1
7	Sensitivity	29,500	LRMC	7%	High	100%	123.5	2	37.8	4	137.5	1	77.3	3	0.0	5
8	Sensitivity	29,500	LRMC	7%	Med	100%	32.5	2	-53.2	5	46.5	1	4.4	3	0.0	4
9	Sensitivity	29,500	LRMC	7%	Low	100%	-77.4	4	-163.1	5	-63.4	3	-32.2	2	0.0	1
10	Sensitivity	29,500	SRMC	11%	Med	100%	-21.4	3	-112.9	5	-12.0	2	-32.0	4	0.0	1
11	Credible	29,500	SRMC	9%	Med	100%	-34.1	3	-122.7	5	-22.4	2	-49.6	4	0.0	1
12	Sensitivity	29,500	SRMC	7%	Med	100%	-51.5	3	-137.2	5	-37.5	2	-74.6	4	0.0	1
12A	Sensitivity	29,500	LRMC	9%	Med	110%	51.2	1	-62.8	5	47.5	2	18.8	3	0.0	4
12B	Sensitivity	29,500	LRMC	9%	Med	90%	36.4	2	-26.8	5	63.5	1	30.2	3	0.0	4
13	Sensitivity	10,000	LRMC	11%	High	100%	92.0	3	0.5	4	101.4	2	108.7	1	0.0	5
14	Sensitivity	10,000	LRMC	11%	Med	100%	26.5	3	-65.0	5	35.9	1	32.1	2	0.0	4
15	Sensitivity	10,000	LRMC	11%	Low	100%	-1.7	4	-93.2	5	7.7	2	17.7	1	0.0	3
16	Sensitivity	10,000	LRMC	9%	High	100%	98.4	3	9.8	4	110.1	1	100.8	2	0.0	5
17	Sensitivity	10,000	LRMC	9%	Med	100%	16.6	3	-72.0	5	28.3	1	21.1	2	0.0	4
18	Sensitivity	10,000	LRMC	9%	Low	100%	-20.9	4	-109.5	5	-9.2	3	4.3	1	0.0	2
19	Sensitivity	10,000	LRMC	7%	High	100%	109.8	2	24.1	4	123.8	1	87.0	3	0.0	5
20	Sensitivity	10,000	LRMC	7%	Med	100%	-2.5	4	-88.2	5	11.5	1	0.5	2	0.0	3
21	Sensitivity	10,000	LRMC	7%	Low	100%	-56.3	4	-142.0	5	-42.3	3	-22.3	2	0.0	1
22	Sensitivity	10,000	SRMC	11%	Med	100%	-40.7	4	-132.2	5	-31.3	2	-37.7	3	0.0	1
23	Sensitivity	10,000	SRMC	9%	Med	100%	-60.9	4	-149.5	5	-49.2	2	-59.6	3	0.0	1
24	Sensitivity	10,000	SRMC	7%	Med	100%	-90.7	3	-176.4	5	-76.7	2	-91.5	4	0.0	1

Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group. Note: 'RNB' means net market benefits relative to Alternative 5.

Table 4.12

RANKINGS OF ALTERNATIVE PROJECTS FOR EACH SCENARIO ($M)

No.	Type of Scenario	Value of USE	Gen. bidding	Disc. rate	Econ. growth	Alt proj cost	First rank		Second rank		Third rank		Fourth rank		Fifth rank	
							Proj	RNB	Proj	RNB	Proj	RNB	Proj	RNB	Proj	RNB
1	Sensitivity	29,500	LRMC	11%	High	100%	Alt 2	109.2	Alt 3	100.9	Alt 0	99.8	Alt 1	8.3	Alt 5	0.0
2	Sensitivity	29,500	LRMC	11%	Med	100%	Alt 2	57.8	Alt 0	48.4	Alt 3	35.3	Alt 5	0.0	Alt 1	-43.1
3	Sensitivity	29,500	LRMC	11%	Low	100%	Alt 3	11.6	Alt 5	0.0	Alt 2	-3.4	Alt 0	-12.8	Alt 1	-104.3
4	Credible	29,500	LRMC	9%	High	100%	Alt 2	120.3	Alt 0	108.6	Alt 3	92.1	Alt 1	20.0	Alt 5	0.0
5	Credible	29,500	LRMC	9%	Med	100%	Alt 2	55.5	Alt 0	43.8	Alt 3	24.5	Alt 5	0.0	Alt 1	-44.8
6	Credible	29,500	LRMC	9%	Low	100%	Alt 5	0.0	Alt 3	-3.4	Alt 2	-24.3	Alt 0	-36.0	Alt 1	-124.6
7	Sensitivity	29,500	LRMC	7%	High	100%	Alt 2	137.5	Alt 0	123.5	Alt 3	77.3	Alt 1	37.8	Alt 5	0.0
8	Sensitivity	29,500	LRMC	7%	Med	100%	Alt 2	46.5	Alt 0	32.5	Alt 3	4.4	Alt 5	0.0	Alt 1	-53.2
9	Sensitivity	29,500	LRMC	7%	Low	100%	Alt 5	0.0	Alt 3	-32.2	Alt 2	-63.4	Alt 0	-77.4	Alt 1	-163.1
10	Sensitivity	29,500	SRMC	11%	Med	100%	Alt 5	0.0	Alt 2	-12.0	Alt 0	-21.4	Alt 3	-32.0	Alt 1	-112.9
11	Credible	29,500	SRMC	9%	Med	100%	Alt 5	0.0	Alt 2	-22.4	Alt 0	-34.1	Alt 3	-49.6	Alt 1	-122.7
12	Sensitivity	29,500	SRMC	7%	Med	100%	Alt 5	0.0	Alt 2	-37.5	Alt 0	-51.5	Alt 3	-74.6	Alt 1	-137.2
12A	Credible	29,500	LRMC	9%	Med	110%	Alt 0	51.2	Alt 2	47.5	Alt 3	18.8	Alt 5	0.0	Alt 1	-62.8
12B	Credible	29,500	LRMC	9%	Med	90%	Alt 2	63.5	Alt 0	36.4	Alt 3	30.2	Alt 5	0.0	Alt 1	-26.8
13	Sensitivity	10,000	LRMC	11%	High	100%	Alt 3	108.7	Alt 2	101.4	Alt 0	92.0	Alt 1	0.5	Alt 5	0.0
14	Sensitivity	10,000	LRMC	11%	Med	100%	Alt 2	35.9	Alt 3	32.1	Alt 0	26.5	Alt 5	0.0	Alt 1	-65.0
15	Sensitivity	10,000	LRMC	11%	Low	100%	Alt 3	17.7	Alt 2	7.7	Alt 5	0.0	Alt 0	-1.7	Alt 1	-93.2
16	Sensitivity	10,000	LRMC	9%	High	100%	Alt 2	110.1	Alt 3	100.8	Alt 0	98.4	Alt 1	9.8	Alt 5	0.0
17	Sensitivity	10,000	LRMC	9%	Med	100%	Alt 2	28.3	Alt 3	21.1	Alt 0	16.6	Alt 5	0.0	Alt 1	-72.0
18	Sensitivity	10,000	LRMC	9%	Low	100%	Alt 3	4.3	Alt 5	0.0	Alt 2	-9.2	Alt 0	-20.9	Alt 1	-109.5
19	Sensitivity	10,000	LRMC	7%	High	100%	Alt 2	123.8	Alt 0	109.8	Alt 3	87.0	Alt 1	24.1	Alt 5	0.0
20	Sensitivity	10,000	LRMC	7%	Med	100%	Alt 2	11.5	Alt 3	0.5	Alt 5	0.0	Alt 0	-2.5	Alt 1	-88.2
21	Sensitivity	10,000	LRMC	7%	Low	100%	Alt 5	0.0	Alt 3	-22.3	Alt 2	-42.3	Alt 0	-56.3	Alt 1	-142.0
22	Sensitivity	10,000	SRMC	11%	Med	100%	Alt 5	0.0	Alt 2	-31.3	Alt 3	-37.7	Alt 0	-40.7	Alt 1	-132.2
23	Sensitivity	10,000	SRMC	9%	Med	100%	Alt 5	0.0	Alt 2	-49.2	Alt 3	-59.6	Alt 0	-60.9	Alt 1	-149.5
24	Sensitivity	10,000	SRMC	7%	Med	100%	Alt 5	0.0	Alt 2	-76.7	Alt 0	-90.7	Alt 3	-91.5	Alt 1	-176.4

Source: BRW Report, TEUS Supplementary Report & The Allen Consulting Group. Note: 'RNB' means net market benefits relative to Alternative 5.

Chapter 5

Capital Financing and Taxation

5.1 Code requirement for return on capital

The National Electricity Code requires the Commission to determine a revenue cap for the provision of a prescribed service that allows for a reasonable rate of return.

Clause 6.2.2(b)(2) of the Code requires that the transmission revenue regulatory regime administered by the Commission seek must to achieve, among other things:

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

Further guidance is provided in Clause 6.2.4(c)(4) of the Code, which states that, in setting each separate revenue cap, the Commission must have regard to:

> the weighted average cost of capital of the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) applicable to the relevant network service, having regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to those faced by the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) in the provision of that network service.

5.2 Methodology for determining the return on capital

(a) Post-tax nominal vanilla WACC

The Commission's approach to determining rates of return in recent decisions has been to calculate and apply what has become known as the vanilla form of the post-tax nominal WACC.[43] The term 'vanilla' refers to the fact that the WACC excludes tax affects, and so matters such as the value of imputation tax (franking) credits and the tax impact of interest expense are dealt with separately in the cash flows.

Mathematically, the post-tax vanilla WACC is represented as:

$$WACC = r_e \frac{E}{V} + r_d \frac{D}{V}$$

where:

43 Examples include the Commission's recent transmission revenue cap decisions for Transend (2003), Murraylink Transmission Company (2003), SPI PowerNet (2002) and ElectraNet SA (2002).

r_e is the post-tax nominal return on equity;

r_d is the nominal return on debt;

$\frac{D}{V}$ is the debt to value ratio; and

$\frac{E}{V}$ is the equity to value ratio.

While the Directlink Joint Venturers have followed the Commission's standard practice and adopted a WACC that is defined in *nominal* terms, they seek the Commission's assurance that both the revenue cap for the first regulatory period and the roll-forward of its regulatory asset base at the subsequent price review will be adjusted to reflect the difference between forecast and actual inflation. That is, the Directlink Joint Venturers seek confirmation that, notwithstanding the use of a nominal WACC, the revenue caps and regulatory asset base roll-forward will be undertaken in a manner that protects it against inflation risk, effectively providing a real rather than nominal return.

The protection against inflation risk is an essential component of CPI-X regulation as commonly understood, which is mandated as the form of regulation for transmission revenues through clause 6.2.4(a) of the Code. The Directlink Joint Venturers note that, if the regulatory regime were not to offer protection against inflation risk, then it would face substantially higher risk, and require a commensurately higher return.

(b) Methodology used to estimate the WACC

The estimation of the WACC for Directlink requires an estimate of the cost of equity associated with the project, and estimate of the cost of debt, and an assumption about the share of equity and debt in the financing of the asset.

