PB ASSOCIATES

REVIEW OF DIRECTLINK CONVERSION APPLICATION

Final Report

Prepared for

The Australian Competition and Consumer Commission

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DISCLAIMER

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The preparation of this report has necessitated projections of the future, which are inherently uncertain, and our opinion is formed based on the underlying representations, assumptions and projections detailed in this report. There will usually be differences between projected and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We do not express an opinion as to whether actual results will approximate projected results, nor can we confirm, underwrite or guarantee the achievability of the projections as it is not possible to substantiate assumptions which are based on future events and we make no warranty to any third party in regard to the contents of this report.

EXECUTIVE SUMMARY

This report has been prepared by Parsons Brinckehoff Associates (PB Associates) for the Australian Competition and Consumer Commission (Commission) in relation to the Directlink Joint Venture (DJV) application for conversion to a regulated interconnector. This report addresses the Commission's requirements to identify the necessary network services delivered by Directlink as well as the range and costs of feasible alternatives available to provide the market with equivalent services.

This report is intended to assist the Commission in evaluating the benefits of Directlink and comparable feasible alternatives through the application of the Regulatory Test, which can then be applied to develop charges that would be applicable should Directlink convert to a regulated status.

PB Associates commenced its review for the Commission in May 2004 following the submission of the original application by the DJV. In August 2004, the DJV advised that they wished to resubmit their application in order to make material changes and with the intention of providing a new application. The Commission therefore suspended the review being undertaken by PB Associates pending receipt of the DJV's revised application. This revised application was received in September 2004 and incorporated significant variations to the technical capabilities of Directlink.

In line with the Commission's terms of reference for this review, this report contains 2 core sections:

1. An analysis of the need and justification for the services provided by Directlink; and
2. An evaluation of the range and costs of alternatives available to provide equivalent services.

The process employed by PB Associates in undertaking this review included analysis of the DJV's application and supporting information, research into the Murraylink decision and the Commission's Code obligations, and consultation with key stakeholders.

The key findings and observations of this review include:

- Directlink was constructed specifically for the purposes of trading energy between the NSW and Queensland markets and not as an integrated element for overcoming local transmission network capacity constraints within the NSW and Queensland regions. Its characteristics, size and location are not consistent with optimal longer term network planning requirements for the transmission system.
- At present Directlink is capable of providing support to the Queensland network to enable alternate supply during peak demand. In summer 2005/06, demand may exceed the required capabilities of the Queensland transmission network in the event of a contingency. Powerlink and DJV have a commercial agreement for network support from Directlink during that period believed to be valued at $2.7m. Powerlink has commenced work to upgrade the Queensland transmission system so that this support is not required beyond October 2006. A deferral benefit has also been calculated for the Queensland augmentations for consistency.
- The NSW transmission system is not dependent on the capacity offered by Directlink for network support at the present time in meeting its requisite reliability levels.
- NEMMCO has an agreement with Directlink for the supply of reactive power. This is a commercial arrangement which NEMMCO is expected to be maintained. This contract between NEMMCO and DJV, which is formulated based on Directlink operating as a competitive service provider, could be assumed to remain outside of the regulated revenues of the business following conversion.
- TransGrid has advised that the supply capabilities of the existing NSW transmission network for northern NSW will approach its limits in 2006/07 in the absence of any additional network support. They have identified a number of relatively small capital investments which maintain network capabilities until after 2007/08. Directlink, along

with other potential alternatives identified by TransGrid, could provide network support to maintain network reliability standards beyond this period and defer major transmission augmentations.

- PB Associates believes that DJV has correctly identified the range of alternatives available to provide equivalent network support to that offered by Directlink. The key alternatives include:
  - DC link using HVDC Light® technology (Alt1);
  - DC link using conventional HVDC technology (Alt 2);
  - AC link using a PST (Alt 3);
  - AC link using a convention auto transformer (Alt 4);
  - State based AC augmentations in NSW and Qld (Alt 5);
  - Demand management and/or embedded generation.
- Alternative 5 is likely to proceed at some stage in the future in order to provide a long term solution to supply requirements for this region. This project has therefore been considered by PB Associates as the “Reference Case” against which the technical benefits of the other solutions have been compared. It does not represent a comparable alternative.
- In reviewing demand management and embedded generation opportunities PB Associates has included these impacts in the evaluation of timing and deferral benefits of Alternative 5 which is considered the reference case in this report.
- The inter-regional transfer capabilities of QNI plus Directlink and the viable alternatives can be summarised as follows: (note: the southerly flow figures are not applicable to alternatives 0, 1, 2 in 2005/06 at high demand due to pre-contingent flows north).

Table 1-1 – Power Transfer Limits (Medium Growth Scenario - Peak Load Conditions at 2006/07)

	Alt 0	Alt 1	Alt 2	Alt 3	Alt 5
Northerly flow capacity limit	300MW	300MW	300MW	300MW	300MW
Southerly flow capacity limit	1,092MW	1,092MW	1,092MW	948MW	950MW

- Alternative 5; state based major augmentations, has been modified in this report by PB Associates to take account of the developments which are expected to proceed regardless of Directlink. These are:
  - upgrading of Armidale to Koolkhan 132 kV line 966 and installation of capacitors at TransGrid, Koolkhan, Lismore and Nambucca substations;
  - network support from a 30MW generator at Broadwater Mill in Northern NSW.

  The effect of this is to defer the need for major augmentations by TransGrid. This reduces the potential augmentation deferral value of the defined Alternatives relative to Alternative 5. – i.e. reduced benefits.
- Efficient capital and operation costs of Alternatives 0, 1, 2, 3 and 5 have also been estimated by PB Associates and generally these costs are lower than those submitted by DJV.
- PB Associates recommends that Alternative 3, as described, does represent a technically possible alternative to Directlink and should therefore be considered.

- Alternative 4 has significant limitations being a traditional AC link, effectively operating in parallel with an interconnector of significantly higher rating. PB Associates agrees with DJV that this Alternative is not a credible Alternative to Directlink.
- No other credible Alternatives were identified by PB Associates.
- Capital and operating costs for each of the alternatives have been estimated as per the following table:

Table 1-2 – PB Associates estimate of capital and operating costs of alternatives – July 2005 dollars ($M)

	Alternative 0	Alternative 1 (OH)	Alternative 2 (OH)	Alternative 3 (OH)	Alternative 5 (NSW & Qld)
Capital Costs	138.8	111.0	116.5	41.0	178.8
Annual Operating Expenditure	1.56	1.56	1.56	0.49	1.53

- In essence PB Associates is of the view that the network service benefits offered by Directlink lie only in its ability to defer the construction of Alt 5 (Queensland augmentations for one year and the new Dumaresq to Lismore 330kV line). PB Associates estimates that without Directlink the NSW augmentations would commence in 2010/11 so as to be available in 2011/12. Directlink then enables potential deferral until 2016/17. Given that planning periods extend only for 10 years, however, and considerable uncertainty exists beyond this period, the deferral benefit is assumed to last only until 2014/15, i.e. 10 years from conversion.
- The deferral periods for each alternative are shown in the following table:

Table 1-3 – Alternative 5 Deferrals offered by each Alternative

	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
Qld Deferrals	2005/06	2005/06	2005/06	0	NA
NSW Deferrals	2011/12 – 2014/15	2011/12 – 2014/15	2011/12 – 2014/15	0	NA

The present value calculation of this deferral is:

Table 1-4 –Alternative 5 Present Value Costs NSW Deferrals– 2005 dollars ($m)

NSW Deferrals	7%	9%	11%
Without Directlink (Alt 0, 1, or 2)	$91.43	$80.97	$72.07
With Directlink (Alt 0, 1, or 2)	$69.75	$57.36	$47.48
Transmission Deferral Benefit of Directlink	$21.68	$23.61	$24.60

Table 1-5 – Alternative 5 Present Value Costs Qld Deferrals – 2005 dollars ($m)

Qld Deferrals	7%	9%	11%
Without Directlink (Alt 0, 1 or 2)	$49.88	$49.88	$49.88
With Directlink (Alt 0, 1 or 2)	$46.61	$45.76	$44.94
Transmission Deferral Benefit of Directlink	$3.26	$4.12	$4.94

- Deferral benefits of the Queensland augmentations could be based on the commercial service agreement understood to be valued at $2.7m.
- PB Associates is of the view that the performance and remuneration for Directlink should be based on the reliable capacity offered and the subsequent transmission deferments achieved. Thus the regulated income should be reduced or increased on the basis of the percentage reliability actually achieved relative to the estimated reliability assumed.
- PB Associates has reviewed Directlink's outage history and understands that substantial capital works are required in order to achieve reliability levels necessary to defer the NSW augmentations of Alternative 5.

In addition to these key findings, there are a number of issues which were noted by PB Associates during this review. These include:

- Powerlink, TransGrid and Country Energy have not undertaken detailed modelling of load requirements and network investments beyond a 10 year horizon, This is considered reasonable, however it does present challenges for reviewing the benefits offered by Directlink beyond that time as the range of alternatives and the variability of key assumptions (loads, embedded generation, environmental issues, standards, regulatory requirements, etc) can significantly change the role Directlink could play in supporting the network. The Commission needs to consider the value offered at this time by Directlink in the light of those uncertainties and appropriate mechanisms for adjusting allowable revenues in the future based on actual outcomes experienced. In the absence of a performance based discipline on the regulatory outcome for Directlink there is an asymmetric risk that the asserted benefits of the interconnector do not manifest in the timeframe assumed.
- To the knowledge of PB Associates, DJV has not entered into commercial negotiations with TransGrid for the provision of network support services through Directlink at this time. Given that TransGrid has indicated that network augmentations are required from 2007 to maintain supply, in the absence of other initiatives, and that the timeframe for major upgrades (including the proposed 330 kV line from Lismore to Dumaresq) would require up to 5 years for approvals, environmental assessments and construction, it is apparent that TransGrid do not anticipate requiring Directlink within that timeframe.

1. INTRODUCTION

Parsons Brinckerhoff Associates, ("PB Associates") has been appointed by the Australian Competition and Consumer Commission ("the Commission") to establish a suite of feasible investment alternatives that would deliver equivalent levels of network services to those offered by the Directlink electrical network, to the extent that those services are required. Directlink provides a 180MW DC link between the New South Wales (NSW) and Queensland (QLD) transmission systems. The Commission is seeking to determine the effectiveness of the Directlink interconnector in serving the needs of customers and also its relative level of efficiency. The findings of the PB Associates review are required for a subsequent study to assess the market benefit of each feasible alternative.

1.1 PROJECT BACKGROUND

Directlink was constructed in 1999/2000 to enable energy to be supplied between the QLD and NSW electricity markets. At that time there were significant variations between the electricity prices in the two pools and the intention of Directlink was to offer a physical interconnection to enable available generation within NSW and QLD to access both markets.

Directlink was constructed as a "merchant" interconnector – deriving its income by trading its capacity into the market and seeking to arbitrage the price differentials which were being experienced (intermittently) between the NSW and QLD electricity pools.

The concept of an entrepreneurial interconnector is usually applicable where a network constraint exists which prevents generator competition from balancing market prices. In relation to Directlink, once the QLD/NSW interconnector (QNI) was constructed by TransGrid and Powerlink, it offered substantially greater capacity than that of Directlink, and effectively eliminated much of the price differential between the NSW and QLD electricity pools for most of the year. The potential for Directlink to derive unregulated income was therefore substantially diminished.

The Directlink Joint Venture Partners ("the DJV") have applied to the Commission to have the Directlink interconnector declared as 'regulated network'. This would allow the DJV to derive a prescribed level of income in a similar manner to that derived by other regulated transmission companies in the National Electricity Market (NEM). These costs would be passed through to retailers and customers based on network use of system rates applicable.

1.2 PROJECT SCOPE

This report assesses the appropriateness of the alternative projects identified by the DJV for the purposes of applying the regulatory test assessment. This review is intended to facilitate the Commission's determination on whether:

1. there is a justifiable need for the investment; and
2. the most efficient investment to meet that need has been selected.

The review is premised on ensuring that all alternatives provide a minimum level of network reliability so that comparisons of market value are consistent and valid. Reliability in excess of minimum network requirements should not be assigned additional market benefits on this basis alone. There are three key aspects considered in this report relating to the Commission's requirements. These are:

- justification for the investment;

- efficiency of the selected option; and
- additional project requirements.

Each of these is described further below.

1.2.1 Justification for the investment

The need for the investment refers to the determination of whether the DJV has correctly identified the network limitations in the QLD and NSW networks and the role Directlink plays in assisting to overcome these limitations. This requires consideration of loads, capacity requirements, voltage stability, fault levels and other technical and environmental issues. The potential for non-network solutions such as embedded generation or demand management must also be considered. In essence the question is what happens to the service capabilities of the network if Directlink is removed?

To satisfy these criteria Directlink must be shown to be a necessary component of the network in the region and provide useful levels of supply capability. Providing services in excess of appropriate design standards would not necessarily constitute a demonstrable justification for the investment. Likewise, if alternative avenues are available to Country Energy, TransGrid or Powerlink to provide supply in the region without support from Directlink, then the arguments for the interconnector investment may be weakened.

DJV has stated that Directlink is capable of providing 5 fundamental network services. These are the:

- transfer of active power between Mullumbimby and Terranora, in both directions
- transfer of reactive power in both directions and provides voltage control[1];
- provision of network support to the Gold Coast and North Coast of NSW which could defer other network augmentations;
- provision of inter-regional flows between NSW and QLD that bring efficiency and reliability benefits to the NEM; and
- enhancement of stability and security of supply – particularly in NSW and QLD.

This review has sought to validate that these services are delivered by Directlink and that they are technically justifiable.

The key aspects covered by PB Associates in reviewing the need for the investment include:

1. a review of data and alternatives proposed by DJV, including historical data demonstrating that Directlink is able to provide the services claimed by DJV;
2. a review of load data that underpins these proposed alternatives, including growth, asset age and condition, voltage and fault levels; reliability data, etc;
3. identification of key load and network characteristics that need to be taken into consideration in determining possible alternatives;

[1] As technical point of clarification – reactive power is not transferred between Mullumbimby and Terranora. All reactive power is generated and/or absorbed at each end independently. i.e. Mullumbimby could be exporting reactive power at the same time that Terranora is exporting reactive power. Effectively, both ends act as independent Static Var Compensators (SVCs).

4. identification of non-network factors that could influence the feasibility of various options, such as environmental issues, easement access and community concerns;

5. an assessment of the full range of supply alternatives that might be employed to reduce or avoid dependence on Directlink;

6. a detailed assessment of the levels of network services delivered by the DJV proposals; and

7. consideration of the levels of services potentially provided by alternatives not advocated by DJV.

1.2.2 Efficiency of the selected option

Selection of the most efficient investment requires consideration of whether the technical specifications of the alternative projects identified by DJV are appropriate to meet the identified need; whether all available and appropriate alternatives have been considered and included; the relative levels of service (and design standard) and risk provided by each alternative; and the efficient levels of costs that are applicable to each feasible alternative.

Consideration of the most efficient alternatives for the Directlink interconnector has involved assessment of both technical and financial issues. PB Associates has undertaken this review cognisant of the need to ensure that:

1. the technical efficiencies of all viable alternatives are evaluated;

2. the service deliverables are quantified in a manner that enables comparisons of all viable alternatives that are consistent with the requirements of the National Electricity Code and the Commission’s Service Standards Guidelines;

3. the costing assumptions and cashflow projections for all viable alternatives are accurate and where possible, benchmarked against similar projects;

4. non-network issues have been appropriately included into cost and efficiency estimations where quantifiable and relevant;

5. external benefits and costs are considered appropriately in efficiency and costing assessments for all viable alternatives; and

6. appropriate service standards and performance targets have been established, based on the review of Directlink’s historical performance and all relevant factors.

PB Associates has undertaken consultation with key stakeholders including the Tweed Shire Council, State and Federal Government Departments, transmission authorities, manufacturers of the various cables, construction companies experienced in cable laying and high voltage overhead lines (particularly in the north coast of NSW) and other parties who have expressed an interest in this review.

1.2.3 Additional project requirements

This review includes consideration of the appropriate service standards and performance targets to be applied, based on its assessment of Directlink’s historical performance and/or other benchmarks or factors deemed appropriate.

In consultation with the DJV and other stakeholders during the course of this review, performance measures and targets have been proposed for the project which relate directly to the expectations of the more favourable network alternatives.

2. NEED AND JUSTIFICATION FOR THE INVESTMENT

The Commission has requested PB Associates to consider whether there is a need for the investment in Directlink as part of the review of the DJV application for Directlink to be granted regulated status.

Specifically, the Commission has requested PB Associates to determine whether the DJV has correctly identified the emerging network limitations in the QLD and NSW networks, particularly the NSW North Coast and the Gold Coast region of QLD. The review considers, inter alia, load growth projections, capacity requirements, voltage, fault level and other technical and environmental issues.

In considering this component of the work PB Associates notes that it has based its investigations on the information in the application and that provided to PB Associates by the DJV and its consultants. In addition, information provided by the affected Transmission Network Service Providers (TNSPs) has been considered following on from formal discussions with both TransGrid and Powerlink.

This report relies on the information provided by various parties. PB Associates has carried out reviews of various aspects of the power system studies, underlying models and other data on which this information was based but a detailed audit of all aspects of the information provided was not conducted. Where there are discrepancies between the information provided by various parties, PB Associates has sought to clarify any differences that may have led to such discrepancies.

2.1 NEEDS AND THE REGULATORY TEST

Under the Regulatory Test[2] an augmentation satisfies the regulatory test if it either:

- meets a service standard(s) associated with the technical requirements of Section 5.1 of the National Electricity Code (“the Code”) and minimises the net present value (NPV) of the cost of meeting the service standard(s), or
- provides an alternative that maximises the NPV of market benefits whilst having regard to available alternatives.

Following various Code changes and other developments that have affected the framework governing the regulatory test, the Commission conducted a review process surrounding the mechanics of the regulatory test. In its March 2004 draft decision on the application of the regulatory test[3] the Commission refers to augmentations that are designed to meet required service standards such as reliability augmentations where the Code defines a reliability augmentation as:

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

This Section 2 of this report considers whether the Directlink asset would provide technical reliability benefits and/or market benefits and as such provide a basis for

2 ACCC, *Regulatory Test for New Interconnectors and Network Augmentations* (“Regulatory Test’), 15 December 1999.

3 ACCC, *Draft decision – Review of the Regulatory Test for Network Augmentations*, 10 March 2004.

considering the application further under the Regulatory Test of 15 December 1999 particularly as applied to the Murraylink application[4] where relevant.

The quantification of the market benefits will be considered under a separate consultancy called by the Commission and the main focus of this section of the report will be to consider the nature of the technical benefits claimed by the DJV to be delivered by the Directlink asset.

In its application and the supporting Appendix D - BRW Report[5] and Appendix G - TEUS Report [6] the DJV has applied a market benefits test in terms of assessing whether the proposed conversion meets the regulatory test.

Whilst the DJV submission does not specifically apply the service standards (or reliability augmentation) limb of the regulatory test, a significant amount of the benefits claimed by the DJV are attributable to deferral of reliability augmentation associated with the NSW transmission network. This aspect comprises a significant component of the focus of this section 2 of PB Associates' report.

2.2 MARKET BENEFITS

Section (1) (b) of the notes accompanying the regulatory test provides guidance on what should be included in a market benefit assessment. These include:

i. electricity demand (modified where appropriate to take into account demand side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);

ii. the value of energy to electricity consumers as reflected in the level of (VCR and/or) value of lost load (VoLL);

iii. the efficient operating costs of competitively supplying energy to meet forecast demand from existing, committed and modelled projects including demand side and generation projects;

iv. the capital costs of committed, anticipated and modelled projects including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;

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

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

In the DJV application the following inter-regional benefits are claimed to be provided:

[4] ACCC, Murraylink Transmission Company: *Application for Conversion and Maximum Allowed Revenue*, 1 October 2003.

[5] Burns and Roe Worley, *Directlink, Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC* ('BRW Report'), September 2004.

[6] TransÉnergie US Limited, *Estimation of Directlink Alternative Projects' Market Benefits,* ('TEUS Report'), April 2004

- energy benefits arising out of reduced costs in terms of fuel and variable operations and maintenance costs and reductions in frequency and level of voluntary load reductions;

- benefits arising from reduced capital and O& M costs due to deferral of market entry generation;

- deferred reliability entry generation benefits under the NEMMCO reserve trader provisions; and

- residual reliability benefits due to lower levels of unserved energy throughout the NEM.

In addition to these benefits the DJV has also claimed substantial benefits arising out of the deferral of reliability augmentations that would need to be undertaken by TransGrid and Powerlink to meet their obligations under Schedule 5.1 of the Code. These reliability augmentations relate to emerging constraint issues in the Gold Coast/Tweed Heads area and in northern New South Wales, in particular the Far North Coast Region.

Prima-facie, the market benefits claimed by the DJV are compatible with criteria for market benefits assessment under the regulatory test. The nature of the market benefits considered is broadly consistent with the benefits that were assessed under the Murraylink application[7] and the resulting Murraylink decision[8].

The primary focus of the balance this Section 2 of the report is to consider the technical services that the Directlink asset is able to provide and consider the potential impacts of this level of technical service on deferring reliability augmentations that are being considered by Powerlink and TransGrid.

2.3 TECHNICAL SERVICE PROVISION

The DJV has stated that Directlink is capable of providing 5 fundamental network services as summarised below:

- transfers active power between Mullumbimby and Terranora, in both directions;

- provides reactive power control at both the Mullumbimby and Terranora ends of the interconnector;

- provides network support to the Gold Coast and North Coast of NSW which could defer other network augmentations;

- provides inter-regional flows between NSW and QLD that bring efficiency and reliability benefits to the NEM; and

- enhances stability and security of supply, particularly in NSW and QLD.

Consideration is given to whether these services are delivered by Directlink and whether they are needed. Providing services in excess of appropriate design standards would not necessarily constitute a demonstrable need for the investment. Likewise, if alternative avenues are available to provide the service then the arguments for the Directlink

[7] Murraylink Transmission Company, *Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12*, 18 October 2002.

[8] ACCC, Murraylink Transmission Company: Application for Conversion and Maximum Allowed Revenue, 1 October 2003.

interconnector investment may be weakened. For example, if Country Energy, TransGrid and Powerlink were able to overcome network constraints in the region without support from Directlink then, depending on relative cost efficiencies and other factors, the value of the service provided by Directlink may by lessened.

The power transfer capability of an augmentation is a critical input into the calculation of its market benefits. The greater the transfer capability of an augmentation the greater its potential market benefits as assessed under the regulatory test. The BRW report denotes the as-tested receiving end capability of the Directlink asset of 174.9 MW as representing its total power transfer capability. However the overall ability of Directlink to transfer power is contingent on other peak load network constraints of which there are a number existing and emerging in the Gold Coast/Tweed and northern NSW areas.

The DJV have advised that there have been significant reliability issues in relation to the general availability of all of Directlink's transfer capacity due to cable joint failure issues and other technical aspects. This is clearly a concern in terms of reliability planning for the network and will influence the dependence placed on these assets in developing a network capable of prescribed reliability levels. This aspect is discussed in more detail in Section 4 of this report.

The Directlink asset is currently contracted to provide reactive power ancillary services to NEMMCO subject to the capability limitations of the asset (nominally around 55 MVAr). This contract requires that the Directlink asset either supplies or absorbs reactive power at either end to assist in maintaining the transmission network within its voltage and stability limits. Thus it is clear that the Directlink asset is able to provide reactive power control at either end of its connection. This service is currently of value to NEMMCO and is subject to separate commercial terms. However the DJV has not assigned any specific value to it in its application to the Commission.

The quantification and detailed consideration of the inter-regional market benefits able to be delivered by the Directlink asset is beyond the scope of this report.

PB Associates considers that the Directlink asset really only offer the controllable interregional flow capabilities and that claimed benefits of active and reactive capabilities are simply a restatement of these facilities. Further there will be additional tradeoffs between the extent of market benefits that can be provided by inter-regional flow facilitation where network support services are also required to be provided.

It could be argued that the increased security and stability are in fact captured by the increased capacity provided by Directlink. However PB Associates believes that there have been a number of technical papers produced which promote enhancements to system stability provided by HVDC Light® installations such as the Directlink asset. A detailed system study would be required to validate any claims of stability improvement benefits and any mutual exclusivity in providing such benefits as well as the other technical services claimed. Such analysis is beyond the scope of this report and the benefits are neither quantified nor submitted for inclusion in the market benefits test by the DJV and, as such, are not considered in the application of the Regulatory Test.

2.4 RELIABILITY AUGMENTATION DEFERRAL

The potential for the Directlink asset to defer reliability augmentations is considered on a pre-contingent basis. Pre-contingent flows are defined in Section 2.2 of the BRW report[9]) and refer to flows that are available for extended periods of time to ensure that network

[9] Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 2.2, page 7.

elements are not over-loaded and supply is maintained for critical contingency events on a sustained basis.

In their original submission the DJV had considered a post-contingent scenario (a scenario where additional control systems and equipment is installed to provide network support for a broader range of network outage contingencies) as the base case but the revised submission contemplates only the pre-contingent benefits provided by the Directlink asset.

Under medium load growth scenarios the Directlink asset is claimed to offer the following reliability augmentation deferral benefits on a pre-contingent basis:

2.4.1 Queensland (Powerlink) Deferral

From the summer of 2005/06, the 2005/06 Greenbank Molendinar 275 kV transmission line and substation augmentation[10][11][12] will be deferred by 1 year.

Powerlink supports the DJV's claim in this respect and has in fact contracted Directlink to provide network support for the 2005/06 summer period. As part of meeting this contractual requirement the DJV will need to enhance the existing emergency tripping scheme associated with the Directlink asset.

2.4.2 NSW (TransGrid) Deferral

The DJV claims that from the winter of 2006 the proposed (TransGrid) Dumaresq to Lismore 330kV transmission line[13][14] will be deferred by 11 years.

TransGrid have indicated that under their present planning the Dumaresq to Lismore line would not be required until at least 2007/08 or 2008/09. They have also indicated that a number of variables will impact this timing including the planned upgrading of the Armidale to Koolkhan 132 kV line (line 966) and the connection of biomass generation in the Lismore area. (see further in sections 2.9 and 3.8). TransGrid have also indicated that they have not carried out exhaustive modelling associated with the timing of the 330 kV asset and would only do so closer to the anticipated requirement time and would be impacted by the timing of other proposed augmentation works in the Mid North Coast and North Coast regions that are not impacted by Directlink.

Deferral of this augmentation is a major factor in this report and is covered in detail in section 3.

2.4.3 Deferrals in the Murraylink Regulated Application

In the case of the Murraylink application, the application refers to transmission deferrals in the Riverland area in South Australia, deferring the need for voltage support until 2007-08 and for thermal upgrades until 2012/13. The latest ESIPC annual planning report (dated June 2004) does not indicate that any voltage related augmentations are planned in the Riverland region prior to 2007-08 or that any thermal related augmentations are planned prior to 2012/13. Murraylink has, however, only been regulated for just over twelve months, so PB Associates considers that it is too early to be definitive as to

10 Powerlink, *Annual Planning Statement 2004*, June 2004.
11 Powerlink/Energex, *Application Notice Proposed New Large Network Asset – Gold Coast and Tweed Areas*, August 2003.
12 Powerlink/Energex, *Gold Coast Tweed Final Report*, 6 July 2004.
13 TransGrid, *Annual Planning Statement 2004*, June 2004.
14 Transgrid/Country Energy, *Emerging Transmission Network Limitations on the New South Wales Far North Coast,* August 2003.

whether the deferrals identified in the Murraylink application are reasonable in retrospect. It is important in developing regulation for Directlink and other potential regulated network assets that the revenues are linked to the services delivered over time. A critical lesson from the Murraylink review is that where deferral or other benefits are attributed to the asset that these deferrals are actually achieved.

2.5 LOAD GROWTH ASSUMPTIONS

BRW has indicated that they have used the TNSP (TransGrid and Powerlink) 2003 Annual Planning statements as the basis for their load growth projections up until 2012/13. Annual load growth projections of 25 MW per annum for the Gold Coast Tweed area and 15 MW per annum for the Far North Coast of NSW area have then been applied.

PB Associates has made a comparison with the information in the 2004 Annual Planning Reports and BRW's projections and the load forecasts are comparable. Powerlink's 2004 Annual Planning Statement has suggested that the anticipated average increase in South East Qld demand of approximately 170MW (5%) p.a. over the next five years. These growth rates are slightly higher for the medium and low growth scenarios and slightly lower for the high growth scenario compared to the Powerlink 2003 Annual Planning Report. In addition the revised energy growth rates in QLD in the 2004 Annual Planning Report are slightly higher over the long term than in the previous forecast. However, peak demand forecast growth rates have increased significantly – especially those for the next three years.

As a result of this assessment PB Associates believes that the BRW high growth scenario may be more applicable for consideration of the first tranche of deferrals identified for QLD in the BRW report.

TransGrid has indicated that growth in the Far North Coast area has averaged slightly less than 4% over recent years. Country Energy is predicting load growth of just over 3% in the far North Coast region in the short term which is slightly higher than that incorporated in the BRW report (which is based around 2.5% load growth). The use of a lower growth rate tends to enhance the longevity of deferral benefits of a particular project.

Load growth projections by all parties (BRW, TransGrid and Country Energy) do not factor in the potential for significant new local generation facilities, which could significantly impact the timing of the 330 kV asset requirement (refer comments in section 2.9).

2.6 CONSTRAINT ANALYSIS

The BRW report has identified a number of emerging constraints in the Gold Coast/Tweed and Far North Coast Regions relating to the adequacy of the networks to cope with future projected load growth and the ability to facilitate the use of Directlink to be used to defer proposed network augmentation projects.

While PB Associates believes that BRW have appropriately identified the constraints in their report it is not clear that the TEUS report has modelled these constraints adequately. However, the TEUS analysis assesses the market benefits of the Directlink asset which is beyond the scope of PB Associates review.

The constraints identified are discussed below:

2.6.1 Queensland

From 2005/06 onwards the BRW report identifies the following constraints in Queensland:

- Loss of Mudgeeraba – Broadbeach 110 kV line 779 or 780 lines will exceed continuous but not emergency rating of the other line.
- Loss of Swanbank - Mudgeeraba 275 kV line 805. Under certain loading conditions the voltages to Gold Coast would be outside acceptable limits and the load above the emergency ratings of line 704.
- Loss of Swanbank – Mudgeeraba/Molendinar line 806. Line 704 would be above its emergency rating and the Gold Coast voltage would be outside of acceptable limits.

PB Associates agrees with these main constraints identified by BRW. Presently, the maximum power transfer across this grid section is limited by the occurrence of unstable voltage levels during winter and potential 275kV and 110kV thermal overloads and unstable voltage levels during summer. The most critical contingency is an outage of a 275kV transmission line between Swanbank and Mudgeeraba (Line 806).

The present equation for the Gold Coast constraint limit with the Swanbank – Mudgeeraba contingency is shown in Figure 1 below.

Figure 2-1- Gold Coast Constraint Equation[15]

Measured Variable	Coefficient Swanbank-Mudgeeraba Contingency
Constant Term (Intercept)	455.32
Number of Wivenhoe units on-line	5.9757
Number of Swanbank B units on-line	5.5384
Number of Swanbank E units on-line	18.4529
DirectLink power transfer at Mullimbimby (MW positive is into Qld)	-0.7469
DirectLink reactive power at Bungalora (MVAr positive is into Qld)	0.3563
Number of Palmwoods 110kV Cap Banks available	1.6243
Number of South Pine 275kV Cap Banks available	4.6178
Number of South Pine 110kV Cap Banks available	2.6021
Number of Rocklea 110kV Cap Banks available	3.4356
Number of Belmont 275kV Cap Banks available	7.8884
Number of Belmont 110kV Cap Banks available	5.0531
Number of Blackwall 275kV Cap Banks available	7.8316
Number of Mudgeeraba 275kV Cap Banks available	22.3571
Number of Mudgeeraba 110kV Cap Banks available	12.6893
Number of Loganlea 110kV Cap Banks available	5.8353
Number of Mt England 275kV Cap Banks available	3.0938

The amount of load able to be supported increases with the northerly flow on Directlink but not proportionally. Figure 2-1 shows that the Directlink Power transfer at Mullumbimby has a co-efficient of -0.7469 and as such an increase of 1 MW from Directlink will result in a total load support increase of only (1-0.7469) MW. So, in effect only 35% of Directlink's capacity will go towards actually increasing load supplied into the Gold Coast region itself.

[15] Source: Powerlink, *2004 Annual Planning Report*, June 2004

Powerlink has already contracted Directlink to provide network support services for 2005/2006.

Deferral of the 330 kV Dumaresq to Lismore line in NSW relies, to some extent, on the timely implementation of Powerlink's proposed augmentation program after 2005, as this is necessary to provide sufficient available capacity to support southward flows on Directlink. However, PB Associates has concerns that Powerlink may not be able to construct the additional third 110kV transmission line into Terranora substation within its stated timeframes, or even at all, due to the need to obtain planning and environmental approvals for that section of the route within NSW. This is discussed further in Section 2.7 of this report but would mean that the ability for Directlink to defer TransGrid's augmentations could be limited by the ratings of the existing 110 kV lines.

2.6.2 NSW

BRW have identified the following constraint contingencies/limits associated with the northern NSW network from winter 2006 onwards (apart from Directlink's own limits):

- Loss of Armidale – Coffs Harbour 330 kV line 89 formed by turning the Armidale – Lismore line in to Coffs Harbour, results in overloads and depressed voltages to Lower North Coast.
- Loss of either Mudgeeraba - Terranora 110 kV line 757 or 758 – results in other line being overloaded.
- Voltage stability limits in the Gold Coast area.
- Swanbank – Mudgeeraba/ Molendinar 275 kV.
- Loss of Muswellbrook – Tamworth 330 kV line 88.
- Loss of Liddell- Muswellbrook 330 kV line 83.
- Loss of Liddell-Tamworth 330 kV line 84.
- Loss of Armidale -Tamworth 330 kV line 85.
- Loss of Armidale -Tamworth 330 kV line 86.

The latter 5 limits are dependent on the flow on QNI at particular points in time. In fact they constrain the total northward transfer capability of the combined QNI and Directlink assets.

PB Associates agrees with the major constraint limits identified by BRW. The principal intra-regional constraint relates to unacceptably low voltages on outage of the 330 kV line from Armidale to Lismore (via Coffs Harbour) at times of high system load in summer or winter.

The other thermal rating limitation is the rating of the Armidale to Koolkhan 132 kV 966 line (the oldest 132 kV line in the area) being exceeded following an outage of the 330 kV lines from Armidale to Lismore at times of high load. TransGrid has advised that it is uprating this line as discussed in section 3.2.

2.6.3 NEM Historical Directlink Constraints

Historical analysis of the operation of the Directlink asset identifies the following market based constraints that have impacted on the ability of Directlink to transfer power between the regions.

Northward flow – NSW to QLD

The most frequent constraint has been the NQDL_ROC constraint that limits changes in flow on Directlink to 80MW per dispatch interval, in order to manage the voltage impacts on the surrounding network that result from rapid changes in power flows on Directlink. A higher export capability will usually be possible over a number of dispatch intervals.

Southward Flow – QLD to NSW

The most frequent constraint is the QNDL_ROC constraint that limits changes in flow on Directlink to 80MW per dispatch interval, in order to manage the voltage impacts on the surrounding network that result from rapid changes in power flows on Directlink. Once again a higher export capability would usually be possible over a number of dispatch intervals.

The above constraints will impact on the manner in which Directlink can be operated to provide inter-regional flow benefits and may also limit the way in which Directlink can be operated in order to provide pre and post contingent support for the 330 kV Lismore Armidale line. There are clearly tradeoffs that will exist between providing the full extent of market benefits and also pre and post contingent support.

2.7 ENVIRONMENTAL ISSUES

PB Associates has identified that environmental issues may delay or potentially preclude altogether the installation of the third 110kV line being constructed into Terranora substation from Mudgeeraba. This may impact on the longer term capability of Directlink to provide network support to the NSW system. Specific environmental issues associated with credible Alternatives are discussed in Section 3 when considering each of the Alternatives.

The DJV has previously been required to implement a number of noise mitigation measures in relation to the converter station installations, however PB Associates is not aware of any additional environmental issues associated with the present Directlink asset configuration.

2.8 POTENTIAL NON-NETWORK SOLUTIONS

The Directlink asset represents a network based solution to providing network support and other technical services to the National Electricity Market.

There is a requirement for TNSPs to examine whether non-network solutions can provide network support services. The obvious solutions fitting into this category are local generation and demand side management initiatives.

As part of the DJV submission, BRW has examined the potential for embedded generation and demand management to provide a reliable alternative to the Directlink asset[16]. In their submission this was rejected as not being a reasonable alternative for the purposes of applying the regulatory test.

However PB Associates is aware of two major generation projects in the Lismore/Tweed Heads region currently approaching financial closure that have a high probability of deferring the requirement for the 330 kV Dumaresq to Lismore line. While not providing an additional alternative such generation may affect the timing of constraints being addressed by the Alternatives already identified. The details of these projects are discussed in section 3.2 to the extent possible noting the confidential nature of discussions held with the generation proponents.

The proposed generation is anticipated to be base loaded, and to have a reasonable level of availability with supplementary fuel to the primary seasonal bagasse fuel being sourced. Outages could be scheduled outside of peak network demand periods if required. PB Associates has factored these projects into its considerations of deferral periods associated with Alternative 5 as they are well advanced and have a high probability of proceeding.

PB Associates is aware of a number of wind generation proposals in the Glen Innes area (also referenced in the TransGrid 2004 Annual Planning Report), which could provide network support to the Northern NSW transmission network at times. These projects are only in the preliminary development phase and because of the relatively low availability from wind based generation are not considered to be reliable sources of network support. In any case they are not located in such a position to assist the supply situation in the North Coast and Gold Coast regions.

PB Associates is not aware of any demand management projects that would impact on the Commission's considerations in relation to the DJV application. It is noted, however, that if significant government policy initiatives were introduced which gave higher financial incentives for demand management this may impact on future load requirements. Like many other factors, this is highly speculative and difficult to incorporate into this review.

16 Report "Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, section 3.8.

3. SELECTION OF THE MOST EFFICIENT INVESTMENT

This section reviews a number of alternative projects and assesses the extent to which each alternative represents a reasonable substitute for Directlink for the purposes of the Regulatory Test.

3.1 APPROACH TO THE ASSESSMENT OF THE ALTERNATIVES

New regulated investments should be premised on delivering maximum benefits to the market. As identified in the Commission's regulatory test, this either relates to least cost investments for supplying requisite levels of supply reliability, or maximum net benefits for non-reliability based investments.[17]. This comprises two key steps; establishing the need for the investment and determining if it is justifiable in the light of any emerging network limitations, and selection of the most efficient investment solution by exploring the range of feasible alternatives available.

The work in this section focuses on an examination of the alternative projects as presented by the Directlink Joint Venture (DJV), as PB Associates has formed the view that the DJV's consultant, BRW, has correctly identified all the technically plausible alternatives. Our analysis and comments associated with each alternative project are based, where appropriate, on the following structure:

- technical specification – is it technically viable? How will it work? What service does it set out to provide?
- solution capability – to what extent does it provide power transfer capability and under what conditions? How does it compare with the 'base-case' solution of pre-contingent Directlink?
- deferment opportunities – to what extent, if at all does the alternative defer investment which is required to meet statutory obligations?
- additional benefits – are there any additional benefits which can be quantified? Does it provide any valuable ancillary services or environmental advantages or benefits?
- cost assessment – are the costs associated with each of the identified alternative projects reasonable and appropriate?

The comparison of alternatives is based on a conversion date of 1 July 2005. All costs and benefits are assessed in relation to that date.

3.1.1 Interest during construction (IDC's) and contingencies

PB Associates has reviewed the inclusion of IDC's and contingency allowances by DJV in its application. For the alternatives which are being assumed as proxies for the Directlink assets, the construction and commissioning dates are assumed to be the same, ie 1 July 2005. In this instance, since there is no delay between conversion date (becoming a regulated asset) and revenue derivation, there is no requirement in our view to include IDC's. To include IDC's for estimating the present value of investments for proposed alternatives to Directlink would, in our view result in double counting, as the cost of capital is implicit in the discount rate.

17 'Regulatory test for New Interconnectors and Network Augmentations', ACCC, 15 December 1999.

In the case of contingencies, these are costs in addition to those estimated based on individual components and therefore reflect a measure of inefficiency which is not consistent with the requirements of the National Electricity Code. The costs assumed by PB Associates in the evaluation of alternatives, and also assumed by BRW in its analysis for the DJV, include estimated actual costs and therefore do not require an additional contingency allowance.

3.1.2 Alternative 5 as the "Reference Case"

In assessing the network benefits offered by Directlink it is necessary to relate this to the supply and network requirements of the region. The north eastern region of NSW has good load growth and is forecast to become summer peak demand driven by 2012. In order to maintain supply security to this region TransGrid has identified that Alternative 5 augmentations (330kV line from Dumaresq to Lismore) will be required at some stage over the next 10 years.

PB Associates has reviewed this position and agrees that these augmentations are the most likely long term solution. The DJV submission also acknowledges that these works are likely. The more difficult questions relate to the exact timing of the work and the eventual costs of those augmentations. In this report, therefore, PB Associates has referenced the other alternatives to Alt 5 in order to assess the deferral impacts that are anticipated from each alternative. For this reason Alternative 5 is presented first, not strictly as an alternative, since it provides considerably greater capacity than that offered by Directlink, but rather as a reference for those alternatives comparable to Directlink to assess the relative deferral impacts.

It is also noted that Queensland augmentations deferrals are the subject of a separate commercial agreement between Powerlink and DJV covering the period up to the completion of these works and these arrangements may remain outside the regulated revenues defined by the Commission.

3.2 ALTERNATIVE 5 – "REFERENCE CASE" STATE-BASED AUGMENTATIONS

This Alternative is the only foreseeable option identified by TransGrid that will provide secure electricity supply to the region in the medium and longer term. All other Alternatives defer some, or all, of these augmentations for varying periods but cannot (in isolation) provide the requisite levels of security to cater for growth in both electricity demand and customer numbers in the Gold Coast/Tweed region in the medium to long term. For this reason PB Associates consider Alternative 5 to be an extremely important element of the Directlink review.

In this section we provide an overview of the DJV definition of Alternative 5 before setting out PB Associates view of the augmentations which would be required in the event of no Directlink service. Our view follows meetings and discussions with key parties including TransGrid, Powerlink, Energex and Country Energy. The section provides details of the PB Associates' view of the required State based augmentations. The financial impact of any variations to Alternative 5 in terms of the ability of the other Alternatives to defer the state-based augmentations – are quantified in each respective Alternative section.

In formulating its views of the State-based augmentations which would be necessary in the absence of Directlink, PB Associates has spent time with DJV's consultants, BRW, to review the modelling which has been undertaken and to test, what PB Associates believes to be, a number of key assumptions.

3.2.1 DJV re-submission

The DJV Revised application [18] includes a number of changes to the definition of Alternative 5. These, essentially, represent an alignment with the views of Powerlink and TransGrid with regard to the nature and timing of the state based augmentations – following DJV's further detailed discussions with the two transmission network service providers.

3.2.2 The DJV technical specification and description of the service offered

In this section we set out the applicant's (DJV) definition of the State-based augmentation which would be required in the absence of the Directlink service.

3.2.2.1 Description of Alternative 5

Alternative 5 comprises reliability-driven network augmentation in both Queensland and New South Wales. It represents DJV's view of the network investments which would need to be made by TransGrid and Powerlink to alleviate system constraints which would occur in the Gold Coast (QLD) and the far north coast of NSW in the absence of the Directlink facility over the planning period.

BRW assumed that the QLD component of Alternative 5 – consisting of the new 275kV Greenbank switchyard and the new double circuit 275kv line linking the new Greenbank switchyard with the existing Molendinar substation – would be commissioned by 2005.

BRW has determined that the NSW component of Alternative 5 consists of a new 330kV AC line from Dumaresq substation to Lismore substation to provide active and reactive support to the far north eastern corner of the state. The line would follow the route of the existing 132kV line from Lismore to Tenterfield and then along a new corridor to Dumaresq. BRW has assumed that this component of Alternative 5 would be required by 2006/07.

3.2.2.2 Active power flow capability and inter-regional flows

This alternative does not connect the Queensland and NSW regions directly and therefore cannot facilitate inter-regional flows. Hence no additional active power can be transferred between the regions, as under this option QNI remains the only interconnector between NSW and Queensland.

However system losses would be reduced under this scenario due to the construction and augmentation of network assets in both regions.

3.2.2.3 Reactive power flow capability and voltage control

The number of static capacitors required for steady state voltage control at load centres in NSW is substantially reduced under this option compared to Alternative 0 due to line charging and lower reactive losses from either the new or augmented transmission assets.

3.2.2.4 Network support capability

Local support is provided with augmented connection between the local network and the state based generators. This alternative does not provide network support across the two

[18] The DJV's Revised application was submitted to the Commission in September 2004 and incorporated material changes to the technical capabilities of Directlink.

regions. Augmentations are required in each state to address local network constraints but all power is sourced at the regional price and there are no counter price flows.

3.2.2.5 Statutory obligations

These obligations relate primarily to the TNSP's licence conditions which state *"the transmission entity must plan and develop its transmission grid in accordance with **good electricity industry practice** such that … the power transfer available through the power system will be adequate **to supply the forecast peak demand during the most critical single network element outage"***

These obligations can be met if the Service Providers plan network augmentations to deliver N–1 reliability standards in a timely manner. PB Associates has no reason to believe that the network augmentations planned by both TNSPs and their commissioning timetable would not deliver the statutory reliability standards in accordance with their licence conditions.