This Application uses the Commission's standard approach of applying the simple form of the CAPM to guide the estimation of the cost of equity. The CAPM defines the return on equity as the sum of the return available on a risk free asset and the premium required by an investor to accept the risk associated with the specific asset. That is:

$$r_e = r_f + ß_e (r_m – r_f)$$

where:

r_e is the post-tax nominal return on equity

r_f is the nominal risk free rate

$(r_m - r_f)$ is the market risk premium

$ß_e$ is the equity beta

Of the CAPM parameters, only the equity beta is specific to any particular asset—all other inputs are economy-wide factors that affect the required rate of return on all assets. By definition a well-diversified portfolio of assets will have a beta of one, while more risky assets will have a beta greater than one, and less risky assets have a beta of less than one. However, as gearing levels affect the systematic risk borne by the equity providers, care must be taken with comparing equity betas with the market average—this issue is addressed further below.

The Application has also adopted the Commission's standard approach of adopting a benchmark for the cost of debt, rather than the actual debt costs of the project, as well as a benchmark assumption about the share of debt in the financing of the asset, reflecting the Code's emphasis on incentive regulation.[44] The cost of debt has been derived with reference to the prevailing cost of debt finance in the debt markets. The average of the estimated cost of equity and the observed cost of debt (weighted by the respective shares of equity and debt in the financing of the asset) can then be used as an estimate of the WACC for the asset.

The section 5.3 provides estimates of the relevant WACC parameters including:

- The risk free rate of return and the inflation forecast;
- The market risk (equity) premium;
- The beta associated with the proposed regulated activities; and
- The assumed finance structure and debt premium.

In addition to calculating the cost of equity and the cost of debt, this Chapter 5 also discusses the use of benchmark assumptions for the estimation of dividend imputation credits (gamma) and the appropriate allowance for the transactions costs of debt and equity.

(c) Principles to Guide the Estimation of the WACC

It is important to note that, where observable market data is used for estimating parameters of the CAPM and WACC, consistency is required. That is, the mathematical logic underlying the CAPM requires a consistent application of observable market data in relation to timescales, levels of gearing and other relevant assumptions.

5.3 Estimate of vanilla WACC

(a) Risk free rate of return and inflation forecast

The Directlink Joint Venturers have applied the Commission's standard approach for deriving the nominal risk free rate of using a recent average of the yield on bonds that have a term to maturity that matches the length of the regulatory period. As the

[44] Clause 6.2.4(a) of the Code.

Directlink Joint Venturers have proposed a 10 year regulatory control period (consistent with what the Commission accepted in the case of Murraylink Transmission Company), this has implied the use of 10 year bonds. The Directlink Joint Venturers have also adopted the Commission's standard approach of deriving its inflation forecast as the difference between the yield on nominal bonds and the yield on inflation-linked bonds of the same term, using the Fisher transformation.

For the purposes of this application, the latest practicable average of yields on Commonwealth Government nominal and inflation-linked bonds (days ending on 9 September 2004) was used, which provided the following nominal and real risk free rates and implied inflation forecast:

- 5.54 per cent nominal risk free rate;
- 2.94 per cent real risk free rate; and
- 2.53 per cent expected inflation.

The Directlink Joint Venturers have also followed the Commission's standard practice of using a linear interpolation of the yields on bonds with remaining terms that are the closest to 10 years to generate an estimate of the yield on bonds with a remaining term of exactly ten years.

While the Directlink Joint Venturers have proposed a risk free rate (and calculated its inflation forecast) with reference to bonds that have the same term as its proposed regulatory control period, it does not consider that it is appropriate to seek to align the term of bonds used to derive the risk free rate with the length of the regulatory control period. Rather, the Directlink Joint Venturers consider that its use of 10 year bonds would have been the correct approach irrespective of the length of the regulatory period.

The Directlink Joint Venturers consider that the bond term that is used to determine the risk free rate should reflect the term of the investment being considered, which, for transmission investments, are far longer that their regulatory control periods. The Australian Competition Tribunal ('**Tribunal**') has considered this matter in its decision on the *Application by GasNet Australia (Operations) Pty Ltd [2003] ACompt 6 (23 December 2003)*, and decided against the ACCC's standard approach. Specifically the Tribunal agreed with GasNet's proposition that the proper application of the CAPM requires the bond maturity to be matched to the life of the assets, or alternatively that the yield on longest traded bond be used:

> Specifically, GasNet contends that … [t]he conventional view of economists as a matter of theory and practical application is that the term of the bond should follow the life of the assets. This meant that in the absence of a well established market for longer-dated bonds in Australia, the appropriate rate was the rate for ten year bonds because it better reflected the life of the GasNet assets estimated to be thirty to fifty years.[45]

[45] Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd [2003] ACompt 6 (23 December 2003)*, para. 35.

> …
>
> The Tribunal is satisfied that the use by GasNet of a ten year Commonwealth bond rate to determine the Rate of Return on equity under s.8.30 of the Code was the correct use of the CAPM and in accordance with the conventional use of a ten year bond rate by economists and regulators where the life of the assets and length of the investment approximated thirty years in the MRP calculation and the risk-free rate.[46]

This implies that, for long life assets such as electricity transmission networks, the proper application of the CAPM should include a risk free rate that is more appropriately estimated with reference to the 10 year Commonwealth Government bond rate.

The Tribunal also emphasised the obvious need for consistency between the derivation of the market risk premium—which itself embodies an assumption about the risk free rate—and the risk free rate that is then applied as a separate input in the CAPM. Specifically the Tribunal found that:

> While it is no doubt true that the CAPM permits some flexibility in the choice of the inputs required by the model, it nevertheless requires that one remain true to the mathematical logic underlying the CAPM formula. In the present case, that requires a consistent use of the value of r_f in both parts of the CAPM equation where it occurs …
>
> … In truth and reality, the use of different values for a risk free rate in working out the Rate of Return by the CAPM formula is neither true to the formula nor a conventional use of the CAPM.[47]

It is implicit in the Tribunal's findings that it considered that the Commission's use of a market risk premium of 6 per cent had been calculated with reference to 10 year bonds. Accordingly, it found that consistency required that 10 year bonds also be used as the basis for the risk free rate.

The use of the 10 year Commonwealth Government bond rate to measure the risk free rate is preferred by market practitioners, and is adopted by every other Australian energy network regulator as a proxy for the risk free rate. The Commission stands alone in its use of bonds with shorter maturity terms.

(b) Market risk premium

The Directlink Joint Venturers have used a market risk premium of 6 per cent to estimate the WACC for Directlink, which reflects the ACCC's standard practice in its transmission revenue decisions to date, and which it has recommended retaining in its *Draft Decision, Statement of Principles for the Regulation of Electricity Transmission Revenues* ('**SRP Draft Decision'**).[48]

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46 Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd [2003] ACompt 6 (23 December 2003)*, para. 48.

47 ibid., paras 46-7.

48 SRP Discussion Paper, p. 25.

However, the Directlink Joint Venturers consider that this value is at the low end of the feasible range. The Directlink Joint Venturers considers there to be no reliable basis for adopting a market risk premium below this figure, but rather consider that the most robust estimation methodology would suggest that the best estimate of the market risk premium sits well above this figure.

The majority of academic experts and industry practitioners agree that the use of the long term historical average of the actual returns to Australian equities in excess of the actual returns to bonds provides the most reliable estimates of the market risk premium, which is approximately 7 per cent. By way of example, Professor Stephen Gray commented as follows in his recent paper entitled *Issues in Cost of Capital Estimation*:[49]

> A number of alternative approaches have been suggested for estimating the market risk premium. These include the use of survey data and some simple economic models that are based on very strong simplifying assumptions. There are problems associated with all of these approaches: Some produce negative estimates of the market risk premium, some produce imprecise results, and some are not well grounded in theory.
>
> In my view, there is no firm basis for moving from primary reliance on historical data to estimate the market risk premium.

Mehra and Prescott—two of the worlds most eminent finance academics—have recently expressed a similar view:[50]

> The data used to document the equity premium over the past 100 years is as good an economic data set as we have and this is a long series when it comes to economic data. Before we dismiss the premium , not only do we need to understand the observed phenomena but we also need a plausible explanation as to why the future is likely to be any different to the past. In the absence of this, and based on what we currently know, we can make the following claim: over the long horizon, the equity premium is likely to be similar to what it has been in the past and returns to investment in equity will continue to substantially dominate that in T-bills for investors with a long investment horizon.

The significance of Mehra Prescott's views is that they were the 'finders' of what has become known as the 'equity premium puzzle',[51] which is the inability of standard economic theory to explain the realised premium to equities over bonds. Clearly, the authors are more comfortable with placing weight on the actual market data, rather than on even their own theoretical model.

In recent years, a number of arguments have been raised by regulators that could have implied that the current market risk premium has fallen. These arguments include that the cost of diversification has become cheaper, as has trading in shares

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49 Gray, S., 'Issues in Cost of Capital Estimation', which Allgas submitted to the Productivity Commission in its submission, *Supplementary Submission to the Productivity Commission Review of the Gas Access Regime*, November 2003, pp. 5, 6.

50 Mehra, R. and Prescott E. 2003, 'The Equity Premium in Retrospect', in Constantinides, G., Harris M. and Stulz, R. (eds), *Handbook of the Economics of Finance*, vol. 1B, ch. 14, p. 928.

51 Mehra, R. and Prescott, E. 1985, 'The Equity Premium: A Puzzle', *Journal of Monetary Economy*, vol. 22, pp. 145-61.

generally, and that the structure of the market is now different to what it was at the start of the data set (although this could imply that the current premium is higher than implied by the long term historical average).[52] It has also been suggested that the more recent information on actual share market returns suggests that the premium has fallen. Table 5.1 shows the market risk premium calculated from actual share market returns for the longest period of observations available, as well as the premium that would be calculated from shorter time periods.

Table 5.1

HISTORICAL AUSTRALIAN MARKET RISK PREMIUM—1882 TO 2001

Time Period	Average Equity Risk Premium	Standard Deviation	Standard Error of the Mean
1882-2001	7.19%	16.97%	1.55%
Different Ending Point:			
1882-1950	8.00%	11.11%	1.34%
1882-1970	8.16%	13.70%	1.45%
1882-1990	7.40%	17.33%	1.66%
Different Beginning Point:			
1900-2001	7.14%	17.94%	1.78%
1950-2001	6.51%	22.60%	3.13%
1970-2001	3.37%	24.38%	4.31%

Source: Information in the first three columns produced by Professor Officer. Original information published in Officer, R., 'Rates of Return to shares, bond yields and inflation rates: An historical perspective', in *Share Markets and Portfolio Theory; Readings and Australian Evidence*, 2nd edition, University of Queensland Press, 1992.

As shown in Table 5.1, the market risk premium calculated from the longest period of observations was around 7.2 per cent, or 7.3 per cent if the non-cash value of franking credits for the period since 1987 are included. The table does show that the point estimate of the premium that is calculated from more recent data is lower—about 6.5 per cent (excluding the value of franking credits) for the post war period, and about 3.4 per cent (excluding the value of franking credits) for the period from 1970.

However, these figures also show why the average of returns over the longest period should be used. The standard deviation of the annual equity premium over the whole period is about 17 per cent—so, clearly, a large number of observations is required to make any sensible conclusion about the average premium. As an illustration, while the average premium over the period since 1970 may be 3.4 per cent, its standard error is 4.3 per cent—so that the 95 per cent confidence interval for the estimated premium is

[52] Indeed, the table below shows that the standard deviation in the annual equity premium *more than doubled* from 11.1 per cent for the period to 1950, to 22.6 per cent for the period after 1950. This suggests that, rather than becoming less risky, Australian equities have become much more risky—and so should demand a commensurately higher return.

approximately 3.4 per cent ± 8.6 per cent (excluding the value of franking credits). Put simply, the statistical uncertainty of estimates of the premium over such a short time period is so great as to make the average premium over the period since 1970 essentially meaningless.

Indeed, Professor Gray recently has undertaken statistical tests of whether actual returns provide any evidence of a change—or structural break—in the market risk premium since 1970, or at any other point since 1960. These tests statistically reject the hypothesis that the premium has changed, or that it differs to the long term average of 7 per cent. Professor Gray comments in the results as follows:[53]

> Given the difference in means and the variances of each sample, it is wrong to conclude that the market risk premium has fallen since 1970. To draw conclusions based on data with a demonstrable lack of statistical significance is to (i) reject the whole framework of statistical inference, (ii) ignore many years of standard practice, and (iii) introduce an element of arbitrariness into the regulatory procedure.

Notwithstanding the absence of any robust statistical evidence to support the view that the market risk premium may have fallen from that experienced in the past, a number of alternative methodologies for estimating the premium have been promoted in recent years. Chief amongst these are *ex ante* models based upon applying the dividend growth model to the market as a whole, and the use of survey evidence.

However, neither of these approaches provides sufficiently reliable evidence to justify the rejection of the historical premium. As Professor Gray has shown, the application of the *ex ante* models are likely to suffer from more statistical uncertainty than the use of historical averages.[54] The 'evidence' provided by surveys is even less convincing. All surveys suffer from the dual problems that the respondents are likely to respond in a manner consistent with their incentives, and the fact that a survey is not an estimate of what investors require—just an estimate of what particular market participants with their own interests report what investors require. Moreover, as Professor Gray has pointed out, the commonly referred to Australian survey—the 2000 Jardine Fleming Capital Partners survey—suffered from a number of flaws,[55] including a low response rate, ambiguity in the questions, as well as a high degree of dispersion in responses.

In summary, while the Directlink Joint Venturers have adopted a market risk premium in line with the ACCC's standard practice, it considers that this value is below the value provided by the most robust estimation methodology—the long term historical average—which implies a premium of approximately 7 per cent. In particular, any view that the premium is below the ACCC standard practice of 6 per cent is merely conjecture and is not based upon any robust market evidence, and should not be accorded any weight.

[53] Gray, S., *Issues in Cost of Capital Estimation*, which Allgas submitted to the Productivity Commission in its submission *Supplementary Submission to the Productivity Commission Review of the Gas Access Regime*, November 2003, p. 19.

[54] ibid., p. 23.

[55] ibid., p. 26.

(c) Equity Beta

This Application uses an equity beta of 1.13 to estimate the cost of capital associated with Directlink, reflecting an asset beta of 0.45 and a debt beta of zero.

The Commission has adopted an equity beta of 1 when estimating the cost of capital in its recent revenue cap decisions for transmission entities, and it has recently expressed the view that an equity beta of 1 is appropriate.[56] However, the Commission's view about the appropriateness of its standard equity beta of 1 rests on an exclusive reliance on beta estimates for the small number of listed Australian utility firms. The recent estimates of betas for the Australian listed firms have been highly erratic, giving little confidence in the robustness of the estimates. In addition, as NECG has pointed out, the estimates for the Australian firms also have poor statistical properties. None of the beta estimates for the Australian firms would pass conventional test of statistical significance, and the regressions from which the beta estimates are drawn explain virtually none of the returns of those firms.[57] Given these substantial problems, it is inappropriate to place any weight on these beta estimates when estimating the cost of capital for Directlink.

Rather, given the problems with betas for Australian-listed firms, there to be no option but to place weight on the betas for firms listed overseas. The Directlink Joint Venturers agree with the comments offered to the Commission by Professor Davis on this matter.[58]

> In practice, this is often not feasible, and betas are calculated for comparator firms operating in other countries and using the market portfolio of that country. It is then assumed that the systematic risk characteristics observed in that country are similar to those which would apply here. Although this approach, and assumptions involved, can be debated, there is no obvious preferable alternative, unless there is a significant portfolio of comparator stocks trading in the local market.

For the purpose of this Application, the Directlink Joint Venturers have relied upon the estimates of betas that the Network Economics Consulting Group ('**NECG**') has undertaken in the context of the Commission's current review of its Draft Regulatory Principles.[59] As NECG pointed out, its estimates have a number of attributes that would be expected to result in more reliable estimates of the beta associated with transmission activities.

- First, it has obtained beta estimates for 27 companies, 7 of which were explicitly electricity transmission entities, while the remainder have transmission activities, integrated with other activities. This compares to the Australian listed

[56] SRP Discussion Paper, p. 25.

[57] Network Economics Consulting Group 2003, 2*003 Review of Draft Statement of Principles for the Regulation of Transmission Revenues*, Submission to the ACCC for the electricity TNSPs from Network Economics Consulting Group, Sydney, pp. 51-2.

[58] Davis, K. 2003, *Report on Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, August, Melbourne, p. 19.

[59] Network Economics Consulting Group 2003, 2*003 Review of Draft Statement of Principles for the Regulation of Transmission Revenues*, Submission to the ACCC for the electricity TNSPs from Network Economics Consulting Group, Sydney, pp. 53-6.

firms that the ACCC typically includes in its sample of comparable entities (core sample of 5 and an extended sample of 9),[60] none of which are explicitly electricity transmission entities.

- Secondly, it has limited the sample only to the beta estimates that have a t-statistic of 2 or above. As NECG note, a t-statistic of 2 is typically taken as an indicator of the minimum level of statistical precision required in order to justify drawing inferences from the relevant estimate.

The full results presented by NECG are reproduced in Table 5.2 below. The last column has been added, which shows the re-levered equity beta that is consistent with the Directlink Joint Venturers' assumed gearing level of 60 per cent debt-to-assets.

Table 5.2

BETA ESTIMATES OF INTERNATIONAL BUSINESSES PRIMARILY INVOLVED IN ELECTRICITY TRANSMISSION—NOVEMBER 2003 (DEBT BETA = 0)

Country	Company	Raw equity beta	T-Stat	D/E ratio	Unadjusted asset beta (βd=0)	Relevered equity beta (βd=0)
Predominately Transmission-only entities						
Malaysia	Tenaga Nasional Berhad	1.31	11.91	96%	0.67	1.67
Pakistan	Karachi Electric Supply Corp	1.50	10.71	73%	0.87	2.17
Brazil	CTEEP	1.09	7.27	16%	0.94	2.35
Argentina	Transener S.A	0.60	4.62	376%	0.13	0.32
Spain	Red Electrica de Espana	0.68	2.62	144%	0.28	0.70
UK	National Grid Transco PLC	0.44	2.59	122%	0.20	0.50
Colombia	Interconexion Electrica S.A	0.26	2.36	223%	0.08	0.20
Integrated electricity businesses						
Turkey	Aksu Enerji ve Ticaret A.S.	0.80	16.00	0%	0.80	2.00
China	Guangxi Guigan Electric Power Co	1.03	12.88	3%	1.00	2.50
China	Sichuan Minjiang Hydropower Co	1.36	10.46	25%	1.09	2.72
China	Sichuan Mingxiang Electric Power Co	0.98	9.80	6%	0.92	2.31
Italy	Enel S.p.A.	0.54	9.00	43%	0.38	0.94
Portugal	EDP – Electricidade de Portugal	0.87	7.25	144%	0.36	0.89
Russia	RAO Unified Energy System	1.21	6.72	32%	0.92	2.29
Brazil	Companhia Energetica do Ceara	0.80	6.67	138%	0.34	0.84
India	Tata Power Company Limited	1.20	5.45	122%	0.54	1.35

[60] SRP Discussion Paper, p. 78.

Country	Company	Raw equity beta	T-Stat	D/E ratio	Unadjusted asset beta (βd=0)	Relevered equity beta (βd=0)
Spain	Hidroelectrica del Cantabrico	0.41	5.13	28%	0.32	0.80
Chile	Enersis S.A.	1.02	4.86	285%	0.27	0.66
Malaysia	Sarawak Enterprise Corp Berhad	1.02	4.43	27%	0.81	2.01
Brazil	Light Servicos de Electricidade S.A.	0.84	4.00	426%	0.16	0.40
Spain	Union Fenosa, S.A.	0.60	3.75	156%	0.23	0.59
Russia	Samaraenergo	1.24	3.65	33%	0.93	2.33
Russia	Sverdlovenergo	0.63	3.00	113%	0.30	0.74
US	PNM Resources Inc.	0.69	2.88	104%	0.34	0.85
Russia	Krasnoyarskenergo	1.66	2.86	12%	1.48	3.71
US	Cleco Corporation	0.55	2.62	138%	0.23	0.58
Chile	Edelnor S.A.	1.09	2.48	1150%	0.09	0.22
Average (transmission companies)		**0.84**	**0.89**	**150%**	**0.45**	**1.13**
Average (integrated)		**0.93**	**0.95**	**149%**	**0.57**	**1.44**
Average (all companies)		**0.90**	**0.94**	**149%**	**0.54**	**1.36**

Source: NECG 2003, *2003 Review of draft statement of principles for the regulation of transmission revenues*, Sydney p.55

According to the NECG results, the average asset beta for the transmission-only businesses is 0.45, with a 95 pr cent confidence limit of 0.27, whereas the average asset beta for the whole sample (that is, including the integrated firms) is 0.54, with a 95 per cent confidence interval of ±0.14. These translate into a re-levered equity beta (consistent with a 60 per cent level of gearing and using NECG's assumed debt beta of zero) of 1.13 and 1.44 respectively.

The choice between these two beta estimates is essentially a trade-off between precision and bias—that is, while the beta estimate derived from the sample including all firms has a lower standard error, there is a chance that the inclusion of non-transmission activities may have affected the beta estimate. Accordingly, the Directlink Joint Venturers have adopted a conservative approach, and used the re-levered equity beta derived from the smaller sample of transmission-only firms of 1.13 for the purposes of estimating Directlink's cost of capital.

Lastly, the Commission has justified its view that its standard practice equity beta of 1 is conservative by drawing comparisons with the market as a whole. Its recent statement on this issue was as follows.[61]

[61] SRP Discussion Paper, p. 76.

> A βe of less than one intuitively seems more appropriate for regulated electricity networks in Australia given the level of market risk which they face. These firms are regulated entities guaranteed a revenue stream and the demand for its essential services is inelastic. Providing an βe of one implies that the regulated companies face the same variability of returns to equity as the market portfolio. Given this, it seems inappropriate to allow an βe of one for these regulated firms when they are insulated from many of the risks faced by the rest of the market.

This observation by the Commission is seriously misled as it takes no account of the difference in the average level of gearing of the equities listed on the Australian share market and the level of gearing assumed when estimating the cost of capital for transmission providers. That is, in order to make an accurate comparison of the degree of risk assumed for transmission activities as against the average risk of the activities of Australian share market listed entities, it is essential to adjust for the difference in the gearing assumed for transmission and that of the market as a whole.