The details of Alternative 5 as proposed in the revised Directlink Joint Venture (DJV) - Application for Conversion, are contained in the BRW report. The augmentations proposed by the DJV are similar to those proposed by both Powerlink and TransGrid to alleviate network constraints that will emerge in the Gold Coast and northern NSW in 2005 and 2006.

In Queensland the DVJ have modelled a new 275 kV AC line linking a new Greenbank switchyard with Molendinar substation. The new line would be constructed between Greenbank and Maudsland with an existing circuit between Maudsland and Molendinar forming the remaining part of the line. The new 275kV switchyard would include switchgear to cut into the existing 275kV lines that pass through the site and a new 120MVAr capacitor bank. A new 275kV/110kV transformer would be installed at Molendinar to supply the Energex network at approximately the same time.

These augmentations are required to provide active and reactive power support to the Gold Coast network to relieve the local thermal and voltage constraints. The augmentations are required to provide continuity of supply during the most critical credible contingency, which is the loss of the existing Swanbank to Mudgeeraba/Molendinar 275kV teed line (Line 806).

The NSW augmentations proposed by the DJV consisted of a new 330kV AC line linking Dumaresq substation with Lismore substation to provide active and reactive power support to the far north NSW network to relieve emerging thermal and voltage constraints. This new line would provide continuity of supply during the most critical credible contingency which is the loss of the existing Armidale to Lismore 330kV line (Line 89) which by that time would also be supplying the new Coffs Harbour 330/132kV substation.

3.2.3 Deferment opportunities

As stated in section 3.1.2, Alternative 5 effectively represents the 'reference case'[19]. A proportion of the benefits associated with all of the other options is derived from the extent to which they can defer the network augmentations. All other Alternatives were assessed in terms of their ability to defer the augmentations proposed in Alternative 5 and the prospects for the provision of other services.

[19] Note that this is not the 'base-case' as defined by the DJV.

3.2.4 PB Associates comments on Alternative 5

In this section we offer the views of PB Associates on the state-based augmentations which we believe will at some stage be required in the absence of Directlink or any of the defined Alternatives.

The state based augmentations proposed by the DJV have been examined in detail and discussed with both Powerlink and TransGrid.

3.2.4.1 Queensland network augmentations

Whilst PB Associates recognises that DJV's revised application places less emphasis on the value of Directlink in its ability to defer network augmentation in Queensland beyond 2005[20], we provide below, PB Associates' view on some aspects of the Queensland elements of Alternative 5.

In its original application, DJV proposed a new single 275kV line linking a new Greenbank substation with Molendinar substation. Under DJV's proposal, a new line would be constructed between Greenbank and Maudsland with an existing circuit between Maudsland and Molendinar forming the remaining part of the line.

BRW assumed that the QLD component of Alternative 5 – consisting of the new 275kV Greenbank switchyard and the new double circuit 275kv line linking the new Greenbank switchyard with the existing Molendinar substation – would be commissioned by 2005. The capital cost for this work has been estimated by Powerlink to be $48.9M (2004 dollars) excluding IDC. Discussions with Powerlink also indicated that this estimate did not include the easement costs as these easements had been acquired many years earlier.

PB Associates has some concerns associated with this initial proposal. In discussions with Powerlink information was provided concerning a Supreme Court Judgment relating to the use of the existing easement for the construction of the new 275kV transmission line[21]. This Supreme Court Ruling substantially impacts on the DJV proposals in so far as the teed line from Maudsland to Molendinar substation cannot remain in service and has to be extended back to the new Greenbank substation in conjunction with the construction of the new line proposed from Greenbank to Molendinar.

PB Associates notes that the revised submission now aligns with Powerlink's views in this regard and specifies the construction of a new double circuit 275kV line linking the new Greenbank switchyard with the existing Molendinar substation.

3.2.4.2 New South Wales network augmentations

In the revised DJV submission the majority of the augmentation deferral value ascribed to Directlink is associated with network investment which is assumed to be required in New South Wales (NSW) over TransGrid's planning time horizon. The definition of the NSW augmentation works is, therefore, very important in the valuation of Directlink and its Alternatives.

In its most recent Annual Planning report TransGrid describe the anticipated network constraints associated with maintaining secure supplies to the Lismore Area. The

[20] The present one year contract between DJV and Powerlink for network support services expires in October 2006.

[21] The ruling does not allow Powerlink to construct one circuit of the double circuit transmission line in the first instance and construct the second circuit at a later date; as both circuits have to be energized in order to minimise electro-magnetic fields (EMF) along the route.

capacity of the 132kV system in the far north coast of NSW is constrained, primarily, in two key areas. These are:

- the thermal rating of the 966 Armidale to Koolkhan 132kV line. This becomes a binding constraint in the event of an outage of the Armidale – Lismore 330kV supply[22]; and

- the prospect of unacceptably low voltages in the Coffs Harbour/Koolkhan area in event of the same outage (i.e. the Armidale – Lismore 330kV line). TransGrid propose to install additional capacitors at Koolkhan and Nambucca to assist in this regard[23].

TransGrid set out a number of potential options for overcoming both of these constraints[24]. These include:

- uprating of the 966 Armidale – Koolkhan 132kV line[25];

- construction of an additional 330kV line from Dumaresq to Lismore;

- use of local generation for network support;

- use of Directlink;

- construction of additional 132kV lines; and

- demand management

The network augmentation deferral value of Directlink in the DJV application is (primarily) based on the solution being the construction of a new 330kV line from Dumaresq to Lismore. This would link the Dumaresq and Lismore substation to provide active and reactive power support to the far north eastern New South Wales network to relieve emerging 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).

These potential solutions for the support of the Lismore area, as outlined by TransGrid, are not, however, mutually exclusive. Moreover, in discussions with TransGrid (and others), it has become apparent to PB Associates that at least two of the options outlined above will be proceeding ahead of construction of the Dumaresq to Lismore 330 kV line regardless of Directlink.

PB Associates are of the view that this modifies the definition of Alternative 5 – principally, by changing the timing of the need for the anticipated new Dumaresq to Lismore 330kV line.

PB Associates is also aware of network limitation in the NSW mid coast area particularly in the Port Macquarie on Coffs Harbour region. TransGrid is addressing these constraints with both committed and proposed system augmentations. A new 330/132kV substation at Coffs Harbour is planned to be commissioned by winter 2006. The second 132kV line between Kempsey and Port Macquarie is planned for commissioning by 2005/06 which will eventually form part of a new 330kV connection from Armidale to Port Macquarie and the construction of a new 330/132kV substation in Port Macquarie by

[22] TransGrid expect this constraint to be reached by the summer of 2005/06.

[23] Without the additional capacitors, TransGrid expect this voltage constraint to be reached by winter 2006 and by winter 2007 if the capacitor installation is completed.

[24] TransGrid Annual Planning Report 2004, Section 6.5.2, page 52.

[25] This would not overcome the voltage constraint.

2008/09. PB Associates agrees with comments made by TransGrid and BRW that Directlink would not be able to assist in any significant way to defer these projects.

3.2.4.3 *Construction of a new Dumaresq to Lismore 330kV line*

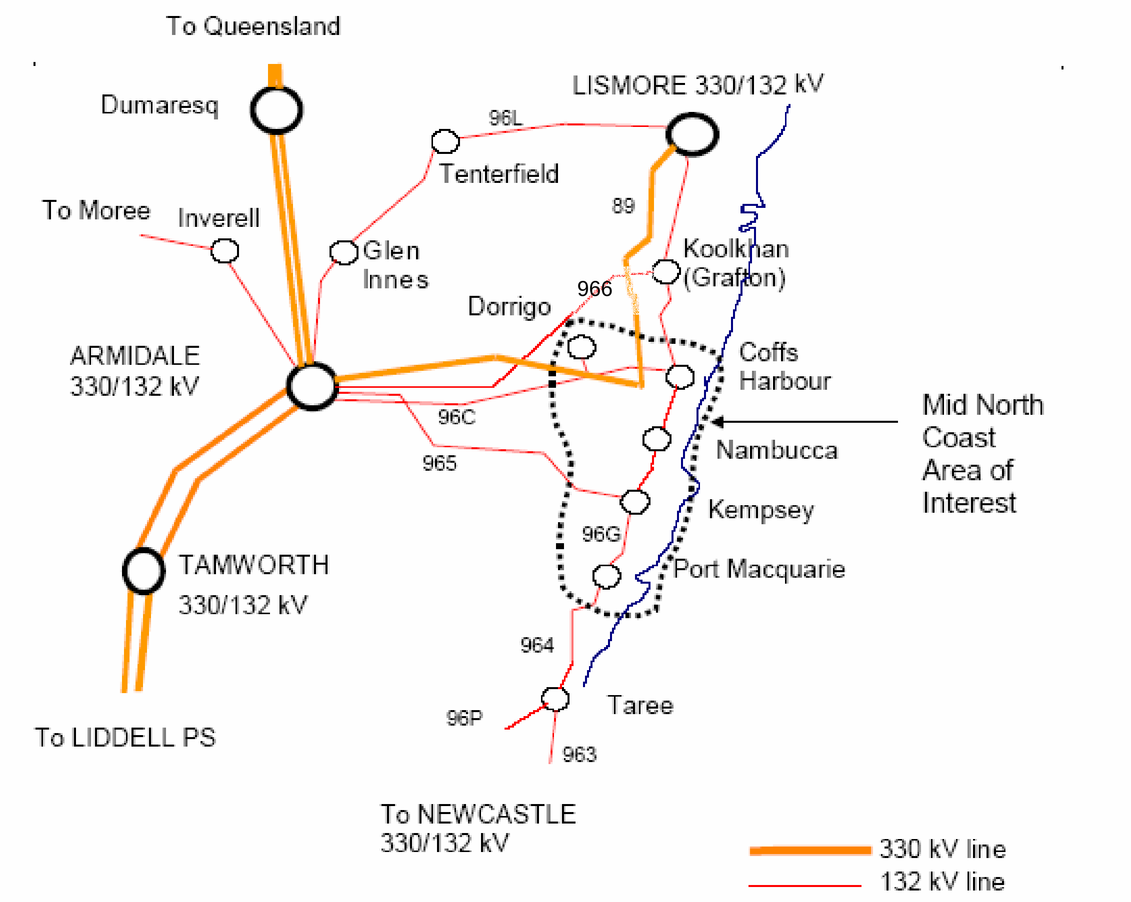
PB Associates has held meetings with both TransGrid and Delta Electricity which have resulted in the identification of specific projects which appear certain to proceed in the near term and which will affect the timing of the need for the proposed new Dumaresq to Lismore 330kV line.

Upgrading of the 132kV line 966

We refer to the network diagram in Figure 3-1.

TransGrid have advised that they will be upgrading the 132kV line between Armidale and Koolkhan (Line 966) and also installing additional capacitors at their Koolkhan, Lismore and Nambucca substations. Transmission line 966 will be upgraded in a similar fashion to the recent upgrade carried out on the 132kV Armidale to Kempsey (Line 965) and due to the construction, age and topographical similarities of these two lines, similar rating increases have been assumed by PB Associates. PB Associates are of the view that these upgrades could result in a similar sustained emergency rating of approximately 120MVA under worst case conditions.

Figure 3-1 - Far North Coast network



TransGrid/Country Energy, Development of electricity supply to the New South Wales Mid North Coast, Final Report October 2003

Proposed local generation

As part of the review process PB Associates held a meeting with Delta Electricity. PB Associates has been advised that 30MW bagasse generators will be installed and connected to Country Energy's distribution networks at the Broadwater and Condong sugar mills. Both projects are significantly advanced with financial close expected early December 2004.

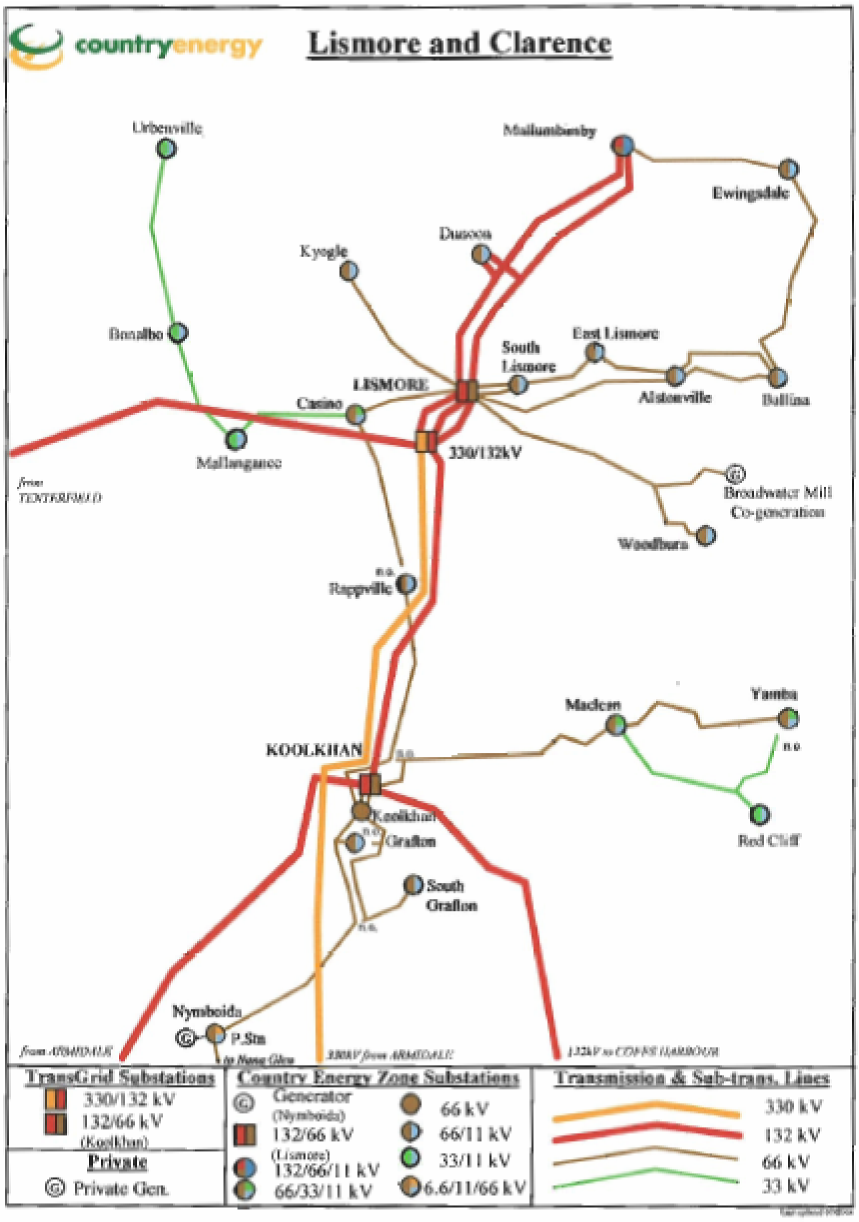
The additional generator at Broadwater Mill will be connected to Country Energy's 66kV network and will provide direct support to the Lismore 132/66kV substation. When operational, the generator will be capable of exporting 26.9MW during the crushing season, July to December each year, and 26.7MW during the non crushing season[26]. This new generator at Broadwater Mill is due to be commissioned in March 2007.

The generator will operate at base-load with an estimated annual availability of 95%. As an embedded generator the unit will be incentivised to operate at times of peak transmission system demand – by virtue of its ability to earn the commercial benefits associated with a reduction in Country Energy's liability for transmission use of system charges (TUoS).

The new generator to be installed at the Condong sugar mill is due to be commissioned in December 2007 and can export 23.6MW during the crushing season and 26MW during the non crushing season, January to June each year. PB Associates are not aware that the Condong generation will offer any network support benefits other than to possibly relieve the constraint on supply from the Queensland network for a short time around 2015/2016.

[26] The existing 8MW generator at Broadwater sugar mill supplies the mill's electrical load requirements.

Figure -3-2 - Location of the Broadwater Mill generator



[Extracted from the 2004 Country Energy Electricity System Development Review]

Timing associated with the need for the new Dumaresq to Lismore 330kV line

The timing of the requirement of the proposed Dumaresq to Lismore 330kV line is an important factor in the value placed on Directlink and its Alternatives as part of the DJV application.

In order to determine the effect of these projects on the deferment of the Dumaresq to Lismore 330kV transmission line PB Associates has used the information contained with the revised DJV conversion application[27] supplied in the BRW report attached to the

27 Directlink Joint Venture, Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC, 22 September 2004 (Appendix D, Section 4).

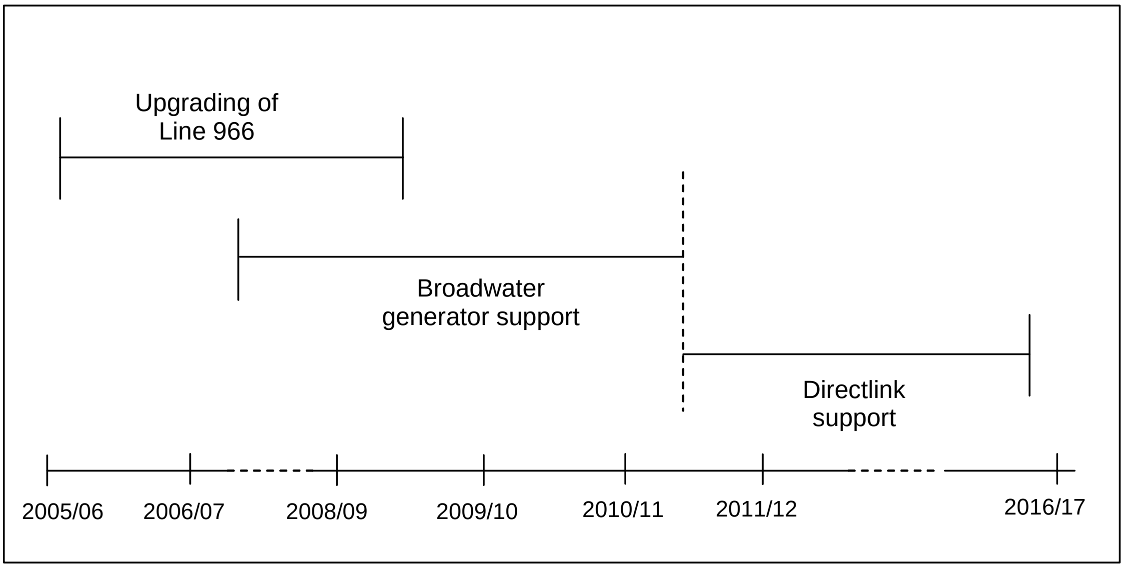
Directlink Joint Venture, Application for Conversion[28]. Specifically, the BRW modelling results associated with the loading on the Armidale to Koolkhan 132kV line (Line 966) and the voltage at Koolkhan – Tables 4.3.1(a) and 4.3.1(b) respectively – have been used to determine deferment periods.

PB Associates has determined that one of the consequences of increasing the thermal rating of Line 966 is to defer the need to construct the new 330kV line Dumaresq to Lismore until after 2008/09. The BRW modelling indicates that the post contingent load on Line 966, after the loss of the Armidale to Lismore 330kV, is well within the new thermal rating of the line. Table 4.3.1(a) in the BRW Report indicates that the post contingent loading on 966 over the period 2005/06 to 2008/9 does not exceed 110MW.

Table 4.3.1(b) indicates that voltage collapse at Koolkhan, from 2009/2010 onwards, becomes the limiting factor – rather than the thermal rating of either Line 966 or Line 977. Table 4.3.1(b) also indicates the amount of network support required to negate this constraint. At 2011/12 Table 4.3.1(b) of the BRW report indicates that 28MW is required to maintain acceptable voltage levels at the Koolkhan substation. The 30MW generator at the Broadwater sugar mill is scheduled to be commissioned by this date and is capable of exporting at least 26.7MW. Allowing a 0.95 availability factor for this generator and the fact that it will be incentivised to operate over peak periods. PB Associates has concluded that this generator ought to be able to defer the need to construct the 330kV Dumaresq to Lismore line from 2008/09 till after 2010/11.

The timeline associated with the need for the new Dumaresq to Lismore 330kV line is shown in Figure 3-3.

Figure 3-3 - Timeline showing the deferral of the Dumaresq to Lismore 330kV line



The prospect of a third overhead circuit into Terranora substation

The Terranora substation is located in one of the of the most environmentally sensitive areas of NSW and, combined with the ever increasing complexity of obtaining state and local government approvals, and community acceptance, PB Associates has reservations on the likelihood that this third feeder could be constructed to meet these time frames. Lead times for new transmission lines in NSW are now approximately five years so even

28 PB Associates has not undertaken any independent network modelling.

if the project was commenced immediately it is unlikely to be commissioned before 2009/2010.

PB Associates has concluded that it would be difficult to obtain approval to construct a third 110kV tower line through the Terranora residential area and landing on one of the most prominent hills in the area.

If this third 110kV line from Mudgeeraba to Terranora is not constructed and the peak load growth in the Tweed area has to be addressed by a combination of other initiatives then the ability of Directlink to defer construction of the new 330kV line from Dumaresq to Lismore will require re-evaluation. However, all modelling assumes the third line is in service before 2006/07.

The Energex Limited and Powerlink Queensland – Final Report, Coast and Tweed Areas dated July 2004 report indicates that depending on the loading on the existing two 110kV lines Mudgeeraba to Terranora an additional circuit may be required to be installed beyond 2008.

BRW state in their report of September 2004 that Country Energy have identified a thermal constraint on the Mudgeeraba to Terranora 110kV lines with a third line required to supply the Tweed area by 2006/07. On this basis BRW have assumed that this third line will be in service by 2006/07 which is at least one year earlier than Energex/Powerlink identified in their Final Report on the Gold Coast / Tweed areas.

Therefore if this additional line does not proceed or if it is delayed there will a substantial impact on Directlink which reduces its ability to provide network support to Northern NSW. PB Associates recommends that further modelling be undertaken to determine the Directlink deferral capabilities under this scenario. It is PB Associates view, however based on information in the BRW report, that Directlink may not be able to provide sufficient network support to northern NSW during 2007/08 and from 2011 to 2017 inclusive if this third line into Terranora or other potential alternatives are not commissioned prior to 2007/08. However, given that detailed planning has only been undertaken by TransGrid for ten years and that many uncertainties exist regarding other possible scenarios beyond this period, including the challenges of gaining approval to build the third line into Terranora, PB Associates recommends that the deferral benefits only be considered up until 2014/15.

3.2.4.4 PB Associates findings on the NSW augmentation element of Alternative 5

PB Associates are of the view that the combination of the upgrade of the proposed 132kV line between Armidale and Lismore (Line 966) and the commissioning of the additional Broadwater Mill generator will defer the need to construct the new Dumaresq to Lismore 330kV line until after 2010/2011. This is supported by statements made in the Powerlink Final Report[29]. We present the following extract from that report:

> *"…that northern NSW supply requirements are addressed through a modelled arrangement for network support from either Directlink or embedded generation from mid 2006 onwards. It is assumed that this is capable of addressing the Far North Coast of NSW supply requirements for six years, with network augmentation being required in NSW by 2012".*

This would seem to support the view that (alternative) network support can defer the construction of the new Dumaresq to Lismore 330kV line until 2012.

Both Table 4.3.1(a) and 4.3.1(b) in the BRW report indicate that voltage collapse occurs after 2016/17 irrespective of any network support that can be provided by either

29 Powerlink Final report, Proposed New Large Network Asset – Gold Coast Tweed Areas, 6 July 2004.

Alternatives 0, 1 or 2. PB Associates has assumed that this voltage collapse is due to constraints in the Queensland Powerlink network and have also assumed that the Condong sugar mill 30MW generator, which is connected to the 66kV feeder from Terranora to Murwillumbah, may alleviate this constraint for a further year allowing Directlink to defer the need to construct the 330kV Dumaresq to Lismore line until 2017/18. This assumption is again based on the BRW system modelling which incorporates the third Mudgeeraba to Terranora 110kV feeder commissioned in 2006/07.

3.2.4.5 Assessment of estimated costs

PB Associates has reviewed the estimated capital and ongoing operation and maintenance cost provided by BRW for Alternative 5, which only include the NSW augmentations, and concluded that efficient costs are as follows:

Table 3-1 – Capital Construction Costs for Alternative 5

Project Component	Total Cost $m
Construction Contract	$83.1m
Spares	$1.7m
TransGrid Costs	$10.1m
Easements	$35.0m
TOTAL	**$129.9m**

Annual incremental operation and maintenance costs (2% of construction contract costs as indicated by TransGrid during discussions) are expected to be $0.548m based on the assumption that this new line replaces an existing 132kV line for approximately 66% of its length.

In addition to the NSW augmentation costs, PB Associates has also reviewed the capital and operating costs relating to the Queensland augmentations. Capital costs advised by Powerlink in their Final Report[30] are estimated at $48.9m excluding IDC's and contingencies. This figure also excludes associated easement costs which Powerlink have already acquired and hence will not be deferred. PB Associates has estimated operating and maintenance costs for these projects to be $0.98m per annum based on an assumed level of 2% of construction costs.

3.3 ALTERNATIVE 0 – DIRECTLINK WITH PRE-CONTINGENT SUPPORT (BASE CASE)

This alternative is described as the existing Directlink project with some modifications to the existing protection and control systems to Code standards.

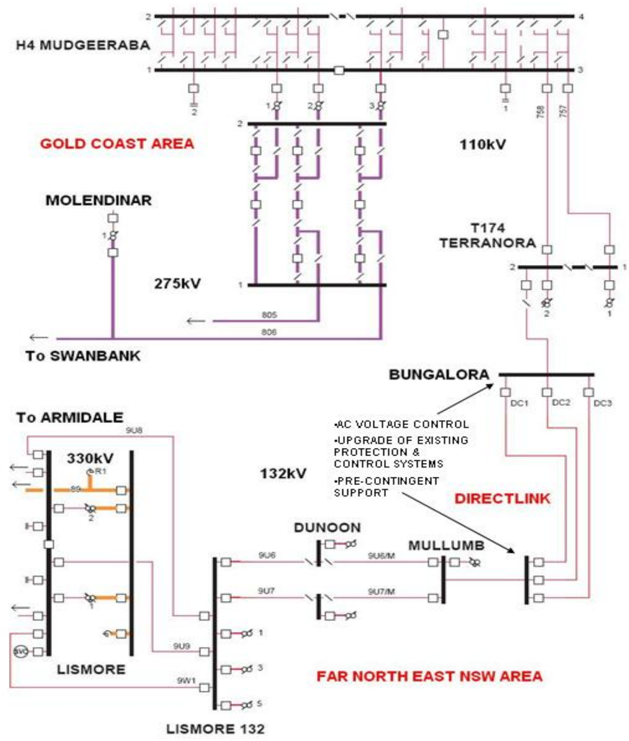
3.3.1 Technical specification and description of the service offered

This alternative involves the "as installed" Directlink facility, comprising three parallel 60MW HVDC Light® links, with converter stations at Mullumbimby and Bungalora connected by underground HVDC cables and 110kV HVAC cable between Bungalora and Terranora, with pre-contingent support capability including the upgrade of the existing protection and control system to Code standards.

Alternative 0 is shown schematically in Figure 1. The DJV submission and the BRW report does not provide details of the protection and control system upgrades required.

[30] Powerlink Final report, Proposed New Large Network Asset – Gold Coast Tweed Areas, 6 July 2004.

Figure 3-4 - Alternative 0 schematic diagram



3.3.2 Solution capability

The DJV has identified the network services provided by alternative 0. PB Associates provides the following comments.

3.3.2.1 Active Power Flow Capability

The HVDC Light® converters used in alternative 0 allow the precise control of active power flows, in both directions, between the northern NSW Coastal and Gold Coast regions. The active power flows are independent of generator scheduling and demands on either side of the link, unlike an AC interconnection. These flows can potentially be used to provide a number of support services to the AC networks, including loss minimisation, optimisation of network utilisation for reliability gains and wholesale market support.

3.3.2.2 Reactive Power Flow Capability and Voltage Control

The HVDC Light® converters can supply or absorb reactive power independently of the active power flows, but within the bounds of the published PQ curve for Directlink. This is a significant benefit of the Voltage Source Conversion (VSC) technology used by HVDC Light®. In regard to reactive power the quantum and either the supply / absorption capability of Directlink can be controlled manually at either converter station.

The facility can be used to also control the AC voltage independently at either end of Directlink (i.e. at Bungalora or Mullumbimby). During a visit to the Bungalora site on 29 June 2004, PB Associates were advised that the AC voltage control function is operated such that one converter at Bungalora is in "AC Voltage Control" mode, while the other two converters are in "Reactive Power Control" mode. This means that one converter is controlling the voltage within the reactive power limits of that single converter, while substantial reactive power requirements are manually adjusted by the operator on the other two converters. There is a concern, however, in so far as the level of AC voltage control for two thirds of the reactive power capability of the facility is not, at this stage, equivalent to an SVC as stated in the BRW report[31]. PB Associates has not been advised when the Bungalora converters will be in a position to provide the full level of AC voltage control. PB Associates understands that the improvement of the AC voltage control, to the degree that it is equivalent to an SVC, is included in the upgrade works proposed by the DJV.

3.3.2.3 Network Support Capability

The BRW report identifies that Alternative 0 connects into different parts of the transmission networks than the parallel AC interconnector, QNI. Although some interdependencies are identified between the AC interconnector and alternative 0, BRW contends that Alternative 0 could provide network support services to these local networks and possibly defer network reliability augmentations in these networks. PB Associates notes however that such network support services will be limited to pre-contingent network support services (as defined in Section 2.2 of the BRW report[32]) in the case of Alternative 0 and may be limited by constraints in the AC transmission network.

3.3.2.4 Facilitation of Inter-Regional Flows

The BRW report identifies that Alternative 0 allows better utilisation of available generation capacity throughout the NEM, and can create economic benefits in terms of lower generation cost, the deferral of new generation, reduction in interruptible load and reductions in the level of expected unserved energy.

For northwards transfer the contingencies identified in 2.6.2 limit the maximum total transfer on QNI plus Directlink, so that any increase in transfer on Directlink requires a 1:1 reduction in QNI transfer. Hence there is no market/reliability effect for northwards transfer after the initial one year deferral of the Queensland augmentations. For southwards transfer Directlink adds to QNI transfer capability, however if Directlink is committed to provide pre-contingent support to the Gold Coast in 2005/06 it is not available for southwards transfer. The northwards transfer on Directlink reduces the QNI transfer capability and this may have a detrimental effect on both market and reliability benefits compared with Alternative 5.

3.3.3 Areas of particular interest or concern

PB Associates has been provided with the historical outage statistics for the Directlink facility[33], and their analysis reveals that the availability calculation (based on available active power capability) has been around 80% over the last 23 months. PB Associates is concerned that many of the benefits associated with this alternative, including deferral benefits described later in this report, are dependent on full or close to full active and reactive power capability being available. In its estimates of the deferral of Alternative 5, PB has assumed an availability of at least 99% for 120MW. Extended outages would reduce this availability and will significantly reduce Alternative 0's capability to provide these benefits.

[31] Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 3.2.2.2, page 18.

[32] Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 2.2, page 7.

[33] Letter from Dennis Stanley (DJV) to Sebastian Roberts (ACCC) dated 9 November 2004.

It should also be noted that PB Associates has relied on the information provided by the DJV that the proposed protection and control system upgrades can be completed and commissioned in a timely manner.

3.3.4 Assessment of estimated costs

This section provides an examination of the costs associated with Alternative 0.

3.3.4.1 Capital Costs

The DJV has provided a capital cost breakdown for the actual capital cost of Directlink in Schedule I.1 of the DJV application. This breakdown provides an actual capital cost of $145.08m (in July 2000 dollars) including capitalised interest of $5.522m. Converting to July 2005 dollars (assuming an average CPI value of 2.5% per annum), this equates to $164.1m. It is noted that this value does not include the cost to upgrade the control and protection schemes and the cost of additional spares.

The issue of reviewing the capital cost provided by the DJV is complicated by the fact that firm costing data for new HVDC Light® technology is not freely available in the public domain. PB Associates were able however to identify two sources, available in the public domain, that provide guidelines on the capital cost of HVDC Light® and/or Voltage Source Conversion (VSC) converters. It should be noted that ABB were involved in the development of both of these sources.

- In a review of the First International Workshop on Feasibility of HVDC Transmission Networks for Offshore Windfarms[34] ABB provided some guidance on the cost of utilising HVDC Light® based on a "Viking Cable Project"[35]. ABB indicated that a 70MW, 100km HVDC Light® project, including the converter stations but excluding cable laying, was $US30m ($AUD43.5m[36]) in 2000 dollars.

- In a paper published on the World Bank website a graph is provided for guidance on the cost of a 50MW VSC system, complete with 100% underground cable, on a per kilometre basis[37]. This paper indicated a cost of approximately $USD19.0m for a 50MW, 60km VSC transmission system in 2000 dollars. It should also be noted that this paper states that "technological developments have tended to push HVDC system costs downwards". Based on this statement, it is possible that these costs are on the high side.

Although not definitive costs, these sources can be used as a guide to determine whether the costs proposed by the DJV are reasonable in the light of information available in the public domain.

Cost Assessment Based on The Viking Cable Project Guidelines

The cost estimate provided is complicated by the fact that the cost is based on a 70MW HVDC Light® facility (whereas Alternative 0 is 3x60MW) and a cable distance of 100km (Alternative 0 is 59km). Further, cable installation is not included and must be estimated.

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[34] 30-31 March 2000 in Stockholm, Sweden.

[35] http://www.owen.eru.rl.ac.uk/documents/stockholm_hvdc_summary.pdf

[36] Based on an exchange rate of 0.69.

[37] Rudervall, Charpentier and Sharma, "High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper", page 8, obtained from World Bank website at http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf. Note that Rudervall and Sharma are both from ABB.

For comparative purposes, PB Associates assumed that cable installation is one third (1/3) of the actual installed cost of the Directlink cable in July 2005 dollars ($58m) which equates to $19.4m in July 2005 dollars. Based on a cable length of 59km, this means that cable installation is estimated to be $328k per km and the cost of cable is estimated to be $656k per km (for all three systems). To scale down the cost estimate from 100km of cable to 59 kilometres of cable, this estimated cost of cable per kilometre (in July 2005 dollars) is multiplied by 41 km and then subtracted from the cost estimate based on the Viking Project, in July 2005 dollars.

The results of the above are provided in Table 3-2. In this table, the cost of development, approvals, easements, site acquisitions, project management, equipment spares and AC underground cable at Terranora are assumed to be the same as provided for Alternative 1. Contingency costs are not included since these would not be compatible with the concept of efficient costs.

Table 3-2 - Cost Estimate for Alternative 0 Using Viking Cable Project Estimates

Project Component	PB Associate's Estimation ($m)
Development, Approvals, Easements and Project Management	
Development	3.1
Approvals	5.7
Easements & Site Acquisitions	2.6
Project Management	1.3
Equipment Spares	4
Transmission	
HVDC Underground Cable	19.4
110kV AC Underground Cable	4.6
Switchyard	
132 or 110kV Switching Bay	1.2
DC Converter Station[38]	120.7
Protection and Control Upgrades	0.5
TOTAL	**163.1**

Costs Based on the Paper Provided on the World Bank Website

This paper provides a table showing a price example for a 50MW VSC link with land cable. The price extracted for 50MW, 60 kilometres is approximately $US19m (assumed to be July 2000 dollars). It is assumed that this cost includes cable and cable installation. Using an exchange rate of 0.69, and an assumed average CPI of 2.5% pa, equates to $AU93.5m for three parallel 50MW systems, in July 2005 dollars.

The result of the above is provided in Table 3-3. In this table, the cost of development, approvals, easements, site acquisitions, project management, equipment spares and AC underground cable at Terranora are assumed to be the same as provided for Alternative

[38] A value of $AU120.7m is based on 3 x "Viking" type projects, $US90m (converted to July 2005 dollars), less 41km x $AU656k per kilometre to convert the cost estimate from 100km of cable supplied to 59km. This assumes 2.5% CPI per annum to bring the costs to 2005 dollars and an exchange rate of 0.69.

1. Contingency costs are not included since these would not be compatible with the concept of efficient costs.

Table 3-3 - Cost Estimate for Alternative 0 Using World Bank Paper Estimates

Project Component	PB Associate's Estimation ($m)
Development, Approvals, Easements and Project Management	
Development	3.1
Approvals	5.7
Easements & Site Acquisitions	2.6
Project Management	1.3
Equipment Spares	4
Transmission	
110kV AC Underground Cable	4.6
Switchyard	
132 or 110kV Switching Bay	1.2
DC Converter Station	93.5
Protection and Control Upgrades	0.5
TOTAL	**116.5**

PB Associates acknowledges that the estimates shown in Table 3-2 and Table 3-3 are based on three 70MW and 50MW systems respectively. Alternative 0 is based on three parallel 60MW systems. Therefore, it is reasonable that the capital cost of alternative 0 would be approximately midway between these values.

It should also be noted however that the higher cost assumes that the capital cost of the DC cable is as provided by the DJV. It is also understood that critical delays were experienced during the commissioning of Directlink which may have inflated the actual capital cost of Directlink beyond that which would be expected should such an installation be installed today.

PB Associates therefore estimates that the capital cost of Alternative 0 should be $139.8m in July 2005 dollars, which is determined as a mid point for the costs of three 70MW and 50MW systems.

3.3.4.2 Operating Costs

The DJV submission provides a present value operations and maintenance cost for Alternative 0 of $31.4m based on a 9% discount rate, or $2.931 m pa (July $2005). A breakdown is provided in Table 7.2 of the BRW report[39].

Comments on the individual O&M items are presented in Table 3-4.

Table 3-4 - Individual O&M items

General Management	A cost of $310k per annum indicates one person

[39] Report "Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, page 67.

(with assistant)	full time involved in the general management of Directlink. Given the nature of the facility, and the fact that for the majority of the time the facilities are unmanned, this appears excessive. PB Associates believes that a figure of $80k is more appropriate.
Operating management costs	A cost of $200k per annum indicates full utilisation of an engineer for the year, and PB Associates is of the opinion that this is reasonable.
Operations	A cost of $620k per annum indicates three fulltime persons, at $80k per annum, assuming a 2.5 labour multiplier. PB Associates understands that current operations are incorporated into Country Energy's existing control centre and therefore these costs are incremental to Country Energy's system operation costs. PB Associates requested, but have not received, proof that these direct operation costs are actually being incurred. This figure appears excessive and PB Associates has formed the opinion that Country Energy's operators are likely to spend only a fraction of their time (approximately 10minutes per hour) directly observing and operating the Directlink system. This equates to approximately $100k per annum.
Commercial/regulatory	DJV has indicated an amount of $198k per annum. This is the equivalent of a full time person for this role which would appear excessive when considered in addition to financial, legal, audit, management and operational resources. A figure of $30k is considered by PB Associates as more reasonable.
Financial Management (with assistant)	An amount of $218k is allocated for financial management. Given the additional financial reporting requirements needed to accommodate the Directlink business, this figure appears reasonable, when read in conjunction with the comments above on commercial/regulatory expenses.
Maintenance Costs	A cost of $360k per annum for all planned and unplanned maintenance/emergency response, including location and repair of any cable faults or equipment failures, appears reasonable.
Audit fees	The amount of $31k proposed appears reasonable.
Legal fees	The figure presented by the DJV of $50k appears reasonable given the complex nature of the market in which Directlink is operating and its unique market participation.
Insurance	The insurance figure provided of $312k appears reasonable in relation to the initial construction costs and risks.
Energy	This cost of $320k is considered reasonable

	based on average retail energy rates.
Communications	High speed, dedicated point to point digital communication lines can be expensive, especially if higher than normal reliability is sought. PB Associates considers the cost of $160k to be reasonable.
Corporate overheads	Considering that management, commercial/ regulatory, financial, auditing, legal and insurance expenses are separately listed, the residual overheads amount should be quite minimal. It would therefore seem unreasonable to include an additional $104k for corporate overheads. A figure of $50k is considered more appropriate.
Other Costs	Other costs are not explained and although only $52k it is difficult to accept this figure as reasonable. PB Associates believes that an amount of $10k would be more appropriate.

PB Associates, therefore, recommends that an efficient level of operating and maintenance cost would be in the order of $1.56 million per annum. This is slightly less than the general assumption of around 2% of construction costs for operating and maintenance, which would be $1.99m. It is the view of PB Associates that this reduction is appropriate based on the economies achievable through the utilisation of existing Country Energy staff and facilities.

3.3.4.3 Findings

PB Associates supports BRW's view that Alternative 0 be assessed as a reasonable alternative project for the purposes of applying the regulatory test.

PB Associates would expect (based on the limited information on costing of the technology in the public domain and based on BRW's comments regarding the DJV obtaining the Directlink equipment at a cost below the present market value of the technology) the capital cost to be below $139.8m [40]. In considering this position, PB Associates has also recognised that there were critical delays in the construction and implementation of Directlink that resulted in the interconnector not being able to take advantage of the window to commence operations before QNI. It is difficult to accept that these delays did not impose additional costs to the actual capital cost of the project. In comparing the costs of an efficiently constructed equivalent system, PB Associates believes there may be scope for cost reductions below the $139.8m described above.

PB Associates therefore recommends that a capital cost of $139.8m and operating cost of $1.56m per annum would be more appropriate for the evaluation of alternative 0.

3.4 ALTERNATIVE 1 – MODERN HVDC 'LIGHT®'

This alternative represents the option of providing a solution that is based on the functionality of the base case (Alternative 0) but constructed using modern-day equivalent materials, equipment and techniques.

[40] July 2005 dollars.

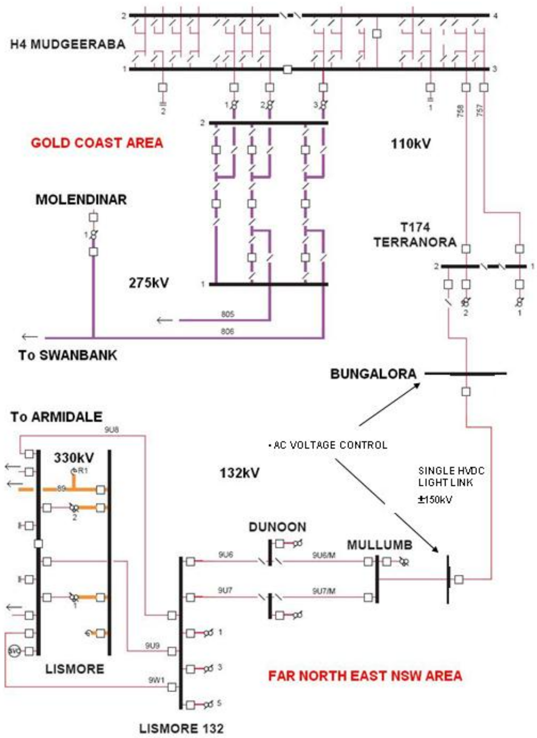
3.4.1 Technical Specification and Description of the Service Offered

This alternative is described as a modern HVDC Light® link (or equivalent) with a nominal 180MW capacity.

This alternative involves a "modern" HVDC Light® facility, comprising a single HVDC Light® link, with single converter stations at Mullumbimby and Bungalora, connected by underground cables with pre-contingent support capability and with the upgrade of the existing protection and control system to Code standards.

Alternative 1 is shown schematically in the following figure.

Figure 3-5 - Alternative 1 schematic diagram



3.4.2 Solution Capability

The DJV has identified the network services provided by Alternative 1. PB Associates provides the following comments.

3.4.2.1 Active Power Flow Capability

The HVDC Light® converters used in Alternative 1 allows the precise control of active power flows, in both directions, between the northern NSW Coast and Gold Coast regions. The active power flows are independent of generator scheduling and demands on either side of the link, unlike an AC interconnection. These flows can potentially be used to provide a number of support services to the AC networks, including loss minimisation, optimisation of network utilisation for reliability gains and wholesale market support. These services are also available in Alternative 0.

3.4.2.2 Reactive Power Flow Capability and Voltage Control

The HVDC Light® converters can supply or absorb reactive power independently of the active power flows, but within the bounds of a PQ curve similar to that used for Directlink. This is a significant benefit of the Voltage Source Conversion (VSC) technology used by HVDC Light®. The quantum and supply / adsorption capability of the converter stations can be manually adjusted by the operator. This service is also available in Alternative 0.

Alternative 1 could be used to also control the AC voltage at either end of the HVDC Light® link (i.e. at Bungalora and Mullumbimby). PB Associates understands that the improvement of the AC voltage control, to the degree that it is equivalent to an SVC, is included in the upgrade works proposed by the DJV, and therefore this service will also be available in Alternative 0.

3.4.2.3 Network Support Capability

The BRW report identifies that Alternative 1 connects into different parts of the transmission networks than the parallel AC interconnector, QNI. Although some interdependencies are identified between the AC interconnector and Alternative 1, BRW contends that Alternative 1 could provide network support services to these local networks and possibly defer network reliability augmentations in these networks. PB Associates notes however that such network support services will be limited to pre-contingent network support services (as defined in Section 2.2 of the BRW report[41]) in the case of Alternative 1 and may be limited by constraints in the AC transmission network. This service is identical to that provided in Alternative 0.

3.4.2.4 Facilitation of Inter-Regional Flows

The BRW report identifies that Alternative 1 allows better utilisation of available generation capacity throughout the NEM, and can create economic benefits in terms of lower generation cost, the deferral of new generation, reduction in interruptible load and reductions in the level of expected unserved energy.

For northwards transfer the contingencies identified in 2.6.2 limit the maximum total transfer on QNI plus Alternative 1, so that any increase in transfer on Alternative 1 requires a 1:1 reduction in QNI transfer. Hence there is no market/reliability effect for northwards transfer after the initial one year deferral of the Queensland augmentations. For southwards transfer Alternative 1 adds to QNI transfer capability, however if it is committed to provide pre-contingent support to the Gold Coast in 2005/06 it is not available for southwards transfer during that year.