Such an adjustment was undertaken by the Victorian Office of the Regulator-General ('**ORG**', now the Essential Services Commission of Victoria) in its 1998 gas access arrangements review.[62] The ORG's 1998 analysis found that:

- the average level of gearing employed by a sample of 47 of Australia's top 100 listed companies was around 33 per cent debt to total assets; which implied that

- the asset beta for the 'market' was around 0.7; and

- the average equity beta of geared to 60 per cent debt to total assets was around 1.6.

Thus, it follows that transmission activities only have:

- 64 per cent of the risk of the average listed entity comparing asset betas (that is, 0.45 compared to 0.7), or

- 70 per cent of the risk comparing equity betas (that is, 1.125 compared to 1.6).

In any case, it is clear that the equity beta assumed by the Directlink Joint Venturers implies a far lower level of risk than the market as a whole, as the Commission's intuition would indicate.

(d) Cost of debt and financing assumptions

Consistent with the Commission's standard practice, the Directlink Joint Venturers have adopted a gearing level (debt to equity) of 60 per cent for the purpose of establishing a WACC for Directlink. The Directlink Joint Venturers also propose a debt margin of 1.50 per cent. This has been estimated from the indicative yield on Australian corporate bonds with a BBB+ benchmark credit rating.

[62] Office of the Regulator-General, Victoria, *Staff Paper Number 1: Weighted Average Cost of Capital for Revenue Determination - Gas Distribution*, 28 May 1998.

In Australia, an assumed gearing level of 60 per cent has emerged as the industry norm for regulated network businesses. The adoption of a benchmark gearing level of 60 per cent is appropriate, provided that the margin on the cost of debt is derived to be consistent with this gearing level.

The Commission's current approach to deriving a benchmark cost of debt is to make an assumption about the credit rating that a transmission owner could maintain if it were geared to the benchmark level. In turn, the Commission has observed the credit ratings of Australian electricity utilities, and formed the view that an A credit rating is reasonable.

However, in forming its views about the credit rating that a transmission entity with the benchmark level of gearing could maintain, the Commission has had a regard to a sample of firms that includes both privately-owned and government-owned enterprises. The Commission has justified the inclusion on the basis that the inclusion of only the privately-owned entities would provide a too small a sample of firms. This was noted by the Commission in its SRP Discussion Paper.[63]

> In its sample of determining the average credit rating for the electricity industry, the Commission has included both private and government backed entities. By simply using stand-alone and private entities, it would provide too small a sample to obtain an average credit rating for the electricity industry.

However, the Commission's current approach of including government-owned entities in the sample in inappropriate, and appears to have led to the Commission overstating the credit rating that a transmission entity with the benchmark level of gearing could maintain.

One concern with the inclusion of government-owned entities is that the existence of an implicit government guarantee may bias upward the credit rating—even if an attempt is made to determine the credit rating on a stand alone basis. As NECG has commented, a failure to account for the effect of government-ownership on matters like credit ratings would violate all principles of competitive neutrality for government-owned firms,[64] and systematically under-compensate privately owned firms.

A second—and more fundamental—concern is that it is impossible to make sensible inferences from the recorded gearing levels of the government-owned firms. The relevant measure of gearing in finance generally is the ratio of the *market value* of debt to the market value of the asset. While the book value of debt is typically taken as a close proxy for its market value, accounting values for equity are very poor proxies for their market value. For privately owned firms that are listed on the share market, the market value of the firm can be observed directly from share price data. Moreover, the book values of recently privatised firms would be expected to have been reset in line with the acquisition price—and hence provide a reasonable proxy for market value. In

[63] SRP Discussion Paper, p. 83.

[64] Network Economics Consulting Group 2003, 2*003 Review of Draft Statement of Principles for the Regulation of Transmission Revenues*, Submission to the ACCC for the electricity TNSPs from Network Economics Consulting Group, Sydney, p.58

contrast, the only proxy for the market value of government-owned firms that is available is the book values, which do not reflect prevailing market values, unlike the market value calculated from share price data, and would not have been reset to reflect a recent acquisition price, unlike recently privatised utilities.

Given an insufficient sample of comparable privately-owned electricity businesses, the more appropriate response would be for the Commission to include the privately-owned gas utility businesses in its sample. This would be consistent with the Commission's approach to estimating the equity beta. Furthermore, the inclusion in the sample of privately-owned gas utility businesses would not upwardly bias the average credit rating of the sample, nor would it violate the principles of competitive neutrality.

The gearing levels and credit ratings for the major Australian privately-owned energy utility businesses are set out in Table 5.3.

Table 5.3

GEARING LEVELS AND CREDIT RATINGS FOR AUSTRALIAN UTILITIES

Entity	Credit Rating	Gearing Date	Gearing (D/A)	Measure of Gearing
Envestra	BBB	Jun 2003	69.0%	Market value
GasNet	BBB	Jun 2003	63.2%	Market value
ETSA Utilities	A-	Dec 2002	63.5%	Book value
CitiPower Trust	A-	Dec 2002	20.6%	Book value
Powercor	A-	Dec 2002	39.7%	Book value
ElectraNet	BBB+	Dec 2002	72.6%	Book value
Australian Pipeline Trust	High BBB[65]	Jun 2003	50.7%	Market value
AlintaGas	BBB	Jun 2002	35.4%	Market value
United Energy	A-	Jun 2002	51.0%	Market value
TXU	BBB	Dec 2002	67.1%	Book value
SPI PowerNet	A+	Mar 2003	79.8%	Book value

Source: 'Book value' gearing levels taken from: Standard and Poor's (2003), *Australian Report Card: Utilities*, p. 5. 'Market value' gearing levels were derived from share price data (sourced from the ASX) and debt values were taken from company annual reports or ASX filings.
A historical rating and gearing level was used for United Energy and AlintaGas to avoid any noise associated with AlintaGas' recent purchase of United Energy. The credit ratings were taken from: Standard and Poor's (2002), *Project and Infrastructure Finance Review*, October.

[65] The Australian Pipeline Trust does not have a formal credit rating. However, the company recently announced that, in a recent private placement. it had 'successfully positioned [itself] as a high BBB issuer': Australian Pipeline Trust, Media Release, 10 September 2003.

As the last column indicates, the gearing levels for 5 of the eleven businesses in the sample have been calculated from share price information, and so reflect the market value of the equity component of the asset. In addition, of the remaining businesses, all have been the subject of a sale (either initial privatisation or subsequent trade sale) in the last five years. Table 5.3 suggests that, while a number of factors go into determining a company's credit rating, this data suggests that adopting a credit rating of BBB+ for a utility company with benchmark gearing of 60 per cent would be most consistent with market observations.

Regarding the source that is used to derive the debt margin that is consistent with the benchmark BBB+ credit rating and term consistent with the risk free rate, it is noted that the Commission's standard practice has been to use a short term average of the debt margins provided by the CBASpectrum service. The Directlink Joint Venturers have significant concerns with the use of a *short term average* of the margins provided by the CBASpectrum service as the basis of the debt margin that is adopted for regulatory purposes.

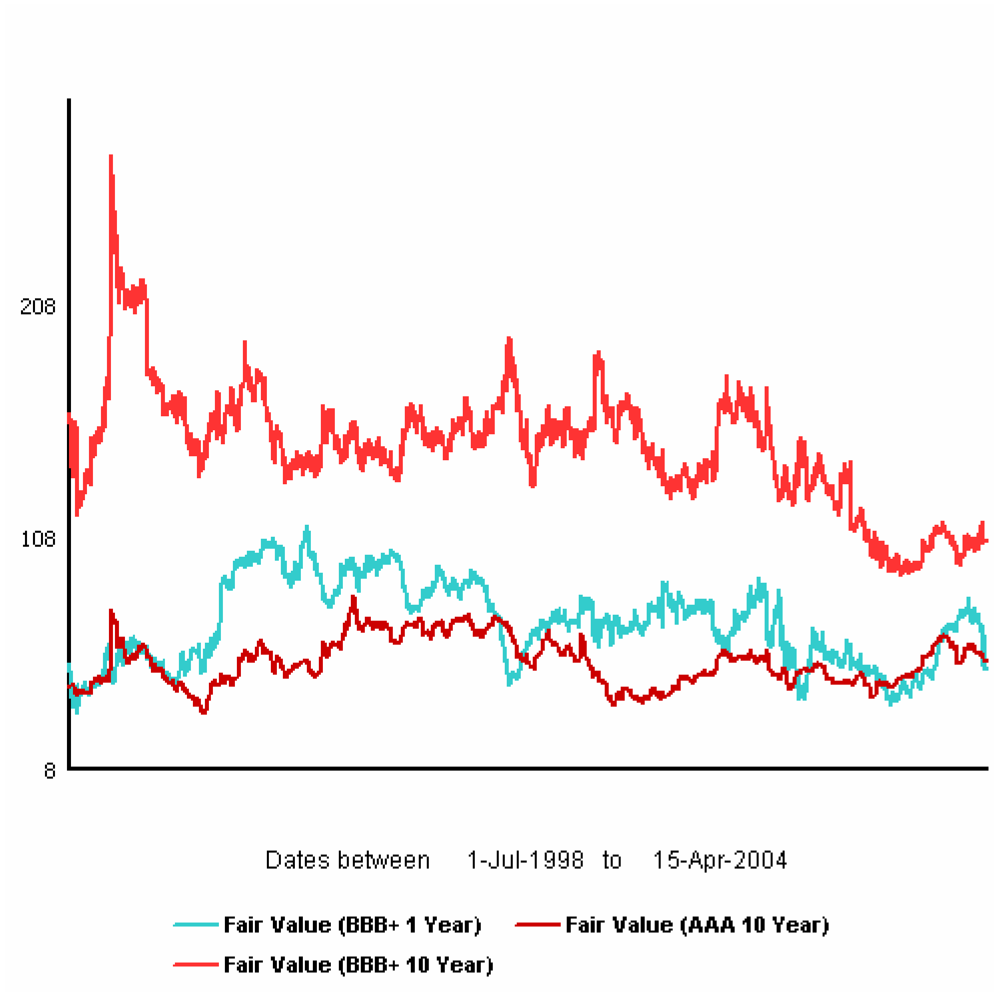
The output from the CBA Spectrum service that has been used by the Commission in previous matters is the indicator that is provided for the yield on corporate bonds across the range of terms from 1 to 10 years and credit ratings from BBB to AAA. However, it is important to understand that the indicator rates are not actual market observations, but a prediction of the yields based upon the available evidence and an econometric model. For the categories of bonds with many on issue—short term, highly-rated issuers—the predicted yields would be expected to provide an accurate proxy for current market rates. However, where there are few bonds on issue, then the predicted yields would be expected to be associated with a high degree of statistical imprecision. Less than 3 per cent of corporate bonds have a credit rating of less than an A rating, and as at 16 April 2004,[66] the CBA Spectrum database only contained three corporate bonds with a BBB+ rating, only one of which had a term in excess of 4 years.[67]

Figure 5.1 shows the volatility in the CBASpectrum predicted yields over the period covered by the service (1 July 1998). It is clear from the figure that the predicted margins for BBB+ / 10 year bonds have been highly variable, even over very short periods of time. By way of example, in late 1998, margins rose from about 150 basis points to over 270, only to revert to their previous levels within a matter of months—while the margins on higher rated bonds moved to a much less significant extent, and the margin on short-term BBB+ bonds barely moved at all. Moreover, less significant—but still substantial—changes in the predicted margin are repeated over the series. It is also clear from this figure that the current predicted margins represent a historical low in the predicted yields for this class of debt.

[66] *The Australian Financial Review*, 2 February 2004.
[67] Sourced from **http://cbaspectrum.com.au** on 16 April 2004.

Figure 5.1

CBA SPECTRUM PREDICTED DEBT MARGINS



Source: CBASpectrum.com.au, accessed 16 April 2004.

The thinness in the sample of long-date, low-rated corporate bonds implies that much of the variation in the predicted yields most likely reflects statistical error in the estimation procedure, rather than a true reflection of changes in the market cost of debt. Given this high degree of statistical error present in the predicted yields, it may be questioned whether it is appropriate to place reliance on these predicted yields for regulatory purposes. However, to the extent that reliance is placed upon the CBA Spectrum indicator yields, the extreme volatility in the predicted yields implies that the use of a short term average clearly is inappropriate. Rather, as the statistical errors in the predicted yield would tend to cancel out over time, a more precise estimate of the debt margin would be derived by taking a long term average of the debt margin that is predicted by the CBA Spectrum service.

For the purpose of this application, the long term average of the CBA Spectrum predicted debt margin that was used by the Essential Services Commission of South Australia (‘**ESCOSA**’) in a recent paper has been adopted,[68] which is 1.5 per cent (excluding the transaction cost of debt). Indeed, the ESCOSA paper provides a precedent for the use the long term average of the CBA Spectrum predicted yield rather than the use of a short term average.

(e) Summary of cost of capital and WACC estimates

Table 5.4 summarises the estimates for each of the parameters required for calculating a WACC for the Directlink Joint Venturers. Based on these estimated parameters, the Directlink Joint Ventures propose a nominal vanilla WACC of 9.29 per cent.

Table 5.4
COSTS OF CAPITAL ESTIMATES

Parameter	Value
Nominal risk free rate	5.54%
Real risk free rate	2.94%
Implied inflation factor	2.53%
Equity beta	1.13
Market risk premium	6.00%
Debt margin	1.50%
Gearing (debt/assets)	60%
Corporate tax rate	0.3
Value of franking credits (Gamma)	0.5
Post-tax cost of equity (nominal)	12.32%
Post-tax cost of equity (real)	9.55%
Cost of debt (nominal)	7.04%
Cost of debt (real)	4.40%
Nominal vanilla cost of capital	9.16%
Real vanilla cost of capital	6.46%

[68] ESCOSA, *Electricity Distribution Price Review: Return on Assets – Preliminary Views*, January 2004, p.71.

5.4 Value of imputation (franking) credits – gamma

The CAPM and WACC equations described above provide an estimate of the cost of capital in post (company) tax terms. Given that the Directlink Joint Venturers are liable for Australian company tax, a revenue allowance for the expected company tax expense is required. The derivation of an allowance for taxation requires an assumption about the value of franking credits, which is often referred to as the 'gamma'.

The Directlink Joint Venturers consider that the feasible range for gamma is probably between 0.3 and 0.5, although strong arguments that the value is closer to zero can be made. However, for the purposes of this Application, the Directlink Joint Venturers have adopted a conservative approach: a value for gamma at the top of this feasible range of 0.50.

As noted in the Commission's recent discussion paper on its Draft Regulatory Principles, there is a great deal of uncertainty regarding the appropriate value of gamma.[69] In particular, not only has there been debate about the size of gamma from empirical estimates, there has been debate about what theory would predict for the value of imputation credits.

Turning first to the empirical estimates, the estimates of the value of franking credits in the studies that regulators typically have had regard to are set out in Table 5.5.

Table 5.5

EMPIRICAL ESTIMATES OF THE VALUE OF IMPUTATION CREDITS

Study	Methodology	Estimated value of gamma
Brown & Clarke (1993)	Inference from dividend drop-offs	72%
Bruckner, Dews & White (1994)	Inference from dividend drop-offs	33.5% – 68.5%
Hathaway & Officer (1999)	Analysis of tax statistics	48%
	Inference from Dividend drop-offs	49% (large companies)
		44% (all companies)
Walker & Partington (1999)	Simultaneous trading of ex-div and cum-div shares	88% or 96%
Chu & Partington (2001)	Inference from trading around rights issues	Close to 100%
Twite & Wood (2002)	Inference from trading in individual share futures	45%
Cannavan, Finn & Gray (2003)	Inference from value of individual share futures and low exercise price options	0%

Source: Brown, P. and Clarke, A. 1993, 'The Ex-Dividend day behaviour of Australian share prices before and after dividend imputation', *Australian Journal of Management*, vol. 18, no. 1, pp. 1-40; Bruckner, K. N. Dews and White, D. 1994, *Capturing value from dividend imputation*, McKinsey & Company; Hathaway, N. and Officer, R.R. 1999, *The Value of Imputation Tax Credits*, Unpublished manuscript, Graduate School of Management, University of Melbourne;

[69] Draft Regulatory Principles, p.88.

Walker, S. and Partington, G. 1999, 'The Value of Dividends: Evidence from cum-dividend trading in the ex-dividend period', *Accounting and Finance*, vol. 39, p. 293; Chu, H. and Partington, G. 2001, *The market value of dividends: Theory and evidence from a new method*, working paper, University of Technology, Sydney, p. 39; Twite, G. and Wood, J. February 2002, *The pricing of Australian imputation tax credits; Evidence from individual share futures contracts*, working paper; Cannavan, D., Finn, F. and Gray, S., 2002, 'The value of imputation tax credits', *Journal of Financial Economics* (forthcoming).

It is clear from the results provided above that the empirical estimates of the value of franking credits cover a substantial range, from almost fully valued to not valued at all. In addition, in a recent paper, Professor Gray has assessed in detail many of the studies in the table above, and identified a number of shortcomings.[70]

- First, the standard errors in a number of the studies are so wide as to make the results virtually impossible to interpret. This is particularly the case for the Bruckner et al. and Chu et al. studies.

- Secondly, the results in the dividend drop-off studies—and particularly the Officer et al study—are even harder to interpret because of the problem of multi-colinearity. That is, the proportion of fully-franked dividends is so high that it is difficult to separate the value of franking credits from the value of the cash dividends using the dividend drop-off methodology. Gray shows that the Officer et al results are also consistent with the proposition that cash dividends are valued fully (consistent with the wealth of evidence from the US) and that franking credits are not value at all.

- Thirdly, a further problem with dividend drop-off studies is that the measurement of dividend prices around the time that dividends are declared is measured with error, and the movements in prices at that point in time may be dominated by short term arbitrageurs rather than the long term investors who set the cost of capital for the activity.

- Fourthly, many of the studies in the table above predate a number of changes to the taxation system that would be expected to have a substantial effect on the value of franking credits to foreigners. These changes include the introduction of anti-streaming provisions from 1 July 1990 (which prevented imputation credits from being channelled to domestic shareholders) and the introduction of the 45 day rule from 1 July 1997 (which substantially reduced the benefit from seeking to capture the value of franking credits by trading around the ex div date).

The one study in the above that gets around many of these problems is that by Cannavan et al, shortly to be published in one of the top international finance journals. The Cannavan et al methodology has a number of desirable features.

[70] Gray, S., 'Issues in Cost of Capital Estimation', which Allgas submitted to the Productivity Commission in its submission, *Supplementary Submission to the Productivity Commission Review of the Gas Access Regime*, November 2003, pp. 35-39.

- First, the technique permits a far larger sample of observations used—as there will be a new observation whenever there is a trade in the relevant derivative, rather than being restricted to two observations per firm per annum. This has permitted estimates to be obtained that have far greater precision (that is, lower standard errors).
- Secondly, as the derivatives trade well in advance of ex-dividend dates, there is less likelihood that the values estimated for franking credits will be affected by the actions of short term arbitrageurs around the ex-dividend date.
- Thirdly, the study has been able to use information that post-dates the changes to the tax law discussed above (and to test the impact of those changes to the tax law).

It is notable that the study that has the most robust estimation methodology and which takes account of the most recent information also suggests that the best estimate of the market value of franking credits is probably closer to zero than to the 0.5 that Australian regulators have adopted as standard. Professor Grundy has recently summarised the results of the Cannavan et al study as follows.[71]

> In a forthcoming publication, Cannavan, Finn and Gray (2003) [CFG] undertake a thorough empirical study of our fundamental question. They do so by examining data on individual share futures contracts.
>
> …
>
> In 1997 tax law changes that precluded the share trading strategies that had previously allowed non-resident investors to effectively enjoy the benefits of tax credits were introduced. From an examination of post 1997 share and futures prices, CFG conclude that 'it is difficult to detect any value in tax credits at all after the amendment.'
>
> Australian residents may well enjoy the tax credit, but post 1997 they have not had to pay any more for a dollar of franked dividends (i.e., dividends with attached tax credits) then they must pay for a dollar of unfranked dividends. The implication for Australian companies raising equity capital is clear. To raise capital Australian companies must price the issue so that it is potentially attractive to overseas investors; i.e., to investors who do not qualify for imputation credits. Thus the best available empirical evidence on the value of gamma under the current tax law is that gamma is zero.

The findings of the Cannavan et al study are also consistent with the notion that it is the marginal provider of capital in the market that sets the cost of capital, and that, given Australia's dependence on foreign capital, that investor is most likely to be a foreign-domiciled investor. It is relevant in this context that non-resident investors own around 37.5 per cent of the value of the Australian Stock Exchange.[72] Given the extent of foreign ownership in Australia, it is illogical to assume that foreign investors do not exert substantial influence on the prices of Australian financial assets.

[71] Grundy 2003, 'The value of gamma', which TransGrid submitted to the Commission in its 2003 submission, *TransGrid 2004 Revenue Reset Application*, pp. 3-4.

[72] Network Economics Consulting Group 2003, *Weighted Average Cost of Capital for Transend, submission to the ACCC by Network Economics Consulting Group*, Sydney, p. 47.

The Commission and several other regulators have countered the proposition that foreign-investors affect the cost of capital associated with the proposition that taking account of foreigner investors would cause bias, because the Commission is using a 'segmented markets' version of the CAPM (the '**segmented markets proposition**'). The logic of this proposition is as follows.

- The version of the CAPM we are using assumes segmented markets.
- All of the parameter inputs into the CAPM—such as the market risk premium—assume segmented markets. Consistency requires gamma to be estimated as if Australia were segmented.
- If an international version of the CAPM were used—which would be consistent with a zero gamma—it would deliver a lower cost of capital than the segmented markets CAPM because, amongst other things, the market risk premium would be lower.