3.4.2.5 Reference to “Modern” HVDC Light® Technology

In Section 3.3.1 of the BRW report, BRW refers to the use of “modern” HVDC Light® technology, indicating that the technology used by Directlink is not considered to be modern.[42] PB Associates’ understanding of the HVDC Light® technology is that the manufacturer of this technology, ABB provides two applications of the Voltage Source Conversion technology using Insulated Gate Bipolar Transistors (IGBTs). PB Associates understands that the first application (HVDC Light® A), using “two-level converter”

41 Report “*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*” by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 2.2, page 7.

42 Report “*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*” by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 3.3.1, page 19.

technology was used for the Directlink project with a DC voltage of ±80kV[43] and is currently being used by ABB on the Troll A project in Norway[44]. As this technology is currently being implemented on another project, this technology should be still considered to be current technology.

Further, PB Associates understands that the revised application (HVDC Light® B), using “three-level converter” technology has been used on the Murraylink facility, a HVDC Light® link connecting Victoria and South Australia with a DC voltage of ±150kV[45]. BRW has confirmed that the costing for Alternative 1 was based on the HVDC Light® B technology and that the DC voltage used in this cost estimate was ±150kV.

A “three-level converter” has 18 “valves” per converter. A “two-level converter” on the other hand has only 6 “valves” per converter. Therefore there would be no anticipated cost benefits with regards to the number of valves, except that the higher DC voltage in the former case would result in higher costs due to higher rated IGBTs (and therefore more expensive) and HV equipment being required.

PB Associates contends therefore that the use of the HVDC Light® B technology for this alternative represents a different application of the same technology, rather than the use of “modern” technology and that the references in the application to the use of “modern” technology can be misleading.

3.4.2.6 Physical Constraints of the Three-Level Converter

BRW has advised the Commission and PB Associates that Alternative 1 is based on a DC voltage of ±150kV, compared to the Directlink DC voltage of ±80kV. The concern with such an installation is that the increased DC voltage would result in the requirement for greater ground and phase to phase clearances for the HV equipment, including the AC and DC filter yards and as such would require a much larger footprint than the existing Directlink facility. Given the land constraints observed at Bungalora by PB Associates[46], it is unlikely that such a facility could fit on the existing footprint at Bungalora, and this would be more of an issue at Mullumbimby substation site where level land is at a premium.

3.4.2.7 Use of Overhead Line for HVDC Light® Applications

Section 3.3.1 of the BRW report states that:

“Overhead line cannot be used with HVDC Light® technology because of the susceptibility of the HV transistor equipment at the converter stations to lightning”[47]

The DJV has therefore concluded that Alternative 1 should comprise only underground cable and no overhead line.

PB Associates believes that this statement is a significant factor in the determination of the capital cost of Alternative 1, and we question the validity of this statement for the following reasons:

43 ABB Brochure – “*Directlink HVDC Light Project – New South Wales and Queensland*”, Pamphlet no POW-0025.
44 ABB Brochure – “*Troll A Precompression project Kollnes -Troll A, Norway*”, Pamphlet no POW-0033.
45 ABB Brochure – “*Murraylink HVDC Light Interconnection – Victoria – South Australia*”, Pamphlet no POW-0035.
46 During the site visit on 29 June 2004.
47 Report “*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*” by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 3.3.1, page 19.

- a review of publicly available information, including papers written on the technology and published on the ABB website, has not uncovered any statements supporting BRW's assertions;
- a review of publicly available information, including papers written on the technology and published on the ABB website, has found instances where ABB have stated that the connection of the HVDC Light® converters can be by a bipolar overhead line[48];
- it should be possible to apply industry accepted surge protection principles to prevent overvoltages caused by lightning strikes on an overhead DC line from entering the converter valves;
- any technology that is susceptible to overvoltages from lightning strikes on the DC side, should also be susceptible to lightning strikes on the AC side, given that supplies into the converters are supplied from overhead AC transmission lines at the Mullumbimby end;
- any technology that is susceptible to overvoltages from lightning strikes should also be susceptible to overvoltages caused by switching surges or cable faults, although these overvoltages will have a different wave shape and magnitude;
- BRW had previously supported an Alternative in the Murraylink Regulated Application for a HVDC link with DC overhead line, referring to it as having the same technical capabilities as Murraylink (and therefore implying VSC type technology); and
- ABB have a HVDC Light® pilot plant installed at Hellsjon in Sweden, which comprises connection of two HVDC Light® converters by overhead line and PB Associates have not located any reports in the public domain that detail adverse effects due to lightning overvoltages.

BRW responded to questions by PB Associates regarding this claim. The response states that IGBTs are more susceptible to lightning overvoltages than more conventional thyristor technology. This is not disputed by PB Associates, but PB Associates contends that there exists industry accepted practises, common in the transmission and distribution industry, that can be used to prevent such overvoltages reaching the IGBTs as well as the possible provision of fast acting protection solutions.

BRW has also advised PB Associates that ABB used "fast DC disconnectors" to clear faults on the transmission line, indicating the use of IGBTs to disconnect the DC side quickly in the case of a transmission line fault. The use of such a device is not found in any papers or literature provided in the public domain by ABB written specifically on the Hellsjon technology.

PB Associates has not found sufficient evidence to support the DJV's claim that overhead transmission lines cannot be used for Alternative 1.

It is understood that other (non technical) issues exist with regards to the use of DC overhead transmission lines. However, this aside, by incorporating an overhead DC line, with the strategic undergrounding recommended by BRW in Alternative 2, the capital cost of Alternative 1 could be reduced significantly.

48 As an example, Ericksson and Graham "*HVDC Light a Transmission Vehicle with Potential for Ancillary Services*" , presented at VII SEPOPE Conference, Curitiba, Brasil, May 21-26 2000, page 3 states "*The connection between the stations could be by a bipolar overhead line. This is the case in the test transmission between Hellsjön and Grängesberg in central Sweden. This transmission of 3 MW over 10 km has been in successful operation since March 1997.*"

3.4.3 Assessment of Estimated Costs

This section provides an examination of the costs associated with Alternative 1.

3.4.3.1 Capital Costs

The DJV submission provides a present value capital cost (including contingency) for Alternative 1 of $240.35 plus $13.0m IDC[49].

The DJV has provided a capital cost breakdown for the equipment costs for Alternative 1[50] together with other associated costs (approvals, easements, development project management etc)[51]. Unit costs were provided in the BRW Report[52]. The cost details for Alternative 1 are summarised in Table 3-5.

Table 3-5 - Alternative 1 capital costs

Project Component	Total Cost $m
Development, Approvals, Easements and Project Management	
Development	3.1
Approvals	5.7
Easements & Site Acquisitions	2.6
Project Management	1.3
Equipment Spares	4
Transmission	
HVDC Underground Cable	58.3
110kV AC Underground Cable	4.6
Switchyard	
132 or 110kV Switching Bay	1.2
DC Converter Station	137.2
Protection and Control Systems	0.5
Contingency	21.85
TOTAL	**240.35**

Table 3-5 shows that the DJV has assumed a total of $21.85m of contingency in determining the capital cost of Alternative 1.

As described for Alternative 0, the issue of reviewing the capital cost provided by the DJV is complicated by the fact that firm costing data for new HVDC Light®technology is not freely available in the public domain.

With regards to the cost of the converter stations, BRW has advised that the cost of Alternative 1 has been based on a ±150kV facility instead of the ±80kV used for

49 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.1, page 64.

50 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.3(c), page 70.

51 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.3(a), page 68

52 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September2004, Table 7.3(d), page 72.

Alternative 0. PB Associates has expressed concern regarding the size of the footprint and building due to the greater clearances required with the higher voltages[53].

PB Associates is also concerned that the cost of this higher voltage (±150kV) would be higher than the cost of a ±80kV, two level converter (the two level converter requires only 6 valves per converter instead of the 18 valves required per converter for the three level converter and the lower DC voltage would mean fewer IGBTs per valve and/or lower rated IGBTs).

The cost estimates referenced in the review of capital costs for Alternative 0 cannot directly be applied here, as these were provided at a time when the new 3 level converter technology had not yet been developed. However, PB Associates notes in the review of the Murraylink regulated application that a detailed cost estimate is provided for Alternative 2 of the Murraylink application, which is a ±150kV HVDC Light® facility[54]. Given that this is the only publicly available information identified by PB Associates, this information was used to determine a cost estimate. Further, PB Associates were advised by BRW that the costs for Murraylink were used by them to compare the cost of this alternative. It is therefore considered prudent to use the figures provided by the Murraylink Transmission Company.

Table 3-6 provides PB Associates' estimate for Alternative 1 based on 100% underground DC cabling. In determining these cost estimates PB Associates has also assumed that the costs for project management, development costs, approvals and easement, site acquisitions, AC Cable, equipment spares, HV switching bays and the required protection and control upgrades, are the same as the costs provided by the DJV for in Tables 7.3(a) and 7.3(c) of the BRW report. PB Associates has provided the costs of a fully overhead line construction due to the fact that, in the absence of legal directives for undergrounding it is appropriate to assume least cost alternatives which in this case represent the overhead construction type.

All contingency costs have been deleted since these would not be compatible with the concept of efficient costs.

Table 3-6 - Alternative 1 (Underground) - PB Associates Estimate

Project Component	Total Cost $m
Development, Approvals, Easements and Project Management	
Development	3.1
Approvals	5.7
Easements & Site Acquisitions	2.6
Project Management	1.3
Equipment Spares	4
Transmission	
HVDC Underground Cable	58.3
110kV AC Underground Cable	4.6
Switchyard	
132 or 110kV Switching Bay	1.2
DC Converter Station[55]	76.2
Protection and Control Systems	0.5

[53] See Section 3.3.2.6.

[54] Report "TransEnergie – Murraylink Selection and Assessment of Alternatives" by Burns and Roe Worley (BRW), 16 October 2002,

[55] Based on a value of $81.2 for the total cost of the HVDC Stations less $10.4 for the Monash substation ($70.8 assumed to be in July 2002 dollars) and scaled to July 2005 dollars.

TOTAL	**157.5**

The PB Associates' estimate of efficient costs for Alternative 1 (using 100% underground DC cable) is $157.5m (July 2005 dollars).

Table 3-7 provides PB Associates' estimate for Alternative 1 based on the use of overhead DC transmission lines and selective undergrounding as proposed by BRW for Alternative 2. The same costs for the DC overhead lines and underground cables as provided by BRW for Alternative 2 have been used.

Table 3-7 - Alternative 1 (Overhead and Selective Undergrounding) - PB Associates estimate

Project Component	Total Cost $m
Development, Approvals, Easements and Project Management	
Development	3.1
Approvals	5.7
Easements & Site Acquisitions	2.6
Project Management	1.3
Equipment Spares	4
Transmission	
HVDC Overhead Line	5.1
HVDC Underground Cable	20.3
110kV AC Underground Cable	4.6
Switchyard	
132 or 110kV Switching Bay	1.2
DC Converter Station[56]	76.2
Protection and Control Systems	0.5
TOTAL	**124.6**

The PB Associates' estimate of efficient costs for Alternative 1 (using a combination of HVDC overhead line and underground HVDC cable as recommended by BRW for Alternative 2) is $124.6m (July 2005 dollars).

Table 3-8 provides PB Associates' estimate for Alternative 1 based on the use of overhead DC transmission lines with no selective undergrounding. The same costs for the DC overhead lines as provided by BRW for Alternative 2 have been used.

Table 3-8 - Alternative 1 (100% Overhead DC Lines) - PB Associates Estimate

Project Component	Total Cost $m
Development, Approvals, Easements and Project Management	
Development	3.1
Approvals	5.7
Easements & Site Acquisitions	2.6

[56] Based on a value of $81.2 for the total cost of the HVDC Stations less $10.4 for the Monash substation ($70.8 assumed to be in July 2002 dollars) and scaled to July 2005 dollars.

Project Management	1.3
Equipment Spares	4
Transmission	
HVDC Overhead Line	11.8
110kV AC Underground Cable	4.6
Switchyard	
132 or 110kV Switching Bay	1.2
DC Converter Station[57]	76.2
Protection and Control Systems	0.5
TOTAL	**111.0**

The PB Associates' estimate of efficient costs for Alternative 1 (using 100% HVDC overhead line) is $111.0m (July 2005 dollars).

3.4.3.2 Operating Costs

The DJV submission provides a present value operations and maintenance cost for alternative 1 of $31.4m. The breakdown of the O&M costs is provided in Table 7.2 of the BRW report[58]. PB Associates has analysed this breakdown in the review of Alternative 0, and all comments detailed in 3.3.4.2 apply equally to Alternative 1. Therefore, PB Associates recommends that an efficient level of operating and maintenance cost would be in the order of $1.56 million per annum.

3.4.4 Findings

PB Associates supports BRW's view that Alternative 1 be assessed as a reasonable alternative project for the purposes of applying the regulatory test.

PB Associates believes that references to Alternative 1 providing "modern" technology is misleading given that there is at least one project underway at present using the same technology as Directlink (and Alternative 0). However, PB Associates acknowledges that the use of this newer application of the VSC technology represents a viable alternative to Directlink.

PB Associates has also not been provided with any credible evidence that overhead DC transmission lines cannot be used with this technology. No information has been found in the public domain by PB Associates to suggest that overhead lines cannot be used, and PB Associates has found a number of references from ABB indicating that overhead or underground DC connection can be used with the technology.

PB Associates would expect (based on the limited information on costing of the technology in the public domain) a capital cost of $157.5m (assuming 100% HVDC underground cable), $124.6m (assuming a combination of HVDC overhead line and underground HVDC cable and a figure of $111.0m (assuming all overhead) to be reasonable capital cost estimates.

PB Associates therefore recommends that a capital cost of $111.0m and operating cost of $1.56m per annum would be more appropriate for the evaluation of alternative 1.

[57] Based on a value of $81.2 for the total cost of the HVDC Stations less $10.4 for the Monash substation ($70.8 assumed to be in July 2002 dollars) and scaled to July 2005 dollars.

[58] Report "Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, page 67.

3.5 ALTERNATIVE 2 – CONVENTIONAL HVDC

Another alternative proposed by DJV for the purposes of the regulatory test is to provide a DC interconnector, at the location of the existing Directlink, based on conventional HVDC technology.

3.5.1 Technical Specification and Description of the Service Offered

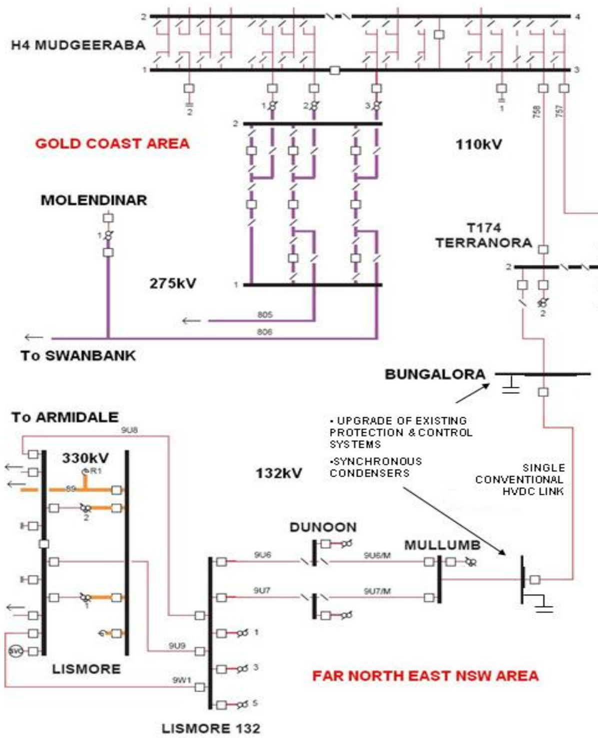
This alternative is described as a conventional HVDC link with a nominal 180MW capacity.

This alternative involves a conventional HVDC facility, comprising a single HVDC link, with converter stations at Mullumbimby and Bungalora, connected by a bipolar DC overhead line and underground cables in strategic locations. Alternative 2 also includes the following additions:

- synchronous condenser on each side of the HVDC link (primarily for commutation of the converters under low fault level conditions, but may be used to provide reactive power support); and
- protection and control systems to NEC standards

Alternative 2 is shown schematically in Figure 3-6. The DJV submission and the BRW report do not provide details as to the exact protection and control system upgrades required.

Figure 3-6 - Alternative 2 schematic diagram



3.5.2 Solution Capability

The DJV has identified the network services provided by Alternative 2. PB Associates provides the following comments.

3.5.2.1 Active Power Flow Capability

The conventional HVDC technology proposed in Alternative 2 allows the precise control of active power flows, in both directions, between the northern NSW Coastal and Gold Coast regions. The active power flows are independent of generator scheduling and demands on either side of the link, unlike an AC interconnection. These flows can potentially be used to provide a number of support services to the AC networks, including loss minimisation, optimisation of network utilisation for reliability gains and wholesale market support. These services are also available in the base case.

3.5.2.2 Reactive Power Flow Capability and Voltage Control

Unlike the HVDC Light® technology, the conventional HVDC technology cannot provide direct control of reactive power flows. Reactive power support and (to some degree) AC voltage control in discrete steps can be provided by the switching in and out of AC filters, but typically certain filters are required at particular power transfer levels[59] so this capability is limited.

For Alternative 2, the DJV has proposed the installation of additional reactive plant to provide reactive power support independent of the active power flows through the converter[60]. The synchronous condensers proposed by the DJV may provide additional reactive capability to support the Gold Coast and northern NSW coastal regions if required, though no details have been provided on the level of support available. Any reactive power support provided by this installation will most likely be in discrete steps rather than "SVC like" as in Alternatives 0 and 1.

3.5.2.3 Network Support Capability

The BRW report identifies that Alternative 2 connects into different parts of the transmission networks than the parallel AC interconnector, QNI. Although some interdependencies are identified between QNI and Alternative 2, BRW contends that Alternative 2 could provide network support services to these local networks and possibly defer network reliability augmentations in these networks.

3.5.2.4 Facilitation of Inter-Regional Control

The BRW report identifies that Alternative 2 allows better utilisation of available generation capacity throughout the NEM, and can create economic benefits in terms of lower generation cost, the deferral of new generation, reduction in interruptible load and reductions in the level of expected unserved energy. PB Associates agrees that, as a regulated link, Alternative 2 could be used in the overall planning of the NEM for these purposes.

For northwards transfer the contingencies identified in 2.6.2 limit the maximum total transfer on QNI plus Directlink, so that any increase in transfer on Directlink requires a 1:1 reduction in QNI transfer. Hence there is no market/reliability effect for northwards transfer after the initial one year deferral of the Queensland augmentations. For southwards transfer Directlink adds to QNI transfer capability, however if Directlink is

59 For harmonic levels and for the reactive demands of the converter valves.

60 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 3.4.2.2, page 22.

committed to provide pre-contingent support to the Gold Coast in 2005/06 it is not available for southwards transfer. The northwards transfer reduces the QNI transfer capability, and this may have a detrimental effect on both market and reliability benefits compared with Alternative 5.

3.5.2.5 Difference between Conventional HVDC and HVDC Light®

Section 3.4.1 of the BRW report identifies a number of key differences between the conventional HVDC facilities and HVDC Light®[61].

PB Associates offers the following comments regarding the differences identified in the report:

- *Conventional HVDC requires generators or synchronous condensers at both ends of the link to raise fault levels and ensure current commutation* - PB Associates cannot comment on whether or not the fault levels at Bungalora or at Mullumbimby are low enough such that "generators or synchronous condensers" are required. This has been stated in the BRW report, without any justification on how the existing fault levels will affect current commutation of a conventional HVDC facility;

- *Conventional HVDC converters always absorb reactive power from the system at both terminals* – PB Associates agrees with this statement though reactive power adjustment would normally be provided through the switching of AC filters, which are required at certain active power levels to provide reactive power to the converters;

- *Conventional HVDC systems change their reactive power demands in accordance with their active power flow* – PB Associates agrees with this statement. The switching in and out of the AC filter banks is dependent on the requirement for these banks at various active power levels. The banks are also used to supply the reactive power requirements of the converters, which increases with the active power transfer level;

- *HVDC current commutated converters do not require the DC link to be implemented using underground cable because of the thyristor technology rather than HVDC Light® transistor technology* – PB Associates does not agree that this is a difference between the two technologies. Refer to section 3.4.2.7 of this report.

PB Associates concurs with the assertion by the DJV that this alternative would require additional reactive plant in order to provide the level of reactive power support provided by Alternative 0. Note, however, that such reactive support will not be 'SVC-like' as in the Alternatives 0 and 1.

3.5.3 Assessment of Estimated Costs

This section provides an examination of the costs associated with Alternative 2.

3.5.3.1 Cost of conventional HVDC compared with the cost of HVDC Light®

PB Associates understands that ABB have developed and marketed the HVDC Light® on the basis that it allows HVDC to be economic at lower active power transfer levels and

[61] Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Section 3.4.1, page 21.

shorter distances[62]. Therefore it is not clear why the cost estimates provided by BRW show that for the relatively small MW transfer of 180MW and short distances (less than 60km) the conventional HVDC system is approximately 40% cheaper than the HVDC Light® option[63].

Part of this cost difference may be attributed to the fact that BRW has used DC overhead transmission line for a significant part of the route. However, even if the costs for overhead transmission lines are used in Alternative 1 (which is 100% underground cable), we would still expect Alternative 2 to be more expensive than the HVDC Light® option. The fact that BRW's estimate of the conventional HVDC is cheaper than the HVDC Light® technology seems to be in conflict with ABB's assertion that the HVDC Light® technology is more economic for lower power transfers over shorter distances.[64] .

The information above supports the reduced capital costs for Alternative 0 and Alternative 1 detailed in sections 3.2.4.1 and 3.3.3.1 of this report respectively. It is expected that the cost of conventional HVDC would be considerably higher than the cost of HVDC Light®.

3.5.3.2 Capital Costs

The DJV submission provides a present value capital cost (including contingency) for Alternative 2 of $143.1 plus $10.1m IDC[65].

The DJV has provided a capital cost breakdown for the equipment costs for Alternative 2[66] together with other associated costs (approvals, easements, development project management etc)[67]. Per unit costs were provided in the BRW Report[68]. The cost details for alternative 2 are summarised in Table 3-9.

Table 3-9 - Alternative 2 capital costs

Project Component	Total Cost $m
Development, Approvals, Easements and Project Management	
Development	4.2
Approvals	6.8
Easements & Site Acquisitions	2.6
Project Management	1.3
Equipment Spares	2.3
Transmission	

62 The ABB website states that "*Classical HVDC is most cost effective in the high power range, above approximately some 250 MW. HVDC Light, on the other hand, comes in unit sizes ranging from a few tens of MW up to presently 350 MW and for DC voltages up to ±150 kV*." Reference: http://www.abb.com/global/GAD/GAD02181.NSF/0/C1256D71001E0037C12569C9006068F7?OpenDocument&v=17EA&e=us.