As NERA has pointed out, however, the important assumption in the segmented markets proposition is that the current CAPM inputs have been derived on the assumption of segmented capital markets, and in particular, that 'integration' has implied a sudden and significant drop in the market risk premium. NERA demonstrated that, in the absence of 'integration' having a recent, substantial effect on required investor returns, that the application of the domestic CAPM would provide a good estimate of the result that would be obtained from one of the more complex international CAPM models.[73]

> The 'take home message' here is that adopting the international CAPM versus the domestic CAPM does not lead to any a priori bias in the estimated WACC provided that the equity beta and the MRP are both collected from the same market and historical data is a reasonable estimate of forward looking expectations.
>
> This is a very important point as it has been argued, including by Lally, that use of domestic data within a CAPM model will lead to a downward bias in the estimated WACC compared to the true (international CAPM) WACC. The above analysis shows that it is false to argue that such an a priori presumption can be made. However, the above finding does not mean that it is wrong to presume that integration of world equity markets will reduce the WACC required by Australian companies. Rather it shows that there is no reason to believe that use of historical domestic data in a CAPM model will result in a lower estimated WACC than use of historical international data in a CAPM model.
>
> Of course, if both international and domestic historical data is a biased downwards (say because a sudden change in the level of integration of world equity markets has lowered the MRP demanded by investors) then both an international and a domestic CAPM using historical data will overestimate the true WACC (other things constant). However, this is fundamentally an hypothesis that something of sufficient importance has happened sufficiently recently to render use of historical data in the CAPM (be it domestic or international) inappropriate. While this may be the case, it must be recognised that it is an assertion of, by definition, an untestable hypothesis.

[73] NERA 2003, 'International versus Domestic CAPM' in attachment 16 of TransGrid 2003, *TransGrid 2004 Revenue Reset Application*, Sydney p. 9.

NERA subsequently cast doubt on whether 'internationalisation' would have had such a sudden and significant impact on required investor returns in Australia as assumed by the 'segmented markets' critique, described above.[74]

> It is particularly unusual that the very strong assumptions that historical Australian market data is from a perfectly segregated market is made implicitly - without any discussion of the academic literature concerning the time period over which world capital markets have been integrated. It is NERA's view world capital markets have been significantly integrated for the last 100 years. Certainly, Australia has relied on the net importation of capital in almost every year during that period. While it may well be the case that the speed at which short term international arbitrage opportunities have become traded has dramatically increased since the development of cheaper computing and telecommunications in the 1960s and beyond, the idea that debt and equity markets prior to then were 'fully segregated' is itself a very strong assumption. Differentials in expected rates of return across international capital markets may have lasted longer in the earlier half of this century, however, the assumption that their existence did not attract any equilibrating capital flows is very strong. It is also inconsistent with the evidence on international capital flows over that period – with Australia relying heavily on foreign direct and indirect investment.

Accordingly, the Directlink Joint Venture considers that the most robust evidence available suggests that the value of franking credits is closer to zero than to the 'regulatory standard' assumption of 0.50. Moreover, it does not consider that the critique of the empirical estimates based upon the presence of foreigner investors being inconsistent with the version of CAPM employed itself to have any validity—relying as it does on fundamental propositions that are both untestable and inconsistent with intuition.

This Application has adopted a conservative approach to the selection of the gamma value and used the 'regulatory standard' value of 0.50. However, the Directlink Joint Venturers consider that the empirical evidence suggests that this is more likely than not to overstate the value of imputation credits, and that there is no sound basis for adopting a higher value.

5.5 Debt and equity issuance costs

The Commission's recent practice has been to recognise that raising—as well as servicing—finance are legitimate costs of providing regulated services, and has provided a benchmark allowance for the transactions costs associated with raising both debt and equity finance.[75] In relation to equity finance, the Commission has noted as follows:[76]

> As with debt raising costs, the Commission considers it is appropriate to provide a benchmark allowance for equity raising costs. Equity raising costs must be paid by an entity when it raises capital. These costs are paid to equity arrangers for services such

[74] ibid., p.16.

[75] Examples include the Commission's recent transmission revenue cap decisions for Transend (2003), Murraylink Transmission Company, (2003) SPI PowerNet (2002) and ElectraNet SA (2002).

[76] Australian Competition and Consumer Commission, *Decision: South Australian Transmission Network Revenue Cap 2003-2007/8*, 11 December 2002, p. 28.

as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors.

The Directlink Joint Venturers concur with the Commission's view that substantial costs are incurred in raising and re-raising both debt and equity finance, which should be reflected in the revenue caps for transmission network service providers.

The Commission's standard allowance for debt raising costs has depended upon the credit rating assumed when calculating the debt margin, providing an allowance of 0.125 per cent per annum on the regulatory value of debt for a BBB+ rating. However, the Australian Competition Tribunal recently held that an allowance of 0.25 per cent was more appropriate[77], so 0.25 per cent has been used in this Application.

The Commission's allowance for equity raising costs has varied marginally across its recent decisions, and was 0.212 per cent per annum on the regulatory value of equity in its most recent decision.[78] An allowance of 0.212 per cent has been used in this Application.

Consistent with the Commission's preferred approach, these allowances of 0.25 per cent per annum on the regulatory debt value and 0.212 per cent per annum on the regulatory equity value have been included in the forecast operating expenses for Directlink.

[77] Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd [2003] ACompt 6 (23 December 2003)*, paragraph 2a, p. 4.

[78] Australian Competition and Consumer Commission, *Decision: Tasmanian Transmission Network Revenue Cap 2004–2008/9*, 10 December 2003, pp. 27-8.

Chapter 6

Revenue determination

6.1 Regulatory control period

The Directlink Joint Venturers propose that a regulatory control period that commences from the date upon which the Commission's final decision on this Application comes into effect and expires on 31 December 2014.

This regulatory control period is justified given the high initial and ongoing efficiency of Directlink's operation and maintenance, the unlikelihood of unforeseen capital expenditure, and the substantial cost savings to the Commission, the NEM participants and the Directlink Joint Venturers associated with deferring the next regulatory review process until 2014.

In addition, a regulatory period of 10 years provides certainty that encourages private sector investment and attracts new entrants to the NEM. Transmission investments are very long term investments for which investors seek as much certainty as is reasonably possible, especially for regulated investments where returns are designed to reflect lower levels of risk. Upon appropriate conditions, such as those presented by Murraylink, the Commission's acceptance of an almost 10 year regulatory control period would provide a positive signal to investors that the Commission is willing to provide a good level of certainty where it can.

6.2 The critical alternative project

Given the analytical framework set down in section 1.4(c) and conclusions in section 4.7(g), Alternative 2 is the project that satisfies the Regulatory Test and, consequently, would determine the opening asset value for Directlink.

The relevant characteristics of this project are set out in Table 6.1.

Table 6.1

OPENING ASSET VALUE INPUTS TO DIRECTLINK REVENUE MODEL—ORC VALUES

	Directlink	
	ORC Value ($M)	ACCC Standard Asset Lives (yrs)
Substation costs	93.2	40
Transmission costs	60.0	50
Easement costs	0.0	∞
Total capital cost (incl. IDC)	153.2	

Values are in July 2005 dollars.

For the Murraylink decision, the Commission adopted its estimate of the full cost of the alternative project as the opening regulatory asset base, and depreciated the asset over the life of the new asset rather than the life of the actual asset in service. For the Murraylink asset, this simplified approach was justified, given that the Murraylink asset had only been in service for approximately 12 months at the time of conversion.

With the normal application of an optimised depreciated replacement cost (**'ODRC'**) valuation, whereby the optimised replacement cost (**'ORC'**) value is typically reduced (depreciated) according to the time it has been in service, and then the opening regulatory asset base is depreciated over the remaining life of the actual assets.

As Directlink would have been in service for about 5.0 years by the July 2005, the Directlink Joint Venturers have anticipated that the Commission would apply the normal ODRC approach, that is, to scale down the ORC to reflect Directlink's time in service. This stance is reflected in the revenue projections set out in Table 6.2 below.

Table 6.2

OPENING ASSET VALUE INPUTS TO DIRECTLINK REVENUE MODEL—ODRC VALUES

	Directlink	
	ODRC Value ($M)	Remaining Life (yrs)
Substation costs	81.5	35.0
Transmission costs	54.0	45.0
Easement costs	0.0	∞
Total capital cost (depreciated)	135.6	
Annual operating expenditure (real)	2.931-3.1387	

Values are in July 2005 dollars

6.3 Roll-forward asset value

Alternative 2 does not require any additional capital expenditure over the 10 years from July 2005. Subsequently, the capital expenditure cash flow and the resulting rolled-forward asset value is shown in Table 6.3 and Table 6.4 in nominal and real terms, respectively.

Table 6.3

DIRECTLINK'S ROLL-FORWARD ASSET VALUE (HISTORICAL COST, NOMINAL, $M)

Year commencing 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Opening asset value	135.6	135.4	135.1	134.7	134.2	133.6	132.8	132.0	131.0	129.9
Capital expenditure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return of capital	0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.2
Closing asset value	**135.4**	**135.1**	**134.7**	**134.2**	**133.6**	**132.8**	**132.0**	**131.0**	**129.9**	**128.7**

Values in nominal dollars.

Table 6.4

DIRECTLINK'S ROLL-FORWARD ASSET VALUE (CURRENT COST, REAL, $M)

Year commencing 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Opening asset value	135.6	132.0	128.5	125.0	121.4	117.9	114.4	110.8	107.3	103.8
Capital expenditure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return of capital	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53
Closing asset value	**132.0**	**128.5**	**125.0**	**121.4**	**117.9**	**114.4**	**110.8**	**107.3**	**103.8**	**100.3**

Values in July 2005 dollars.

6.4 Operating expenditure

The Directlink Joint Venturers' operating expenditure allowance will be made up of the expected O&M expenditure for Alternative 2, as estimated by BRW, plus an allowance for debt and equity issuance costs.

Debt issuance costs have been calculated as 0.25% of 60% of regualtory asset value per year, and, equity issuance costs have been calculated as 0.212% of 40% of regulatory asset value per year. Subsequently, the appropriate operating expenditure allowance is shown in Table 6.5.

Table 6.5

DIRECTLINK'S OPERATING EXPENDITURE ALLOWANCE (CURRENT COST, REAL, $M)

Year commencing 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
O&M expend for Alt 2	2.93	2.93	2.93	2.93	2.93	3.14	3.14	2.93	2.93	2.93
Debt & equity issuance	0.31	0.30	0.29	0.29	0.28	0.27	0.26	0.25	0.25	0.24
Operating expenditure	**3.24**	**3.23**	**3.22**	**3.22**	**3.21**	**3.41**	**3.40**	**3.18**	**3.18**	**3.17**

Values are in July 2005 dollars.

6.5 Revenue path

Results of the Commission’s revenue model for Directlink are summarised in Table 6.6 given the revenue components described in this Application.

Table 6.6

DIRECTLINK’S ESTIMATED REVENUE PATH (HISTORICAL COST, NOMINAL, $M)

Year commencing 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Opening asset value	135.6	135.4	135.1	134.7	134.2	133.6	132.8	132.0	131.0	129.9
Return on capital	12.4	12.4	12.4	12.3	12.3	12.2	12.2	12.1	12.0	11.9
Return of capital	0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.2
Operating expenditure	3.3	3.4	3.5	3.6	3.6	4.0	4.0	3.9	4.0	4.1
Tax payable	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5
Imputation credits	-0.6	-0.6	-0.6	-0.6	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7
Unadjusted revenue allowance	**16.5**	**16.7**	**16.9**	**17.0**	**17.2**	**17.6**	**17.7**	**17.6**	**17.8**	**17.9**
Smoothed maximum allowable revenue	**16.5**	**16.7**	**16.9**	**17.0**	**17.2**	**17.4**	**17.6**	**17.7**	**17.9**	**18.1**

Values are in nominal dollars.