63 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.1, page 64, shows a present value capital cost of alternative 2 (conventional HVDC) to be $143.1m and a present value capital cost of alternative 1 (HVDC Light) to be $240.5.

64 ABB's marketing information suggests that HVDC Light® is aimed at a lower cost solution.

65 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.1, page 64.

66 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.3(c), page 70.

67 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.3(a), page 68.

68 Report "*Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC*" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, Table 7.3(d), page 72.

HVDC Underground Cable	20.3
HVDC Overhead Pole Line	5.1
110kV AC Underground Cable	4.6
Switchyard	
132kV 50MVAr Synchronous Condenser	4.2
110kV 25MVAr Synchronous Condenser	2.6
132 or 110kV Switching Bay	1.2
DC Converter Station	74.4
Protection and Control Upgrades	0.5
Contingency	13.0
TOTAL	**143.1**

Table 3-9 shows that the DJV has assumed a total of $13m of contingency in determining the capital cost of Alternative 2.

As detailed in Section 3.5.3.1 of this report, PB Associates would also expect the cost of the conventional HVDC option to be higher than the HVDC Light® option, particularly at such low active power transfer levels and transmission distances, even though Alternative 2 assumes approximately 75% of the DC transmission route to be overhead.

PB Associates is unable to provide alternative costing for the conventional HVDC converter stations due to the lack of public information at such low MW levels. The public data that is available provides cost values for power ratings in the range of 1000MW to 2000MW[69] but, as conventional HVDC is not, typically, used for power applications as low as 180MW, it is not recommended to use this data for the smaller MW capabilities and shorter distances.

Table 3-10 provides PB Associates' estimate for Alternative 2 based on the use of overhead DC transmission lines with no selective undergrounding. The same unit costs for the DC overhead lines and the same switchyard, development, approvals, easement and project management costs as provided by BRW for Alternative 2 have been used. PB Associates has provided the costings of a fully overhead line construction due to the fact that, in the absence of legal directives for undergrounding it is appropriate to assume least cost alternatives which in this case represent the overhead construction type.

Table 3-10 - Alternative 2 (100% Overhead DC Lines) - PB Associates Estimate

Project Component	Total Cost $m
Development, Approvals, Easements and Project Management	
Development	4.2
Approvals	6.8
Easements & Site Acquisitions	2.6
Project Management	1.3
Equipment Spares	2.3
Transmission	
HVDC Overhead Line	11.8
110kV AC Underground Cable	4.6
Switchyard	
132kV 50MVAr Synchronous Condenser	4.2

69 Carlsson, Lennart "*Technologies for Power System Interconnection*", located at http://www.staffexchange.org/documentcenter/DocumentDisplayHtmlBody.asp?MessageFile=lcarlsson82820006440.eml&LinkAdd=Intcon.doc

110kV 25MVAr Synchronous Condenser	2.6
132 or 110kV Switching Bay	1.2
DC Converter Station	74.4
Protection and Control Upgrades	0.5
TOTAL	**116.5**

The PB Associates' estimate of efficient costs for Alternative 2 (using 100% HVDC overhead line) is $116.5m (July 2005 dollars).

Based on the lack of lack of public information of the cost of conventional HVDC at such low MW levels, PB Associates has not challenged the BRW figures for this alternative except that, as for the other Alternatives, we do not believe that contingencies and IDC's should be included in the cost estimates.

PB Associates would expect a capital cost of $130.1m (assuming a combination of HVDC overhead line and underground HVDC cable and no contingencies) and a figure of $116.5m (assuming all overhead and no contingencies) to be reasonable capital cost estimates.

3.5.3.3 Operating Costs

The DJV submission provides a present value operations and maintenance cost for alternative 2 of $31.4m. The breakdown of the O&M costs is provided in Table 7.2 of the BRW report[70]. PB Associates has analysed this breakdown in the review of alternative 0 (as the cost and hence the breakdown is the same), and all comments detailed in 3.3.4.2 applies equally to alternative 2.

3.5.4 Findings

PB Associates supports BRW's view that Alternative 2 be assessed as a reasonable alternative project for the purposes of applying the regulatory test.

However, PB Associates would expect (based on the limited information on costing of the technology in the public domain) the capital cost for Alternative 2 for such small MW transfers and short distances to be above that of Alternatives 1 and 0. This is not in the case of the capital costs provided in the DJV submission.

PB Associates therefore recommends that a capital cost of $116.5m and operating cost of $1.56m per annum would be more appropriate for the evaluation of alternative 2.

3.6 ALTERNATIVE 3 – AC LINK WITH PHASE-SHIFTING TRANSFORMER

At the time that the Directlink project was initially conceived there was no permanent network interconnection between NSW and Queensland (QLD). The relatively small capacity of Directlink, in comparison with the size of the two transmission networks to which it is connected[71], made DC a natural choice on which to base the interconnector technology. However, the installation of the significantly larger capacity QNI interconnector between NSW and Queensland means that the two previously isolated power networks are now electrically integrated through a double circuit 330kV AC

70 Report "Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC" by Burns and Roe Worley (BRW), Revision 1, dated 22 September 2004, page 67.

71 Directlink provides a degree of connectivity between between Powerlink's transmission network in Queensland and TransGrid's transmission network in NSW. Although it should be noted that Directlink does not provide direct interconnection at the transmission level as a result of it being connected to Country Energy's 110kV distribution network at both ends.

transmission link connecting Dumaresq substation in NSW with Bulli Creek substation in Queensland. Directlink now operates in parallel with QNI and so some of the system characteristics which originally influenced the use of DC for the interconnection, have now changed.

There are presently power flow constraints between NSW and Queensland in both a northward and a southward direction[72]. In addition, BRW has determined interface limits between the Gold Coast and Northern NSW[73]. BRW state that these interface limits are based on publicly available transfer limits and "engineering judgement" to determine the impact of future augmentations. These limits are tabulated in the BRW report[74] and form the basis of the modelling limits used by TEUS in their determination of market benefits.

When Directlink operates in a northerly direction, power flows between NSW and Queensland are limited by constraints around the far North Coast area. Principally, these are:

- Armidale to Lismore 132kV thermal limit;
- Tamworth to Armidale 330kV thermal limit;
- Liddell to Tamworth 330kV thermal limit;
- Lismore to Mullumbimby 132kV thermal limit; and
- Lismore 132kV voltage control limit.

Southward power flows between south east Queensland and northern NSW are subject to constraints, mainly voltage stability limits, in the Gold Coast area – particularly the thermal limits associates with the Mudgeeraba to Terranora 110kV circuit and the Swanbank to Mudgeeraba/Molendinar line.

Powerlink claim that their proposed construction of a 275kV transmission line between Greenbank and Maudsland would address some of these existing power flow constraints and would increase the Gold Coast voltage stability limit by approximately 100MW. In addition, the planned augmentation would increase the opportunity for southward flow on Directlink.

BRW have assessed that Alternative 3 does not contribute to QLD to NSW inter-regional transfer capability. Details of their assessed transfers are contained in the Directlink Joint Venture submission[75]. BRW have assessed that from 2006/07 Alternative 3 could provide a maximum of 148MW (decreasing to 123MW in 2019/20) of transfer capacity from the Gold Coast to the Northern NSW area[76], but requires a reduction in the QNI southwards capability of 150 MW. In the absence of any parallel lines QNI is rated at 950MW QLD to NSW and hence Alternative 3 decreases (by 2 MW) the inter-regional transfer capacity in a southerly direction.

Alternative 3, a 132kV AC link with 180MW capacity, in common with Alternatives 0, 1 and 2, aims to overcome these augmentation requirements, to a lesser or greater degree, by control of the power flows across the AC link by the use of phase shifting transformers.

72 As described in the Powerlink Annual Planning Report 2004, page 20. Interface limits between the NEM regions are published by NEMMCO in their Statement Of Opportunities (SOO) document.

73 Appendix D of the Directlink Joint Venture Application for conversion to a Prescribed Service, dated 22 September 2004 (The Revised application).

74 Section 5, Transfer Limits of Appendix D.

75 Application for conversion to a Prescribed Service dated 22 September 2004, Appendix D, Table 5.6(a) – medium load growth scenario.

76 Power flows over QNI would have to be limited to a maximum of 800MW over the same period.

3.6.1 Technical specification and description of the service offered

In this section we describe the service being offered in terms of its technical specification.

3.6.1.1 Concept of the use of a phase-shifting transformer

The basic principal of the phase-shifting power transformer (PST) is relatively straightforward. The transformer uses on-load tap-changing devices to alter the vector phase shift between the primary and secondary sides of the transformer in order to provide some control over the flow of active (real) power through the transformer that operates in parallel with another AC line or network, by changing the sharing of power transfer between the two paths. The phase shifts are normally introduced in well defined steps – as per the design of the tap-changing device. Also, it is often possible to change the sign of the phase shift (advance or retard) in order to control the direction, as well as the magnitude, of the active power flow through the transformer.

The extent to which the phase angle between the link's sending and receiving ends will influence the flow of active power across the link depends on a number of network characteristics including the ratio of the reactance to resistance of the controlled network. On a purely inductive transmission link, the transfer of active power between sending and receiving ends of the link will depend almost entirely on the phase (or power) angle between the ends. Conversely, the flow of reactive power across the link will depend upon the scalar difference between the sending and receiving terminal voltages – again, assuming a purely inductive transmission link.

On a practical network having some degree of network resistance, the phase angle will also have some effect on the transfer of reactive power. Likewise, on a practical network, some of the difference between the voltage magnitudes at the two ends will be due to resistance in the link.

A common application is in re-balancing the natural division of circuit flows in order to optimise the utilisation of parallel operating circuits having different ratings and impedances. Although in any AC interconnection there will be a natural power flow level, a PST can be used to inject a boost, or modifying, voltage between the two interconnected nodes. Depending on the design, the boost voltage is often in quadrature phase advance such as to give rise to a line current which is in phase with the line voltage – and hence provide a real power flow adjustment across the link. PSTs are widely used in Europe and the US.

3.6.1.2 Technical description of Alternative 3

Alternative 3 is a 132kV AC link including a 132/110kV PST at the Queensland end. The PST comprises three single phase units with a ± 30 degree tapping range. Single phase units were recommended by BRW in order to reduce the costs of maintaining a spare transformer.

The Alternative 3 link would be designed with a capacity of 180MW and would use tap - changers to control flow levels and direction. Hence flows over the link would continually change according to the variation in loads and generator dispatch patterns that cause changes in transfer across QNI and, in particular, whenever any network elements were subject to forced outages. This would require that the flows over the link would have to be continuously monitored and controlled so as to maintain post contingent support to northern NSW and also to ensure that all network elements were operated within their ratings. This is the major disadvantage of operating an AC link in place of Directlink.

3.6.1.3 Other components of Alternative 3

Alternative 3 also provides for the installation of small switched shunt capacitors at each end of the AC link to assist in the provision of local post-contingent voltage control. PB Associate's understanding is that the pre-contingent support offered in this alternative would necessarily require a facility to remotely operate the phase shifting characteristics of the transformers.

Additional components of Alternative 3 include:

- protection and control systems;
- overhead 132kV circuit; and
- substation modifications at Terranora and Mullumbimby (including the upgrading of protection, control and communications equipment)

The protection and control systems include the capability to adjust the transformer phase angle to help relieve network constraints in the event of a critical network fault.

3.6.2 Solution capability

The key difference between this AC alternative and the DC options previously discussed is the level of controllability of the power flow across the link and also its independence – or the extent to which the performance of the AC link depends upon flows in other parts of the two interconnected networks. Of particular interest is the reversal of power flows on QNI and the ability of the PST used in Alternative 3 to maintain power flows in the opposite direction over the parallel AC link. PB Associates was advised that the PST in Alternative 3 is designed to achieve full flow south when QNI flow is full northwards, but not to achieve northwards flow when QNI is flowing southwards.

3.6.2.1 Active power flow capability

This Alternative does provide interconnection between NSW and Queensland – albeit limited. It has no additional usable inter-regional capacity in either direction compared with Alternative 5. The power transfer limitations associated with this Alternative stem from three main areas. These are:

- the constraints associated with the existing Gold coast and northern NSW networks;
- the relatively small power transfer capacity of the AC link when compared to the capacity of QNI; and,
- the technical dependence of the proposed AC Alternatives (including Alternative 3) on the market transfers and characteristics of QNI.

The second and third points are related since the inability of Alternative 3 to operate independently of QNI is a function of both the mismatch in power transfer capability and the use of AC for the Alternative – which, unlike a DC link, does not provide for completely independent/de-coupled operation.

In broad terms, the use of an AC link with PST in Alternative 3 would provide a level of control of active power flow which is considerably less than which might be obtained by a DC link (Alternatives 0, 1 and 2) but greater than that which would be achieved using a simple auto-transformer (Alternative 4).

3.6.2.2 Facilitation of inter-regional control

This Alternative provides a limited amount of inter-regional control – principally through the control of active power between NSW and Queensland. The interdependence on the operational state of QNI means that power flows across the AC link under this Alternative cannot be controlled (entirely) independently at all times. To this extent inter-regional control is facilitated only to a limited degree.

Transferring active power in a counter direction to that on QNI is likely to be difficult because the voltage magnitudes, phase angles and network impedances in the system will support a natural flow of power in the same direction as that on the (much greater capacity) QNI. This aspect is made clear in the BRW report.

For northwards transfer the contingencies identified in section 2.6.2 limit the maximum total transfer on QNI plus this Alternative, so that any increase in transfer due to the presence of the Alternative requires a 1:1 reduction in QNI transfer. Hence there is no market/reliability effect for northwards transfer. For southwards transfer the Alternative requires that the transfer on QNI must be limited to 800 MW when the alternative carries approximately 150 MW south, a total of 950 MW south. Since the maximum southwards transfer on QNI alone is 950 MW, this represents no improvement in southwards capacity compared to Alternative 5. In brief Alternative 3 has the same inter-regional impact as alternative 5 (zero)

3.6.2.3 Comparison with the base-case

PB Associates has defined the 'base-case' as being the existing Directlink facility, all upgrade works of the existing protection and control systems and with the capability to provide pre-contingent support to *either* the Gold Coast region *or* the northern NSW coastal region. As part of our review we will be comparing the functionality and potential for solution provision of each of the Alternatives with this base-case.

Alternative 3 can also provide varying degrees of support to the northern NSW region. The magnitude and direction of power flow across the link is affected by the tap-change mechanism in the phase-shift transformers – as a result the response time would be comparatively slow. This is acknowledged in the BRW report[77]. Whilst Alternative 3 could operate in either direction, the extent to which this is achievable would depend on the transfers on QNI. With zero phase shift the Alternative's transfer will broadly track QNI flow. The phase shift is used to make the Alternative flow south, to provide pre-contingent support at the Lismore end, even while QNI flows north. The limit is caused by thermal ratings in Queensland

The base case is capable of operating independently of QNI.

3.6.2.4 Overall capability to provide a network support solution

As a result of meetings with DJV's consultants, BRW, PB Associates has been able to better understand the operational limitations and complexities of using an AC phase shift transformer in place of Directlink.

The complexities arise, principally, as a result of the need for the operational set point of the PST to be continually adjusted to suit the prevailing network conditions – in both QLD and NSW. For example, transfer across the AC link cannot be set to a fixed value but will change following the outage of any of the transmission lines between Armidale and

77 Directlink Joint Venture, Appendix D, BRW Report, 'Selection and assessment of alternative projects to support conversion application to ACCC', 5 May 2004.

Tarong. Furthermore, the PST phase angle setting must also be continually trimmed/adjusted in accordance with the magnitude (and direction) of flows on QNI.

Even with the ability to control the PST up to +/- 30 degrees, the total north-south transfer on QNI needs to be limited to 800MW if an outage of the Mudgeeraba to Terranora line is not to result in overloading of the other parallel 110kV line while the system is configured to provide support for the potential loss of the Armidale to Coffs Harbour 330kV line. The result is that the total north-south power transfer capability under Alternative 3 is the same as that achieved by QNI alone.

BRW's modelling demonstrated that increasing the available phase angle of the PST would not help in addressing the limitation on the total north-south power flow.

Furthermore, if the proposal to increase the nominal capability of QNI from 950MW to 1100MW proceeds (as expected) then contribution of Alternative 3 in the provision of network support is expected to decrease further. BRW's modelling confirmed this.

3.6.2.5 Technical capability of phase-shift transformers

In its report[78], BRW estimate that a phase-shifting transformer would need to be capable of delivering shifts of up to 75 degrees in order for Alternative 3 to secure independence from the operation of QNI. Furthermore, that even at these relatively large phase-shift angles, any increase in the power transfer capability of QNI would jeopardise this independence of operation. The BRW report also observes that the direction of active power flow is selectable but that this, also, is somewhat limited due to the interdependence on the prevailing conditions on QNI. The thermal limit into Terranora is reached at a relatively modest phase shift. As identified in the BRW report a high overall +/- range would be needed to transfer to maximum capacity in either direction while QNI was transferring the other way. DJV decided not to assume this range, and to achieve the capacity for southwards transfer only, thus foregoing the relatively minor benefit of deferring the Gold Coast augmentation for one year.

Maximum transformer phase angle

PB Associates notes that the technological application of phase shifting transformers as a means of sharing active power flow between two paths is well understood and a firmly established and widely used technique for the management of power systems. Whilst we are aware that it is possible to design and operate phase shifting transformers at angles greater than +/-30 degrees PB Associates shares some of BRW's concerns regarding the practical network implications of attempting to operate the AC link at large phase angles.

PB Associates is also aware of the wide range of designs available for phase shift transformers. In common with the majority of large power transformers, phase shift transformers are designed on a bespoke basis depending on the specific application. We also note that it is very often the availability of a suitable tap-changer that determines the viability of the combination of the required rating together with the necessary maximum phase angle[79].

Nevertheless, the extent to which operation of the phase-shift transformer at large angles may impact on switchgear capability will depend on the location and design duty of the

78 Directlink Joint Venture, Appendix D, BRW Report, 'Selection and assessment of alternative projects to support conversion application to ACCC', 5 May 2004.

79 PB Associates are aware of a power transformer manufacturer who has designed and delivered a PST with +/- 46° no-load phase shift. In this particular case the load phase shift by moved by regulation to +36°/-56° and operation was capped at -46° due to the effects of yoke saturation). We understand that higher phase angles may be possible although the design changes required to lower the nominal flux density would increase the cost.

particular circuit breaker in question. It is not clear which switchgear the BRW report refers when it suggests that a large phase shift angle could introduce “severe operational limitations and safety issues relating to switchgear capability”. PB Associates are of the view that more work would need to be done in this area before the impact on switchgear operation and safety could be properly quantified.

3.6.2.6 Under grounding of sections of the AC circuit

Alternative 3 as proposed by the DJV includes the under-grounding of sections of the 132kV AC single circuit line in order to meet with the environmental concerns and to also address the practical difficulties associated with constructing an overhead line on certain parts of the route.

PB Associates understands that it may be difficult to construct the entire 132kV circuit length associated with Alternative 3 as overhead line. Meetings held with Tweed Shire Council also support this view.

BRW engaged URS Australia Pty Ltd to undertake a study of proposed transmission line routes between Mullumbimby and Terranora in order to determine potential routes for an overhead transmission line, or sections of overhead line. URS identified a corridor 1km wide and 47 km long route that may receive environmental and planning approval for the construction of a transmission line. They further identified that approximately 18km of the line would require undergrounding in order to obtain approval – 10km at the Terranora end and 8km at the Mullumbimby end.

PB Associates has reviewed the DJV cost estimates but also provided the costs of a fully overhead line construction. This is due to the fact that, in the absence of legal directives for undergrounding it is appropriate to assume least cost alternatives which in this case represent the overhead construction type.

3.6.2.7 Identified additional benefits

Whilst an AC connection may contribute to overall system inertial response, with the prospect of an increase in transient stability limits[80], the network benefits of this are likely to be significantly outweighed by the reduced level of power control, the inter-dependence on the operation of QNI and the associated thermal constraints.

3.6.3 Assessment of estimated costs

PB Associates has reviewed the costs for this alternative contained in the BRW Report and concluded that the total project capital costs would be $61.8m. This comprises:

Table 3-11 – Capital Construction Costs for Alternative 3 (Including some Undergrounding) (July 2005 Dollars)

Project Component	Total Cost $m
Construction Contract	$45.5m
Project Management	$1.3m
Approvals	$6.8m
Development	$4.2m

80 Inertial response is the inherent response to changes in system frequency of synchronised generators and is an important aspect of the operation and control of an integrated AC power system.

Spares	$0.9m
Easements	$3.1m
TOTAL	**$61.8m**[81]

As discussed in section 3.6.2.6 the estimates using fully overhead construction are as follows:

Table 3-12 – Estimated Capital Costs for Alternative 3 - Overhead Construction

Project Component	Total Cost $m
Construction Contract	$24.7m
Project Management	$1.3m
Approvals	$6.8m
Development	$4.2m
Spares	$0.9m
Easements	$3.1m
TOTAL	**$41.0m**

The savings are achieved through the utilisation of much lower cost overhead cable and construction costs. In addition, an estimated annual operating and maintenance cost of $0.49m would apply for Alternative 3.[82]

3.6.4 Findings

In general PB Associates are comfortable with the general conclusions reached by BRW – that Alternative 3, whilst technical feasible, would present some operational difficulties in practice. The duty placed on the PST through the requirement to constantly monitor a number of critical network conditions and continually vary the operation of the PST accordingly, makes this alternative operationally challenging.

Whilst PB Associates would not advocate a PST based solution requiring greater phase angles, we recommend that Alternative 3, as described, does represent a technically possible alternative to Directlink and should therefore be included as an alternative in the markets benefits test. It is recognised, however, that in using Alternative 3 to defer the construction of the 330kV Lismore Dumaresq line, the capacity flowing over QNI would be reduced by any transfer over the alternatives on a 1:1 basis.

The BRW studies shown in their Table 4.3.4 indicate that Alternative 3 can only defer augmentations in NSW as detailed in Alternative 5 until 2010. The studies also indicate in their Table 4.4.3 that Alternative 3 cannot defer the Qld augmentations over the 2005/06 period. PB Associates has reviewed these studies and believes that these findings are reasonable.

The estimated capital costs for constructing this Alternative would be $41.0 million, with an annual operating cost of $0.49 million.

81 These costs represent construction of a line with the proportion of overhead and underground circuit suggested by the URS report – as described in section 3.6.2.6.

82 This is based on a figure of 2% of construction costs. PB Associates believe this to be a reasonable and realistic estimate for a scheme of this type.

3.7 ALTERNATIVE 4 – AC LINK WITH CONVENTIONAL TRANSFORMER

This option proposes the use of a 250MVA rated AC link between Bungalora and Mullumbimby. The link would make use of 132/110kV autotransformers to facilitate interconnection of the two AC networks.

3.7.1 PB Associates comments on Alternative 4

BRW studies have demonstrated that the link would need to be rated at 250MVA to avoid it constraining active power flows on QNI. The flows on the AC link under this alternative would not be controllable but would be a function of a number of associated parameters – particularly the flows on QNI and also the distribution of loads in the (electrical) vicinity and the relative impedances of the network components. Moreover, the direction of flow would be totally dependant on the power flows on QNI.

PB Associates recognises the limitations of a traditional AC link, effectively operating in parallel with an interconnector of significantly higher rating, and agrees with BRW that this Alternative is likely to offer little network support and is unlikely to provide capital deferral benefits for a number of credible QNI operational scenarios.

On this basis, PB Associates agrees with DJV that Alternative 4 offers no significant benefits and is, therefore, not a credible Alternative to Directlink and is not considered further in our assessment.

3.8 SUMMARY OF THE ALTERNATIVES

The DJV submitted the 5 key alternatives discussed in this section, in its application to the Commission, and also the existing DC interconnector as a base case. PB Associates believes that the DJV adequately identified the principal options available to provide the required electrical network capabilities to the region.

However, PB Associates also identified a number of modifications to these alternatives which we believe materially alter the levels of services and the timing and levels of expenditures. In particular, the upgrading of 132kV lines by TransGrid and the anticipated introduction of generation in northern NSW should enable deferrals of major augmentations envisaged by TransGrid.

Of the Alternatives proposed by the DJV, all are considered technically feasible with the exception of Alternative 4 – an AC interconnector using conventional transformers.

In terms of the capital costs proposed by the DJV for each of the viable Alternatives, PB associates believes that these have been generally overstated and that IDCs and contingency costs should not be included.

Table 3-13 shows a summary of the capital and operating costs estimated by PB Associates for each alternative. Alternatives 1, 2 and 3 are based on full overhead construction.

Table 3-13 – PB Associates estimate of capital and operating costs of alternatives – July 2005 dollars ($M)

	Alternative 0	Alternative 1 (OH)	Alternative 2 (OH)	Alternative 3 (OH)	Alternative 5 NSW Component
Capital Costs	139.8	111.0	116.5	41.0	129.9
Annual Operating Expenditure	1.56	1.56	1.56	0.49	0.55

Table 3-14 shows the relative present value of expenditures for each alternative and compares these figures with the figures provided by the DJV.

Table 3-14 – Comparison of Present Value Costs for Alternatives – 2005 dollars ($m) (9% Discount Rate)

	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5 NSW Component
DJV Submission	$196.3	$284.9	$184.6	$103.8	$182.5
PB Associates	$156.6	$127.8	$133.3	$46.3	$137.2

These present value figures include an assumption of 40 year asset lives for these projects and the commensurate operating expenditures.

Table 3-14 shows the comparison of present value costs between the figures provided by the DJV and those determined by PB Associates. In relation to Alternative 5, Table 3-14 does not include the costs of Queensland augmentations which would require a capital expenditure of $48.9m and an annual operating allowance of $0.98m. Alternatively the Queensland deferral benefits are subject to a commercial agreement for a payment of $2.7m.

In addition to these variations, PB Associates has also identified that the timing of the augmentations by TransGrid will materially alter the present value costs of expenditures relating to Alternative 5. The estimated deferral periods and values for each alternative are provided in the following tables. Note that the table assumes a maximum of 10 years for a reasonable planning period (to 2014/15) and that the additional works discussed in section 3.2.4.2 are incorporated.

Table 3-15 – Alternative 5 Deferrals offered by each Alternative

	Alternative 0	Alternative 1	Alternative 2	Alternative 3	Alternative 5
Qld Deferrals	2005/06	2005/06	2005/06	0	NA
NSW Deferrals	2011/12 – 2014/15	2011/12 – 2014/15	2011/12 – 2014/15	0	NA

Table 3-16 –Alternative 5 Present Value Costs NSW Deferrals– 2005 dollars ($m)

NSW Deferrals	7%	9%	11%
Without Directlink (Alt 0, 1, or 2)	$91.43	$80.97	$72.07
With Directlink (Alt 0, 1, or 2)	$69.75	$57.36	$47.48
Transmission Deferral Benefit of Directlink	$21.68	$23.61	$24.60

Table 3-16 shows the impact of timing on the present value of expenditures for Alternative 5, with and without Directlink (or the equivalent Alternatives 1 or 2). The benefits of Directlink are projected to commence in 2010/11. Deferral of the need for the 330kV Lismore to Dumaresq line is achieved through other augmentations already planned by TransGrid and the anticipated generation proposed for the region. The additional benefit offered by Directlink is to potentially defer TransGrid's construction of the proposed 330kV line from Dumaresq to Lismore until 2016/17. However, given that detailed planning has only been undertaken by TransGrid for ten years and that many uncertainties exist regarding other possible scenarios beyond is period, including the challenges of gaining approval to build the third line into Terranora, the present value of deferral benefits has only considered for the period until 2014/15. This provides a present value benefit of that deferral of between $21.7 million and $24.6 million for the range of discount rates and this, in addition to the Queensland one year deferral benefits negotiated at $2.7m, represents the principal network benefit offered by Directlink.

As an alternative to valuing the Queensland deferrals using the negotiated contract terms, the present value of the deferrals have also been calculated and are presented in the following table.

Table 3-17 – Alternative 5 Present Value Costs Qld Deferrals – 2005 dollars ($m)

Qld Deferrals	7%	9%	11%
Without Directlink (Alt 0, 1 or 2)	$49.88	$49.88	$49.88
With Directlink (Alt 0, 1 or 2)	$46.61	$45.76	$44.94
Transmission Deferral Benefit of Directlink	$3.26	$4.12	$4.94

The benefits of a one year deferral of the Queensland augmentations based on the cash flows of those deferrals are shown in Table 3-17. These benefits apply to Alternatives 0, 1 and 2. Note that these benefits are currently incorporated into a separate commercial agreement between DJV and Powerlink.

In relation to the transfer capabilities which underpin the Directlink service offering and those of the Alternative solutions, the following table summarises capacity limits:

Table 3-18 – Alternatives 5
Power Transfer Limits (Peak Load Conditions)

	QNI North	QNI South	Directlink North	Directlink South
High Growth	250	950	0	0
Medium Growth	300	950	0	0
Low Growth	350	950	0	0

Note – limits remain the same across years for Alternative 5.

Table 3-19 – Alternatives 0, 1 and 2
Power Transfer Limits (High Growth Scenario - Peak Load Conditions)

	QNI North	QNI South	Directlink North	Directlink South
2005/06	118	950	132	84
2006/07	120	950	130	142
2007/08	123	950	127	142
2008/09	125	950	125	142
2009/10	128	950	122	142
2010/11	130	950	120	142
2011/12	134	950	116	138
2012/13	137	950	113	136
2013/14	138	950	112	133
2014/15	140	950	110	130

Table 3-20 – Alternatives 0, 1 and 2
Power Transfer Limits (Medium Growth Scenario - Peak Load Conditions)

	QNI North	QNI South	Directlink North	Directlink South
2005/06	167	950	133	87
2006/07	169	950	131	142
2007/08	171	950	129	142
2008/09	174	950	126	142
2009/10	176	950	124	142
2010/11	179	950	121	142
2011/12	182	950	118	142
2012/13	185	950	115	138
2013/14	187	950	113	135
2014/15	188	950	112	132

Table 3-21 – Alternatives 0, 1 and 2
Power Transfer Limits (Low Growth Scenario - Peak Load Conditions)

	QNI North	QNI South	Directlink North	Directlink South
2005/06	217	950	133	89
2006/07	219	950	131	142
2007/08	221	950	129	142

2008/09	223	950	127	142
2009/10	226	950	124	142
2010/11	229	950	121	142
2011/12	232	950	118	142
2012/13	235	950	115	140
2013/14	236	950	114	137
2014/15	238	950	112	134

Table 3-22 – Alternative 3
Power Transfer Limits (High Growth Scenario - Peak Load Conditions)

	QNI North	QNI South	Directlink North	Directlink South
2005/06	112	800	138	87
2006/07	115	800	135	148
2007/08	117	800	133	148
2008/09	120	800	130	148
2009/10	123	800	127	148
2010/11	125	800	125	148
2011/12	129	800	121	144
2012/13	132	800	118	142
2013/14	134	800	116	139
2014/15	135	800	115	136

Table 3-23 – Alternative 3
Power Transfer Limits (Medium Growth Scenario - Peak Load Conditions)

	QNI North	QNI South	Directlink North	Directlink South
2005/06	161	800	139	91
2006/07	163	800	137	148
2007/08	166	800	134	148
2008/09	168	800	132	148
2009/10	171	800	129	148
2010/11	174	800	126	148
2011/12	177	800	123	148
2012/13	180	800	120	144
2013/14	182	800	118	141
2014/15	183	800	117	138

Table 3-24 – Alternative 3
Power Transfer Limits (Low Growth Scenario - Peak Load Conditions)

	QNI North	QNI South	Directlink North	Directlink South
2005/06	211	800	139	93
2006/07	213	800	137	148
2007/08	216	800	134	148
2008/09	218	800	132	148
2009/10	221	800	129	148
2010/11	223	800	127	148
2011/12	227	800	123	148
2012/13	230	800	120	146

2013/14	231	800	119	143
2014/15	233	800	117	140

The above tables show the maximum transfer capabilities for each year of the deferral period of the NSW and Qld augmentations.

In addition, for Alternative 3, medium and high load growth scenarios the outage of a 110kV Terranora line can lead to overloading on the remaining service for a net transfer of 300MW north and an outage of the Coffs Harbour to Armidale 330kV line (refer table 4.3 of the BRW report). For the medium load growth scenario this point is reached in 2009/10.

The tables highlight the change in northerly transfer capabilities as load growth in northern NSW changes. This is due to thermal constraints on the 330 KV lines south of Armidale and Tamworth.

For Alternative 3, southern flows over QNI are limited to 800MW and the reducing capacity of Directlink reduces total transfer capacity below 950MW.

Alternative 5 relates to the transfer capabilities of QNI only.

4. SERVICE STANDARDS

4.1 INTRODUCTION

As part of the overall review of the DJV application, the Commission has requested PB Associates to carry out a review of the DJV's proposed service standards in accordance with the requirements of the National Electricity Code and the Commission's Service Standards Guidelines[83]. In considering recommendations on appropriate service standards and performance targets PB Associates has been requested to review Directlink's historical performance and/or other benchmarks or factors that is deemed appropriate. Such service standards are not to be limited to those of the Commission's Service Standards Guidelines.

4.2 REVIEW BASIS

In carrying out this part of the review PB Associates has examined the original DJV application, their revised application and a supplementary letter to the Commission that provides further information on a proposed performance incentive scheme[84] **("Proposed Incentive Scheme Submission")**; reviewed the supporting information provided; discussed with DJV specific aspects of Directlink's operating characteristics, reviewed an external study on HVDC link performance comparisons and considered the Murraylink decision.

PB Associates notes that in reviewing the service standards it has relied extensively on information provided to PB Associates by the DJV. PB Associates has not undertaken a detailed audit to confirm all of the data collection processes or verify the authenticity of all of the data provided by the DJV.

4.3 CODE REQUIREMENTS

The Code requires that, in setting the transmission revenue cap, the Commission is to have regard to the service standards referred to in the Code (clause 6.2.4 (c)(2)) and any other standards imposed on the network by agreement with the relevant network users.

Clause 5.2.3 (b) and Schedule 5.1 of the Code specify the minimum quality of supply to be achieved by the networks. Networks are required to comply with the service standards specified in schedule 5.1 or in a connection agreement. If a connection agreement adversely affects any third party users, then it would be superseded by Schedule 5.1.

Schedule 5.1 outlines the planning, design and operating criteria that a network must achieve. Clause 4.4.2 of the Code defines "satisfactory operating state." Essentially the system is considered to be in a satisfactory operating state when the service standard indicators in Schedule 5.1 are met or exceeded.

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

[84] Directlink Joint Venture*, Letter to ACCC: re Application for Conversion and to a Prescribed Service and a Maximum Allowable Revenue (and Attachments 1 through 4)*, dated 9 November 2004.

4.4 SKM SERVICE STANDARD REVIEW

The Commission previously engaged Sinclair Knight Merz (SKM) to assist in considering the establishment of the Service Standard Guidelines. In particular, SKM was required to develop a range of measures and targets for each TNSP.

The initial performance measures recommended by SKM in its final report[85] for inclusion in the TNSP Performance Incentive schemes were:

- Circuit Availability;
- Loss of Supply Event Frequency Index;
- Average Outage Duration;
- Minutes Constrained - Intra-regional and
- Minutes Constrained – Inter-regional.

4.5 SERVICE STANDARD GUIDELINES

Following consideration of the SKM report and submissions from various interested parties the Commission has established its Service Standard Guidelines which form the basis for its considerations of performance incentives for all TNSPs to maintain or improve their service quality. In establishing the Service Standard Guidelines the Commission endorsed the performance measures recommended by SKM.

More specifically the Commission refers to the following performance measures in the Service Standard Guidelines:

- circuit availability;
- average outage duration;
- frequency of 'off-supply' events;
- inter-regional constraints; and
- intra-regional constraints.

The Murraylink decision is consistent with the principles espoused in the Service Standard Guidelines albeit that only one of the performance measures (circuit availability) was considered relevant for a single circuit HVDC link interconnector. Consistent with the Murraylink decision PB Associates is of the view that the use of circuit availability as the single primary measure of performance is sufficient to capture the value of the services capable of being supplied by the Directlink asset.

The Commission's Service Standard Guidelines propose to initially cap the financial incentives available from achieving performance targets to ±1 per cent of the TNSP's revenue cap. This cap level is consistent with the Commission's recent TNSP determinations.

However, PB Associates believes that this form of capped incentive arrangement may not provide a sufficient enough performance incentive for historically less reliable network support services. Following on from the original DJV submission, PB Associates had

[85] ACCC TNSP Service Provider Standards – SKM – November 2002

requested historical availability figures from the DJV as PB Associates was aware of a number of problems associated with the historical reliability of the Directlink Asset operating as a Market Network Service. In their Proposed Incentive Scheme Submission, the DJV has provided some historical reliability figures for the period January 2003 through to November 2004 on a confidential basis.

While this period only represents a subset of the operating history of the asset there have been a number of occasions where only one of the three parallel legs has been in operation.

PB Associates is of the view that since much of the value of the Directlink asset as a regulated asset revolves around the deferral of the 330 kV Dumaresq to Lismore line then the deferral benefit component should be rewarded on the basis of the reliable capacity available for deferment. Thus if only a percentage of the nominal capacity used to calculate the deferral and other benefits associated with the application of the regulatory test is reliably available over an annual period then an argument can be mounted that the regulated income should be reduced on the basis of that percentage on a pro rata or other service related and explicitly calculated basis.

4.6 DIRECTLINK OVERVIEW

The Directlink infrastructure has been described in detail earlier in this report.

For the purposes of considering the Directlink application, external network constraints can limit the transfer capability under certain transmission system operating scenarios. These constraints are associated with the transmission networks and, in the view of PB Associates, are not directly relevant to consideration of the service levels provided by DJV in its operation and management of Directlink.

4.7 DIRECTLINK RELIABILITY

In its original application the DJV has claimed that the circuit service availability over the previous 3 years is not relevant in that it has operated as a market network service provider during that period of time. PB Associates believes that historical performance does have relevance in considerations for establishing an appropriate performance incentive scheme and addresses this aspect in later parts of this section 4 of the report.

In the Service Standard Guidelines the Commission indicates that it would use the TNSP's performance history to set performance targets. In the event that this performance history is not available the Commission will use other appropriate information to set targets. Such information may include:

- an appropriate benchmark to set performance targets and incentives for each performance measure;
- apply other methods to set performance targets and incentives; and
- consider the TNSP's request to include additional and/or amendments to performance measures when it makes its transmission revenue cap decision.

As mentioned in section 4.5 the DJV has now provided some historical availability figures and have further provided information indicating that the DJV is planning to implement a number of measures to improve the reliability of the Directlink asset. This may mean that historical performance may not be an appropriate basis upon which to base future performance targets. However, the availability statistics recently provided by Directlink incorporate information that assists in gaining an understanding of the reliability issues with which the DJV, TransGrid, Powerlink, Country Energy and NEMMCO may be faced if the Directlink Asset becomes a prescribed service.

In the absence of using historical availability performance figures, PB Associates believes that the measures incorporated in the Murraylink decision become relevant factors for the assessment of the Directlink performance measures. PB Associates believes that the improved reliability plans being implemented by Directlink are yet to be proven and the DJV should be incentivised to operate in accordance with the claimed improved reliability or a reliability commensurate with Murraylink as this very reliability is central to the Directlink Asset being able to provide network support services sufficient to defer major transmission augmentation works. Such services are the key basis for the formulation of the DJV's (and PB Associates') application of the Regulatory Test.

PB Associates recognises that Murraylink uses a more advanced design than that used on Directlink and other HVDC Light® projects and that the design of Directlink incorporates, in effect, three parallel HV DC links compared to Murraylink's single circuit configuration.

4.8 DIRECTLINK SERVICE STANDARD PROPOSAL

In their applications to the Commission, the DJV proposes a performance incentive scheme that the DJV believes is consistent with the Commission's Service Standard Guidelines. They discuss each of the five service standards incorporated in the Service Standard Guidelines, viz:

1. Circuit availability;
2. Loss of supply event frequency index;
3. Average outage duration;
4. Minutes constrained – intra-regional and
5. Minutes constrained – inter-regional.

The measures developed by SKM for TNSP Performance Incentive scheme were considered primarily to cover the situation where TNSPs operate meshed network systems connecting generation to loads. They were not designed to apply to what is ostensibly a single dedicated circuit such as the Directlink asset. The performance measures used for Directlink in any revenue cap decision need to take account of the special characteristics of the asset, particularly the fact that it is in effect a single circuit (including three parallel HV DC links over most of its length), which is not used directly to supply customer load.

Consistent with the Murraylink determination, the DJV application considers that, as an interregional transmission link only the circuit availability performance measure is relevant. PB Associates believes that this approach is appropriate.

In the Murraylink determination the circuit availability takes into account both the capacity unavailable and the duration of any unavailability. The availability index is therefore really a measure of equivalent energy unavailability and the approach proposed is consistent with the way availability of HVDC links are measured internationally, for example using the CIGRÉ protocol discussed in Section 4.9

The Commission's Service Standard Guidelines identify the following possible sub-measures for circuit availability:

- Transmission circuit availability (critical circuits)
- Transmission circuit availability (non-critical circuits)

- Transmission circuit availability (peak periods)
- Transmission circuit availability (intermediate periods)
- Transmission lines
- Transmission transformers
- Transmission reactive

Peak system periods are defined as 7:00am to 10:00pm weekdays or as otherwise defined by the TNSP/NEMMCO. Off peak is defined as being at all other times. Intermediate periods could also be defined along with seasonal periods although none were recommended by SKM in its final report and none have been applied to date by the Commission.

In the case of Directlink, the asset is a single circuit (although including three parallel links) and as such PB Associates believes that the circuit should be considered as a single circuit for availability calculation purposes, consistent with the CIGRÉ protocol.

PB Associates recommends that Directlink's circuit availability should be subdivided into planned and forced availability consistent with the Murraylink decision.

In their Proposed Incentive Scheme Submission, the DJV has defined the annual duration of planned outages, which could be used as the basis of a planned availability service measure. The DJV has also provided information on forced outages broken down into peak and off-peak periods. In their original submission the DJV had based their availability figures on a definition that was not consistent with the CIGRÉ protocol and as such one that was inconsistent with that utilised in assessments associated with the Murraylink determination.

The effect of using the original definition proposed by the DJV compared to that used in the Murraylink determination can be clearly seen when considering availability calculations on historical performance data. The DJV provided historical information on the Directlink assets availability during the period from January 2003 to November 2004. Based on the original DJV definition of availability this historical performance would reflect an availability of 99.49% whereas a definition consistent with the CIGRÉ protocol would provide an availability of 80.24%. Clearly there is a considerable difference between the two figures and supports PB Associates' recommendations to use a definition that is consistent with the Murraylink (and CIGRÉ) definition.

Discussion on PB Associates' proposed performance measurement regime for Directlink, based on the above general considerations is presented in Section 4.10.1.

4.9 CIGRÉ REPORTING PROTOCOL

In their application, the DJV propose to use the CIGRÉ protocol as the starting point for the calculation of the availability for the Directlink asset[86]. This scheme is widely used for monitoring and reporting availability of HVDC transmission schemes. Companies report on a voluntarily basis their energy transfer, utilisation, availability, unavailability due to scheduled and forced outages, forced outages, commutation start failures and forced outage severity.

CIGRÉ (International Conference on Large Electric Systems) is a permanent non-governmental and non profit-making International Association based in France. It was

[86] Protocol for reporting the Operational Performance of HVDC Transmission Systems CIGRÉ Working Group 14-04 1997.

founded in 1921 and aims to facilitate and develop the exchange of engineering knowledge and information, between engineering personnel and technical specialists in all countries as regards generation and high voltage transmission of electricity.

CIGRÉ has established a number of Study Groups that focus on particular aspects of generation and high voltage transmission of electricity. One group, HVDC links (Study Committee 14), considers the planning, design, performance, control, protection, construction and testing of converter stations, i.e. the converting equipment itself and also the equipment associated with HVDC links. A Working Group (14.04) within Study Committee 14 was established to collect information on all HVDC transmission systems in commercial service.

Performance of HVDC links is collected annually (since 1995) and the results are summarised every two years in a CIGRÉ conference paper. This information can be used to compare the performance of different HVDC links although, if used in this way, care needs to be taken to ensure different technologies and installation methods are taken into account. Links with solid-state power electronic based valves (as in the case of Directlink) are more reliable than those with mercury valve converters. The same applies to links with underground cables (as in the case of Directlink) compared with those with an overhead line between the converters.

The CIGRÉ protocol measures availability in terms of capacity unavailable and the duration of this unavailability to determine energy unavailability. For example if over a year Directlink had 50 hours of planned outages when the full capacity was unavailable, 4 forced outages of 30 hours where full capacity was unavailable and 2 forced outages of 25 hours where 50% capacity was available, then the total circuit energy unavailability would be calculated as follows:

$$100 \times (50 + (4 \times 30) + (2 \times 25 \times 0.5))/(365 \times 24) = 2.23\% \text{ for the year}$$

In their original application the DJV has implicitly considered that the Directlink asset is fully available if one or more of the three parallel HVDC links comprising the Directlink asset are available. This approach is not consistent with the CIGRE reporting protocol. In the Murraylink application the MTC indicated that the number of duplicate in service components affecting capacity is minimal resulting in Murraylink most likely either being available at full capacity or zero capacity and not at part capacity. In the case of Directlink part capacity is a very credible situation and this can significantly influence the calculation of availability figures (as evidenced by the historical calculation results presented in section 4.8 above).

The CIGRÉ reporting protocol is compatible with the Commission's principles and PB Associates supports the adoption of this protocol for Directlink's Performance Incentive.