This represents a nominal annual revenue of $16.5M to $18.1M over 10 years. This 10-year revenue stream has a present value of around $114M assuming a nominal WACC of 9.16% on 1 July 2005.

The equivalent current cost, real dollar expression of this revenue stream is set out below.

Table 6.7

DIRECTLINK'S ESTIMATED REVENUE PATH (CURRENT COST, REAL, $M)

Year commencing 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Opening asset value	135.6	132.0	128.5	125.0	121.4	117.9	114.4	110.8	107.3	103.8
Return on capital	8.76	8.53	8.30	8.08	7.85	7.62	7.39	7.16	6.94	6.71
Return of capital	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53
Operating expenditure	3.24	3.23	3.22	3.22	3.21	3.41	3.40	3.18	3.18	3.17
Tax payable	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.14	1.13
Imputation credits	-0.58	-0.58	-0.58	-0.58	-0.58	-0.57	-0.57	-0.57	-0.57	-0.57
Unadjusted revenue allowance	**16.1**	**15.9**	**15.6**	**15.4**	**15.2**	**15.1**	**14. 9**	**14. 5**	**14.2**	**14.0**
Smoothed maximum allowable revenue	**16.1**	**15.9**	**15.6**	**15.4**	**15.2**	**15.0**	**14.7**	**14.5**	**14.3**	**14.1**

Values are in January 2005 dollars

6.6 Performance incentive scheme

Consistent with the Commission's Service Standard Guidelines[79], the Directlink Joint Venturers propose that part of their allowed revenues be placed at risk as an incentive to meet a benchmarked level of performance in terms of circuit availability in peak and off-peak periods. In the case of Directlink, the performance measure of transmission circuit availability captures all of Directlink's appropriate service attributes.

The Directlink Joint Venturers will submit to the Commission the detail of its proposed performance incentive scheme in a separate submission.

6.7 Pass through rules

The Directlink Joint Venturers have endeavoured to identify all the efficient costs associated with the provision of Directlink's prescribed service, including the procurement of appropriate insurance. However, events could occur that are outside of the owners' control and that could substantially increase their costs and/or decrease the value of its regulatory asset base.

The Directlink Joint Venturers propose that, on the occasion that one of the following identified events occurs, the owners would seek adjustment of its maximum allowable revenue and/or a capital expenditure program, in accordance with pass-through rules approved by the Commission, to enable these costs to be passed-through:

[79] ACCC, Decision: Statement of Principles for the Regulation of Transmission Revenues: Service Standard Guidelines ('**Service Standard Guidelines**'), 12 November 2003.

Service standards event—Any change to the scope of standards or benchmark levels to which the Directlink Joint Venturer's maximum allowable revenue would be indexed, including changes to the National Electricity Code, and relevant decisions of the NECA, NEMMCO, the Commission or any Commonwealth or State Government;

Change of tax event—Any change to the scope or levels of tax payable by the Directlink Joint Venturers;

Terrorism event—Any act of terrorism, which includes threats associated with terrorism; and

Insurance event—Any material change to the extent of available cover or cost of insurance, relative to that forecast as part of the Directlink Joint Venturer's revenue path.

Appendix H contains the pass-through rules that would be appropriate for Directlink.

Appendix A

Glossary, Abbreviations, Terms and Acronyms

This glossary supplements, and in some case duplicates, definitions contained in Chapter 10 of the National Electricity Code.

ABB	ABB Power Systems AB of Sweden
AC	alternating current electrical energy
ACCC	Australian Competition and Consumer Commission
Application	this application and all appendices to this application
BRW	Burns and Roe Worley Pty Ltd
CAPM	capital asset pricing model
CIGRÉ	International Council on Large Electric Systems
Code	National Electricity Code
Commission	Australian Competition and Consumer Commission
CPI	consumer price index
Coordinating NSP	[a] Coordinating network service provider who is responsible for the allocation of all relevant aggregate annual revenue requirements within a region with multiple transmission network owners, and appointed under clause 6.3.2(b) of the Code
DC	direct current electrical energy
Directlink	the underground HVDC transmission system between Mullumbimby and Bungalora (80 kV DC) and between Bungalora and Terranora (110 kV AC), which forms one of the links between the New South Wales and Queensland electricity regions of the NEM
Directlink Joint Venturers	Emmlink Pty Ltd and HQI Australia Ltd Partnership, collectively
Emmlink	Emmlink Pty Limited, a subsidiary of Country Energy
Energex	Energex Limited, a distribution network owner and distribution network service provider whose network assets are located in the south east part of the Queensland market region.
energy benefits	the economic benefits to the NEM that Directlink creates by reducing fuel and operating and maintenance costs, and avoiding voluntary load shedding
ERM	Environmental Resources Management
ECS	emergency control scheme
ETS	emergency tripping scheme

HQI	Hydro Québec International Inc.
HQIA	HQI Australia Pty Limited, a subsidiary of HQI
HQIAP	HQI Australia Limited Partnership, a subsidiary of HQIA
HVDC	high voltage direct current
HVDC Light	the latest ABB Power Systems HVDC transmission technology
IOWG	Interconnection Options Working Group
IRPC	Inter-regional Planning Committee
kV	kilovolt, a unit of electrical voltage equivalent to 1,000 volts
LRMC	long run marginal cost
MAR	maximum allowable revenue
merchant entry generation benefits	the economic benefits to the NEM that Directlink creates by deferring new merchant entry generation
MVAr	megavolt-amperes reactive, a unit of reactive power equivalent to 1,000,000 volt-amperes reactive
MW	megawatts, a unit of real power equivalent to 1,000,000 watts
NECA	National Electricity Code Administrator Limited
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
net market benefit	the net present value of the gross market benefits that an augmentation provides to all those who produce, distribute and consume electricity in the NEM, less the full life-cycle cost of the augmentation
net present value	the value of a past or projected income and expenditure cash flow, at a particular point in time, given the time value of money, which is expressed as a discount rate.
NSP	network service provider
ODRC	optimised depreciated replacement cost, also known as ‘DORC’, which means depreciated optimised replacement cost
PI	performance incentive
Powerlink	Powerlink Queensland, a transmission network owner and transmission network service provider whose network assets are located in the Queensland market region
prescribed services	transmission services provided by transmission network assets or associated connection assets to which the revenue cap applies
RAB	regulatory asset base
Regulator	unless otherwise stated in this application, the Australian Competition and Consumer Commission

regulatory control period	a period in which a revenue cap is imposed on a transmission network owner by ACCC
reliability entry generation benefits	the economic benefits to the NEM that Directlink creates by deferring new reliability entry generation that NEMMCO would procure in its role as the reserve trader
residual reliability benefits	the economic benefits to the NEM that Directlink creates by reducing expected unserved energy
revenue cap	the maximum allowed revenue for each year of a regulatory control period determined by the Regulator for prescribed services applicable to a transmission network owner
NCAS	network control ancillary service
network deferral benefits	the economic benefits to the NEM that Directlink creates by deferring major transmission augmentations in the Queensland and New South Wales regions
NSA	network support agreement
SRMC	short run marginal cost
TEA	TransÉnergie Australia Pty Limited
TEUS	TransÉnergie US Limited
TNSP	transmission network service provider
TransGrid	TransGrid, a transmission network owner and transmission network service provider whose network assets are located in the New South Wales market region.
unserved energy	the amount of energy, measured in megawatt-hours, that can not be supplied because of either (i) a NEM-wide shortage of operating generating capacity, or (ii) a lack of transmission capacity to transfer energy from generators with spare generating capacity to locations at which that energy is demanded
URS	URS Australia Pty Ltd
WACC	weighted average cost of capital
X factor	the extent by which a TNSP’s smoothed revenue requirement decreases each year in real terms, expressed as a percentage
$	Australian dollars

Appendix B

Principal References

Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, ('**Draft Regulatory Principles**'), 27 May 1999.

Australian Competition and Consumer Commission, Regulatory Test for New Interconnectors and Network Augmentations, 15 December 1999.

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Australian Competition and Consumer Commission, *Draft Decision, Statement of Principles for the Regulation of Electricity Transmission Revenues* (‘**SRP Draft Decision**’), 18 August 2004.

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National Electricity Code Administrator Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors 1998, *Entrepreneurial Interconnectors: Safe Harbour Provisions* (‘**Safe Harbour Provisions**’), November 1998.

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National Electricity Market Management Company Limited, *Statement of Opportunities 2003 for the National Electricity Market*, July 2003.

Appendix C

Tables and Figures

Tables

Figures

Appendix D

BRW Report

Burns and Roe Worley, *Directlink, Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*, 22 September 2004

Appendix E

URS Report

URS Australia Pty Ltd, *Alternative Projects to the Directlink Transmission Line – Environmental Review: Mullumbimby to Terranora (New South Wales)*, 9 March 2004

Appendix F

Letter from Tweed Council

Letter from Mr Douglas Jardine of Tweed Council to Mr Dennis Stanley of Council Energy dated 14 April 2004.

Please Quote Council Ref: Town Planning - General

[spltr]

Your Ref No:

For Enquiries Please Contact: Mr Eber Butron

Telephone Direct (02) 6670 2649

14 April 2004

Mr Dennis Stanley
Manager
Directlink Joint Venture
Emmlink Pty Ltd
PO Box 5118
PORT MACQUARIE NSW 2444

Dear Mr Stanley

Directlink Transmission Line - Environmental Review: Mullumbimby to Terranora (NSW) Prepared by Burns & Roe Worley - URS.

I refer to the above document and your request for Council advice on the subject report.

Council wishes to acknowledge that the above report identifies and addresses environmental and planning issues relevant to the project and the study area. The desktop analysis provided by the report provides a good assessment of the issues and regulatory requirements Council considers significant to the project. Council also concurs with the report in that the desktop analysis generally provides the first level of assessment that would need to be supported by more site specific survey and by an array of detailed site reports, assessment and field investigations.

Council also supports the need for community consultation for the project. It also recommends that further advice on the project be sought from relevant State Agencies.

Should you have any further queries regarding this matter please contact Eber Butron on the above telephone number.

Yours faithfully

Douglas Jardine
Manager, Strategic Planning
Development Services Division

File No.		
OBJ ID		
Action Officer	Dennis Stanley.	
30 APR 2004		
Pages Scanned	Attachment	Original Despatched
/	N	N

Appendix G

TEUS Reports

Part 1 - TransÉnergie US Limited, *Estimation of Directlink Alternative Projects' Market Benefits*, April 2004

and

Part 2 - TransÉnergie US Limited, *Estimation of Directlink Alternative Projects' Market Benefits – Supplementary Report*, 15 September 2004

Appendix H

Pass Through Rules

1. REGULATED PASS THROUGH

1.1 Rules form part of revenue cap

These Pass Through Rules form part of the revenue cap set by the Commission to apply to the DJV for the regulatory control period commencing on [***date to be inserted when known***]. Any Pass Through Amount approved under these Pass Through Rules forms part of the revenue cap.

1.2 Pass Through Event

Each of the following is a Pass Through Event:

(a) a Change in Taxes Event;

(b) a Service Standards Event;

(c) a Terrorism Event; and

(d) an Insurance Event.

1.3 Entitlement to pass through

If a Pass Through Event occurs, the Directlink Joint Venturers are entitled or may be required to amend the revenue cap to pass through the financial effect of the Pass Through Event in accordance with the procedures set out in these Pass Through Rules.

1.4 Form of Pass Through Amount

A Pass Through Amount will reasonably reflect the factors in clause 3.4 and be expressed as an increase or decrease in the amount of the revenue cap (with its Relevant Coordinating Network Service Providers to determine the corresponding change in transmission charges in accordance with the Code).

2. ANNUAL INSURANCE INFORMATION

2.1 The Directlink Joint Venturers to provide annual insurance information

The Directlink Joint Venturers will provide to the Commission a copy of insurance premium invoices at least 50 business days before the start of each financial year.

3. PROCEDURE

3.1 Initiation of pass through

(a) If Commission believes the Directlink Joint Venturers is or will be entitled or required to pass through the financial effect of a Pass Through Event, it may instruct the Directlink Joint Venturers to give a Notice of Proposed Pass Through to the Commission in relation to a Pass Through Event specified by the Commission.

(b) If Commission instructs the Directlink Joint Venturers give a Notice of Proposed Pass Through to the Commission in relation to a Pass Through Event specified by the Commission, the Directlink Joint Venturers will do so in accordance with clause 3.2.

(c) If the Directlink Joint Venturers believe it is or will be entitled or required to pass through the financial effect of a Pass Through Event, then it may give a Notice of Proposed Pass Through to the Commission in accordance with clause 3.2.

3.2 Notice of Proposed Pass Through

A Notice of Proposed Pass Through will include:

(a) details and documentary evidence of the relevant Pass Through Event;

(b) the date on which the relevant Pass Through Event took effect or will take effect;

(c) the estimated financial effects of the Pass Through Event on the provision of revenue capped transmission services; and

(d) the Pass Through Amount proposed by the Directlink Joint Venturers in respect of the relevant Pass Through Event.

3.3 Determination by the Commission

(a) The Commission will, within the Assessment Period, determine whether the Pass Through Event specified in the Notice of Proposed Pass Through did occur (or will occur).

(b) If the Commission determines that the Pass Through Event did occur (or will occur), the Commission will determine:

  (i) the Pass Through Amount in respect of the relevant Pass Through Event; and

  (ii) the date from, and period over which, the Pass Through Amount may be applied, and notify the Directlink Joint Venturers in writing of the Commission's decision.

(c) If the Commission does not give a notice to the Directlink Joint Venturers under clause 3.3(b)(ii) within the Assessment Period, then the Commission is taken to have notified the Directlink Joint Venturers of its determination that:

(i) the relevant Pass Through Event has occurred (or will occur); and

(ii) the Pass Through Amount and form of the Pass Through Amount are as specified in the Notice of Proposed Pass Through given by the Directlink Joint Venturers under clause 3.2.

3.4 Relevant Factors

In making a determination under clause 3.3, the Commission must seek to ensure that the financial effect on the Directlink Joint Venturers associated with the Pass Through Event concerned is economically neutral taking into account:

(a) the relative amounts of revenue capped transmission services provided by the Directlink Joint Venturers;

(b) the time cost of money for the period over which the Pass Through Amount is to be applied;

(c) the financial effect on the Directlink Joint Venturers associated with the provision of revenue capped transmission services attributable to the Pass Through Event and the time at which the financial effect took place or will take place;

(d) in relation to a Change in Taxes Event:

(i) the amount of any increase or reduction in another tax, rate, duty, charge, levy or other like or analogous impost intended to offset in whole or in part the relevant Change in Tax Event and the manner in which and the period of over which that increase or reduction occurs; and

(ii) the amount included in the operating expenses or other cost inputs of the Directlink Joint Venturers' revenue cap;

(e) in relation to a Terrorism Event, any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with:

(i) the Terrorism Event; or

(ii) any action taken in controlling, preventing, suppressing or in any way relating to the Terrorism Event;

(f) in relation to an Insurance Event:

(i) the amount of any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with the Insurance Event and including without limitation:

(A) the cost of any material increase or decrease in premium paid or payable by the Directlink Joint Venturers beyond that provided for in the Directlink Joint Venturers' revenue cap;

(B) the cost of any material increase or decrease in deductible paid or payable by the Directlink Joint Venturers beyond that provided for in the Directlink Joint Venturers' revenue cap; and

(C) if an Insurance Event occurs and the Directlink Joint Venturers either does not continue the relevant Insurance or continues the Insurance on different terms, losses resulting from any uninsured event or partially uninsured event where that event would have been insured or fully insured by Insurance at the date of the Determination, and

(ii) the economic consequences for the Directlink Joint Venturers of a decision to Self Insure.

(g) in relation to a Service Standards Event, the financial effect on the Directlink Joint Venturers associated with any increased or decreased costs or risks (including in the nature, scope or asymmetry of risks) resulting from the Service Standards Event including, where relevant, an appropriate self insurance allowance relating to the increased risks.

3.5 Application of Pass Through Amount

Within 10 business days of the Directlink Joint Venturers receiving or taking to have received a notice under clause 3.3 determining a Pass Through Amount, the Directlink Joint Venturers will notify its Relevant Coordinating Network Service Providers of:

(a) the Pass Through Amount; and

(b) the date from and period over which the Pass Through Amount will apply,

4. INFORMATION DISCLOSURE

4.1 Non-confidential information

Unless designated by the Directlink Joint Venturers as confidential, the Commission may disclose publicly information provided to it by the Directlink Joint Venturers under clauses 2.1 and 3.2 of these Pass Through Rules.

4.2 Confidential information

If the Directlink Joint Venturers designates as confidential any information provided to the Commission under clauses 2.1 and 3.2 of these Pass Through Rules, the

Commission will not disclose publicly that information, subject to clause 6.2.6 of the Code.

5. DEFINITIONS

The terms in these Pass Through Rules have the same meaning as in Chapter 10 of the National Electricity Code and in the Directlink Joint Venturers' Application to the Commission of [***date to be inserted when known***].

5.1 Additional Definitions

Applicable Law means any legislation, delegated legislation (including regulations), codes, licences or guidelines relating to the provision of one or more revenue capped transmission service, and includes the National Electricity Code and the National Electricity Law.

Assessment Period means 40 business days from the date the Commission receives from the Directlink Joint Venturers a Notice of Proposed Pass Through or a period not longer than 80 business day determined by the Commission at its discretion.

Authority means any government or regulatory department, body, instrumentality, minister, agency or other authority or any body which is the successor to the administrative responsibilities to that department, body, instrumentality, minister agency or authority, and includes the Independent Pricing and Regulatory Tribunal of New South Wales, NEMMCO, NECA and the Commission, or their successors.

Change in Taxes Event means:

(a) a change in the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of Relevant Tax);

(b) the removal of a Relevant Tax or imposition of a new Relevant Tax,

to the extent that the change, removal or imposition:

(c) occurs after the date of the Determination; and

(d) results in a change in the amount the Directlink Joint Venturers are required to pay or is taken to pay (whether directly, under any contract or as part of the operating expenses or other cost inputs of the Directlink Joint Venturers' revenue cap) by way of Relevant Taxes.

Determination means the determination of the Commission setting the revenue cap for the Directlink Joint Venturers in relation to the regulatory control period commencing on [***date to be inserted when known***].

Insurance means insurance whether under a policy or a cover note or other similar arrangement:

(a) for risks of the sort for which the Directlink Joint Venturers was covered at the date of the Determination;

(b) for amounts not less than amounts underwritten in favour of the Directlink Joint Venturers at the date of the Determination; and

(c) on terms, including without limitation terms specifying deductibles payable and any applicable exclusions, no less favourable to the Directlink Joint Venturers than the terms in place at the date of the Determination.

Insurance Event means where one or more of the following circumstances occurs:

(a) where Insurance in respect of any risk becomes unavailable to the Directlink Joint Venturers;

(b) where Insurance in respect of any risk becomes unavailable to the Directlink Joint Venturers at reasonable commercial rates;

(c) where Insurance in respect of any risk becomes unavailable to the Directlink Joint Venturers on terms which are at least as favourable to the Directlink Joint Venturers as those generally available at the date of the Determination;

(d) where the cost of Insurance (including, without limitation, premiums and deductibles) in respect of any risk becomes materially higher or lower than the cost of Insurance at the date of the Determination;

(e) where an insurance benefit payment to the Directlink Joint Venturers under its Insurance in respect of any risk is reduced by a deductible amount; or

(f) where an insurance benefit payable to the Directlink Joint Venturers under its Insurance in respect of any risk is not paid to the Directlink Joint Venturers due to the business failure of an insurer.

Notice of Proposed Pass Through means a notice described in clause 3.2.

Pass Through Amount means a variation to the Directlink Joint Venturers' revenue cap as a result of a Pass Through Event determined in accordance with these Pass Through Rules.

Relevant Tax means any tax, rate, duty, charge, levy or other like or analogous impost that is:

(a) paid, to be paid, or taken to be paid by the Directlink Joint Venturers in connection with the provision of transmission services, or:

(b) included in the operating expenses or other cost inputs of the Directlink Joint Venturers' revenue cap;

but excludes

(c) income tax (or State equivalent tax) or capital gains tax;

(d) penalties and interest for late payment relating to any tax, rate duty, change, levy or other like or analogous impost;

(e) fees and charges 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 or other like or analogous impost that replaces the taxes or charges referred to in (c) to (f).

Self Insure means where the Directlink Joint Venturers elect, following the occurrence of an Insurance Event, to self insure for all or part of a risk of the sort for which the Directlink Joint Venturers previously maintained Insurance.

Service Standards Event means a decision made by the Commission or any other Authority or any introduction of or amendment to an Applicable Law after the date of the Determination that:

(a) has the effect of:

(i) imposing or varying minimum standards on the Directlink Joint Venturers relating to revenue capped transmission services that are different to the minimum standards applicable to the Directlink Joint Venturers in respect of revenue capped transmission services at the date of the Determination;

(ii) altering the nature or scope of services that comprise the revenue capped transmission services;

(iii) substantially varying the manner in which the Directlink Joint Venturers is required to undertake any activity forming part of revenue capped transmission services from date of the Determination; or

(iv) increasing or reducing the Directlink Joint Venturers' risk in providing the revenue capped transmission services, and

(b) results in the Directlink Joint Venturers incurring (or being likely to incur) materially higher or lower costs in providing revenue capped transmission services than it would have incurred but for that event.

Terrorism Event means an act, including but not limited to the use of force or violence and/or the threat thereof, of 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.

5.2 References to certain general terms

Unless the contrary intention appears, a reference in these Rules to:

(a) (**variations or replacement**) a document (including these Rules) includes any variation or replacement of it;

(b) (**clauses, annexures and schedules**) a clause, annexure or schedule is a reference to a clause in or annexure or schedule to these Rules;

(c) (**reference to statutes**) a statute, ordinance, code 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, joint venture, syndicate, an unincorporated body or 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.

5.3 Headings

Headings (including those in brackets at the beginning of paragraphs) are for convenience only and do not affect the interpretation of these Rules.