4.10 PROPOSED SERVICE MEASURES FOR DIRECTLINK

4.10.1 Recommended measures

The recommended service measures for Directlink are:

- planned circuit energy unavailability;
- forced outage circuit energy unavailability in peak periods and
- forced outage circuit energy unavailability in off-peak periods.

CIGRÉ reporting protocol defines a scheduled outage (planned) as one that is planned or which can be deferred until a suitable time. These are outages, which can be planned well in advance, primarily for preventative maintenance. If a scheduled outage is extended due to additional work, which would have otherwise necessitated a forced outage, then the excess period is counted as a forced outage.

The outage planning notification period would normally be negotiated with NEMMCO in line with practices adopted for other transmission lines. However NEMMCO most frequently deals with requests for maintenance outages of network elements that have short recall periods. This would not be the case for Directlink, with outages of 3 days setting the benchmark, and so NEMMCO's ability to determine the probable network loading over a number of days will present a challenge for scheduling of maintenance in summer and winter periods.

Forced outage availability is split into peak and off-peak to reflect the effect that the unavailability of Directlink would have on other market participants. This would also enable forced outages in peak periods to have a financial impact in the Performance Incentive scheme higher than those in off-peak periods. SKM in its final report define the peak period as being from 7:00am to 10:00pm weekdays and this definition was also used in the Murraylink decision.

PB Associates believes that there is a need for clarification as to the reference time for the purpose of determining peak and off peak periods especially for interconnectors that may operate between regions in different time zones. In their application the DJV has proposed a peak period definition of 7.00 am to 10.00 pm weekdays excluding public holidays in Queensland and New South Wales. In the Murraylink decision the peak period was implicitly taken to not exclude public holidays.

PB Associates recommends that a definition of peak consistent with the DJV application is relevant for the purposes of determining the relevant peak and off peak periods as this is generally reflective of the periods in which peak loads occur and the prescribed service is likely to add maximum value. However, PB Associates recommends that the reference should only exclude NSW public holidays and should explicitly be referenced to Eastern Standard Time as it is consistent with Market conventions. In summary PB Associates recommends a peak definition of 7.00 am to 10.00 pm Eastern Standard Time on working weekdays in New South Wales. This time frame would be used to determine forced outage unavailability in peak and off-peak periods.

Availability performance would be determined using the capacity available to NEMMCO offered by Directlink. Failure of equipment not needed for power transmission, which does not result in a reduction of available Directlink capacity, should not impact on the service measure. Planned availability performance is not split into peak and off-peak as the outage periods would normally be negotiated with NEMMCO and as such there should be a reasonably high correlation of planned outage timing with lighter load periods with outages planned to minimise the overall impact on the operation of the grid.

It is noted that in the original application, the DJV had proposed a definition for "Availability" which states "the Circuit is Available if it is capable of providing real power flows". As discussed a number of times previously PB Associates believes that such a definition is not consistent with the CIGRÉ reporting protocol in that, under the proposed DJV definition, even if the asset could only transfer 1 MW of power then the circuit could be deemed to be available.

The DJV application claims that Directlink asset provides network support services that are available to the point of deferring planned network augmentations. The level of support provided would be heavily dependent on how much capacity Directlink has available, in terms of MW and MVAr. For example, should one of the three parallel HVDC Light® links be out of service due to either a planned or forced outage, the active power capability is nominally reduced to 120MW and subsequently only 120MW would be available for network support. Similarly, under these conditions, the amount of reactive power available to provide the reactive power or AC voltage control benefits claimed by the DJV would also be proportionately reduced. In these cases, the effectiveness of Directlink to provide these benefits would be reduced. The situation would be worsened if two of the three parallel HVDC Light® links were out of service.

In the case of an outage of one of the HVDC Light® parallel links, even though Directlink has retained some active and reactive power capability, the potential benefits delivered by the Directlink asset are significantly reduced.

PB Associates contends that any performance measure be able to not only evaluate when the whole Directlink facility is out of service, but also when one or more of the individual parallel HVDC Light® links are also out of service. The methodology originally proposed by the DJV, whereby a "binary" type performance measure is used, means that the availability would be 100%, even if only one HVDC Light® link is in service (with reduced active power capability of 60MW, and therefore reduced effectiveness of the network support services) and 0% only when all three HVDC Light® links are out of service. PB Associates believes this level of performance would not truly reflect Directlink's capacity performance in providing the nominated network benefits, in particular network contingency support, active power support and reactive power support (or AC voltage control).

In their Proposed Incentive Scheme submission the DJV has revised their original application definition of Directlink being available from ”the circuit is available if it is capable of providing real power flows” to “the circuit is available in proportion to the extent to which one, two or three of its unit are available”. PB Associates believes that the revised definition is more in keeping with the CIGRE reporting protocol but believes that it could be further refined to indicate that “the availability is the proportion of total available capacity of the asset in relation to the nominal capacity of the asset” with the nominal capacity being the capacity used to determine the network support capability of the asset.

Any formula used to demonstrate circuit availability should reflect any reduction of available capacity in proportion to the total available capacity. This approach is consistent with the CIGRE reporting protocol. For example, should one HVDC Light® link be out of service for an entire year, the performance measure should be 66.7%. Further if only 50% of capacity was available on one of the three links, with the other two links fully available the available capacity would reflect 83.33% availability

4.11 FORCE MAJEURE

In the Commission’s Service Standard Guidelines the following definition of Force Majeure was incorporated:

“For the purpose of applying the service standards performance-incentive scheme, ‘force majeure events’ means any event, act or circumstance or combination of events, acts and circumstances which (despite the observance of good electricity industry practice) is beyond the reasonable control of the party affected by any such event, which may include, without limitation, the following:

- fire, lightning, explosion, flood, earthquake, storm, cyclone, action of the elements, riots, civil commotion, malicious damage, natural disaster, sabotage, act of a public enemy, act of God, war (declared or undeclared), blockage, revolution, radioactive contamination, toxic or dangerous chemical contamination or force of nature

- action or inaction by a court, government agency (including denial, refusal or failure to grant any authorisation, despite timely best endeavour to obtain same)

- strikes, lockouts, industrial and/or labour disputes and/or difficulties, work bans, blockades or picketing

- acts or omissions (other than a failure to pay money) of a party other than the TNSP which party either is connected to or uses the high voltage grid or is directly connected to or uses a system for the supply of electricity which in turn is connected to the high voltage grid

- where those acts or omissions affect the ability of the TNSP to perform its obligations under the service standard by virtue of that direct or indirect connection to or use of the high voltage grid.

In determining what force majeure events should be 'Excluded force majeure events' the ACCC will consider the following:

- was the event unforeseeable and its impact extraordinary, uncontrollable and not manageable?

- does the event occur frequently? If so how did the impact of the particular event differ?

- could the TNSP, in practice, have prevented the impact (not necessarily the event itself)?

- could the TNSP have effectively reduced the impact of the event by adopting better practices?

In the Murraylink decision the Commission considered a very similar definition although it did not specifically define considerations for what could be excluded force majeure events.

In their application the DJV has proposed that Excluded Events include any event that causes the Directlink asset to not be available as a result of:

- a fault, other event or capacity constraint on a Third Party System;

- a direction from NEMMCO, NECA or other authority;

- works by TransGrid, Country Energy or Powerlink;

- damage to cables or other equipment from third party actions that the Commission believes the DJV's best endeavours were unable to prevent; or

- Force Majeure Events

Further the DJV has specifically included Force Majeure events of:

- The loss or damage to 11 or more control or secondary cables;

- The loss or damage to two or more transformers and capacitor banks, either single or three phase, connected to a bus; or

- The loss or damage to a transformer, capacitor bank, or reactor which loss is not repairable on site according to normal practices.

The exclusion of capacity reductions due to events on Third Party systems is incorporated into the Service Standard Guidelines and presumably this item would also cover the exclusion for works carried out by TransGrid, Country Energy and Powerlink. A direction by a relevant authority would be an excluded event provided that such direction is not as a result of a failure by the DJV to operate the asset in accordance with relevant statutory and regulatory requirements and as such PB Associates believe should not be a specifically excluded event and the DJV should be required to justify the exclusion on a case by case basis.

Similarly damage to cables or other equipment by a third party would be an excluded event provided that the DJV has installed and operated the cable utilising good electricity industry practice and given the provision should not be an excluded event unless justified to the Commission's satisfaction.

In terms of the specific Force Majeure events nominated, PB Associates does not believe that specific events of the nature provided in the Directlink application should be automatically defined as Force Majeure events. Applications for exclusion on these grounds should be made on a case by case basis as required under the annual compliance reporting requirements of the Service Standard Guidelines. In the Murraylink determination the Commission did not specifically reference exclusion in relation to particular events occurring.

In a situation where Directlink wanted a particular event excluded due to Force Majeure, PB Associates believes that the DJV would also need to satisfy the Commission that any requirements of the Code not covered within the Service Standard Guidelines were complied with.

4.12 DIRECTLINK BENCHMARKS

4.12.1 Proposed Directlink Benchmarks

In their Proposed Incentive Scheme Submission, the DJV has forecast that each of the parallel legs of the Directlink circuit will be unavailable for 48 hours per annum due to planned outages. This would result in an annual equivalent circuit planned outage unavailability of 48 hours per annum according to the CIGRÉ reporting protocol. This is reasonably low when compared to the figures claimed by the MTC in the Murraylink application and allowed in the Murraylink decision (72 hours for planned outages). A figure of 48 hours per annum represents an equivalent planned outage availability of 99.45%.

In terms of forced outages the DJV has indicated that, given the planned maintenance schedule, it would be reasonable that Directlink's total annual equivalent outage hours for forced outages would be 67.10 hours. Given that there is an equal probability of outages being either peak or off peak, under a pro rata of annual peak to off peak hours (3780 hours peak, 4980 hours off peak), the equivalent annual peak forced outages would be 28.96 hours with equivalent annual off peak forced outages 38.15 hours. This information is consistent with the CIGRE definition for availability and represents an availability of 99.23%. The above definition makes the on peak and off peak percentages the same.

In the Murraylink assessment a total of 100.8 hours was accepted as being a reasonable benchmark for overall forced outages. This figure was then broken down into peak and off peak periods on a time weighted basis.

4.12.2 Proposed Directlink Targets

Based on the information provided by the DJV on their proposed planned outages, 48 hours per annum equivalence represents a higher planned availability in terms of the CIGRÉ reporting protocol calculations than that utilised for Murraylink (72 hours).

In terms of forced outages the DJV have indicated a proposal for 67.10 hours of forced outages compared to Murraylink's 100.8 hours.

PB Associates believes that the targets proposed by the DJV represent sufficient availability performance levels to provide the network support services claimed in their application on a reliable basis.

Consequently Table 4-1 sets out the recommended availability targets for Directlink to achieve 100% of its allowable annual revenue as proposed by the DJV.

Table 4-1 - Recommended Performance Incentives

Outage	Time (hours)	Availability	
Planned	48	0.9945	= 1-48/(365 x 24 - 28.96- 38.15)
Peak forced	28.96	0.9967	= 1-28.96/(365 x 24 - 38.15 - 48)
Off Peak forced	38.15	0.9956	= 1-38.15/(365 x 24 -28.96 - 48)
Total	**115.11**	**0.9869**	**= 1-115.10/(365 x 24)**

PB Associates agrees with the DJV's proposal for three individual performance targets rather than a single overall target which is consistent with the Murraylink determination.

PB Associates believes that the establishment of incentives about the recommended performance standards should consider penalty provisions that are not capped at 1% given the history of technical issues and high unavailability of the Directlink asset operating as an MNSP in the NEM.

In their original application the DJV had proposed capping the maximum penalty against the target service standard at 1.0% while maintaining a maximum reward incentive of 1.0% with the incentives to be applied as +/- 0.35% against both peak and off peak forced outages and 0.3% against planned outages. This is not totally consistent with the Murraylink determination where the incentives were weighted 40% (of the 1% cap) for planned outages and forced peak outages and 20% for forced off peak outages.

Whilst the Commission has previously capped all incentive schemes at +/- 1% it is clear that capping incentives does not provide a true reflection of the level of benefits delivered by an asset as compared to the benefits assumed to be provided under the application of the regulatory test.

To this end PB Associates believes that the Commission could establish an appropriate incentive scheme to be applied against the recommended performance target by applying the regulatory market benefits test against a range of reliable capacity assumptions for the relevant asset. In the case of the Directlink asset, for example, a calculation at 2/3 capacity availability would ascribe a value for the Directlink asset if one leg of the three parallel HV DC links was notionally out of service on a permanent basis. In this way a more accurate appreciation for the benefits actually delivered (or not delivered) by an asset subject to the Regulatory test could be gained and an appropriate penalty (and reward) can be calculated commensurate with actual performance.

PB Associates has reviewed the historical availability figures provided by the DJV and has calculated that 2/3 of the Directlink capacity was provided with an availability of 95.8%for the period from January 2003 through to November 2004. Although PB Associates has not carried out a rigorous analysis on the effect of this lower level of availability it is estimated that the reliable availability of only 2/3 level of capacity would reduce Directlink's deferral benefits by about one year which represent a dollar value reduction of approximately $4million.

Once the Commission has considered this aspect then PB Associates believes that further consideration could then be given to applying weightings to the three factors in establishing an overall performance incentive scheme and setting the maximum penalty targets, if any. The maximum reward targets would be set at 100% for forced outages and at an appropriate (minimum maintenance) level for planned outages. The DJV have proposed a maximum reward target availability of 100% for planned outages which may be somewhat onerous and PB Associates recommends a lower target level to make sure there are incentives for at least a prudent minimal amount of maintenance to be carried out.

PB Associates believes that a collar should be established around the target levels proposed in this section and as set out in Table 4.1 above. However PB Associates does not have sufficient information at this point it in time to justify recommending specific floor and cap levels for all of the circuit availability metrics proposed. Specifically PB Associates would require details of the minimum maintenance that is tolerable for the Directlink Units to establish a performance level in order to achieve a 1% reward incentive. Further analysis would need to be carried out on the impacts of poor reliability on the Regulatory Test outcomes in order to recommend appropriate levels in terms of both maximum penalty percentages and an associated performance floor for the maximum penalty percentages to be applied.

4.13 ADJUSTMENT OF TARGETS

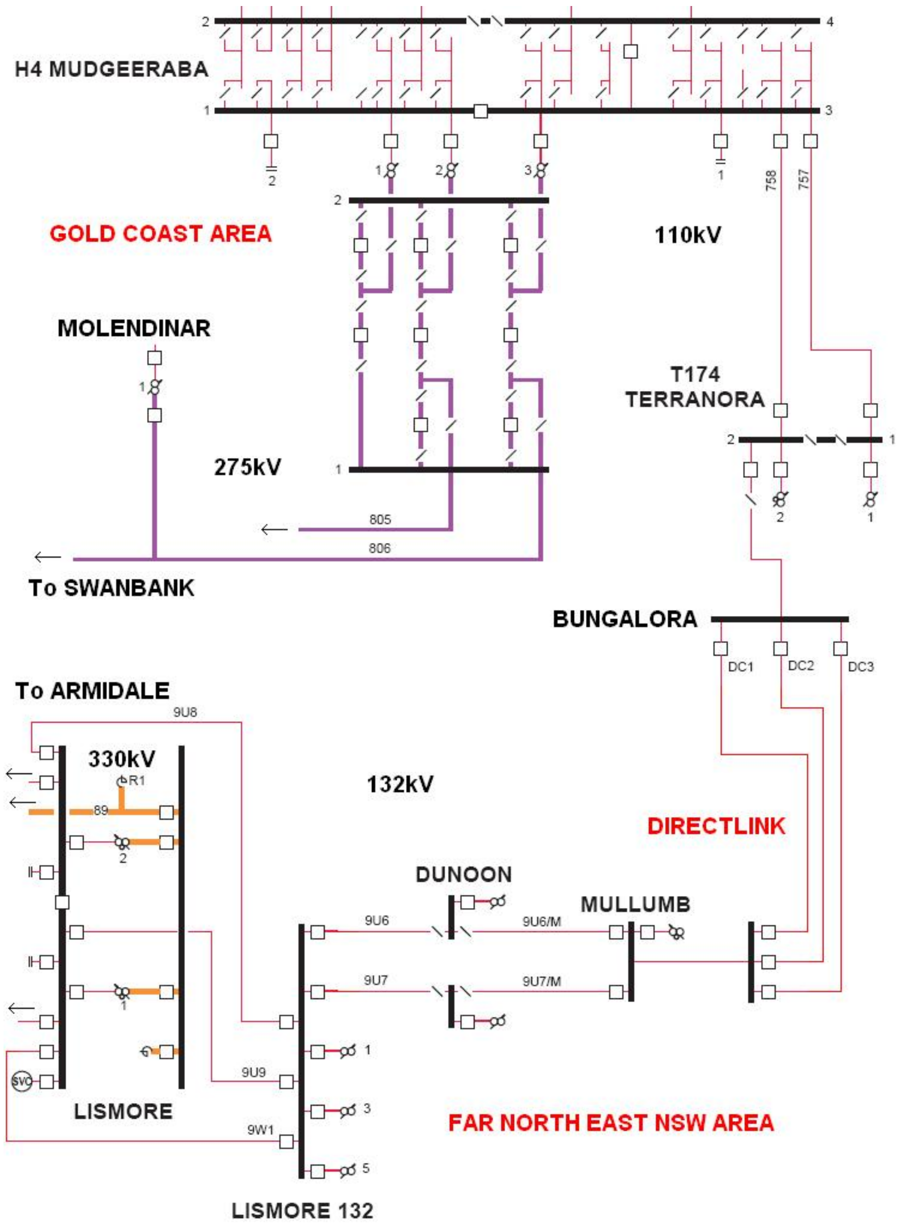
The DJV original submission proposed that the targets apply for a period of five years which is consistent with the Murraylink determination and, in the case of other TNSPs, the Performance Incentive targets were classed as interim and expected to apply for about 5 years. The targets and measures in other decisions were to be refined as further data was collected.

Given some of its historical performance issues the Directlink asset does not have operational performance sufficient to be used as a basis for establishing targets. Indeed, in their Proposed Incentive Scheme submission, the DJV has proposed targets based on anticipated effects of remedial actions to improve availability. In the case of other TNSPs, if there was no credible performance information for a measure, the measure was not used in the Performance Incentive scheme. PB Associates supports Directlink's proposal to have the performance incentive reviewed 5 years after any Commission determination takes effect.

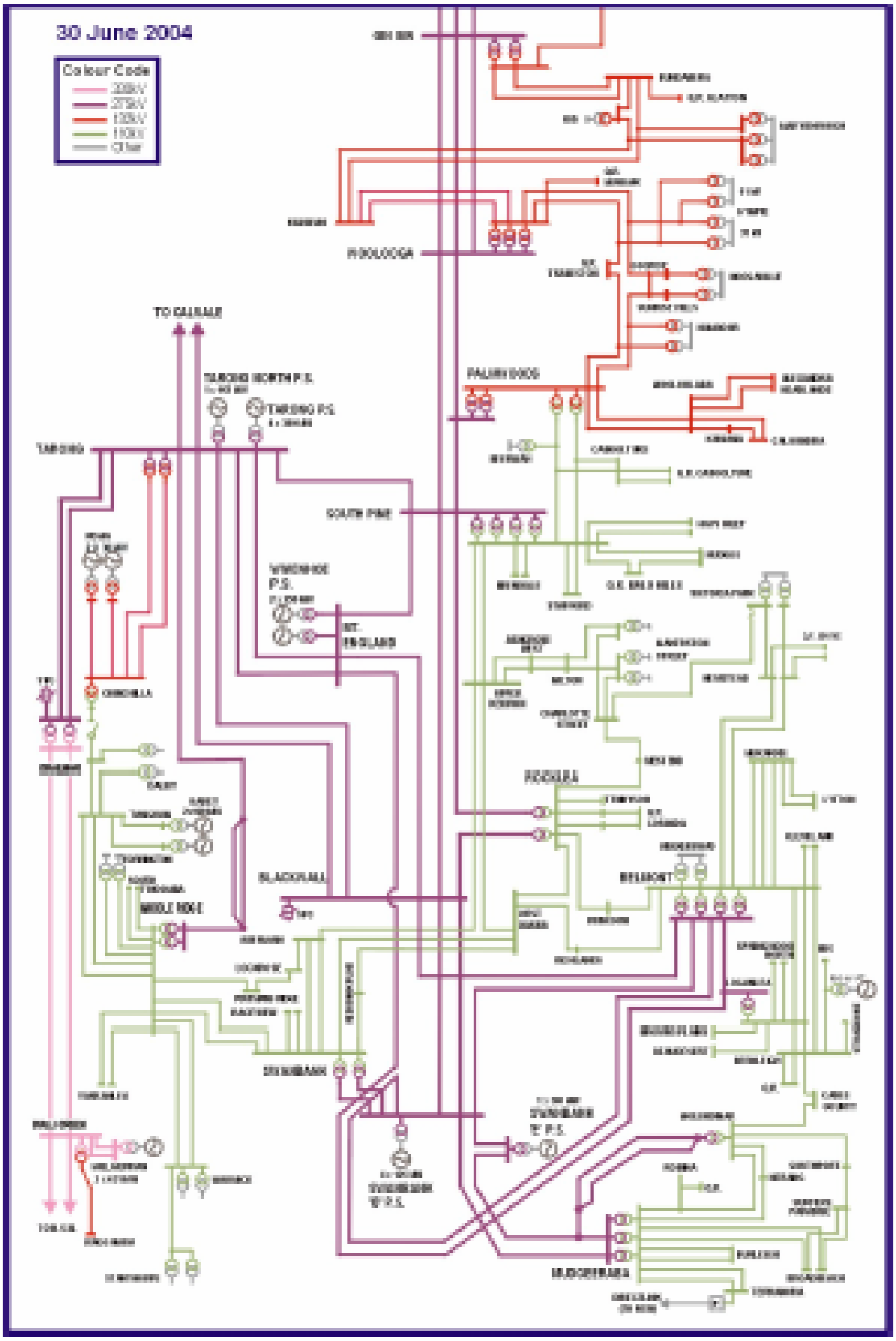
4.14 DIRECTLINK PERFORMANCE AND ALTERNATIVE 5 DEFERRAL REQUIREMENTS

PB Associates has reviewed the Directlink's outage history which was provided to the Commission by the DJV in a report dated 9 November 2004. This report indicates that the current reliability of Directlink is 95.8% availability at 120MW nominal. In order to defer the NSW augmentations of Alternative 5 as discussed in section 3.2 until 2014/15, a reliability level of at least 99% availability would be required at 120MW nominal. In determining the deferral benefits offered by Directlink, PB Associates has assumed that the reliability target of 99% availability would be achieved. PB Associates, however, agrees with the DJV's report that "in order for Directlink to achieve these levels of availability it is necessary for substantial equipment upgrades to be implemented". Clearly, therefore, the Commission would need greater assurances regarding performance levels of Directlink before accepting that the deferrals benefits could be achieved.

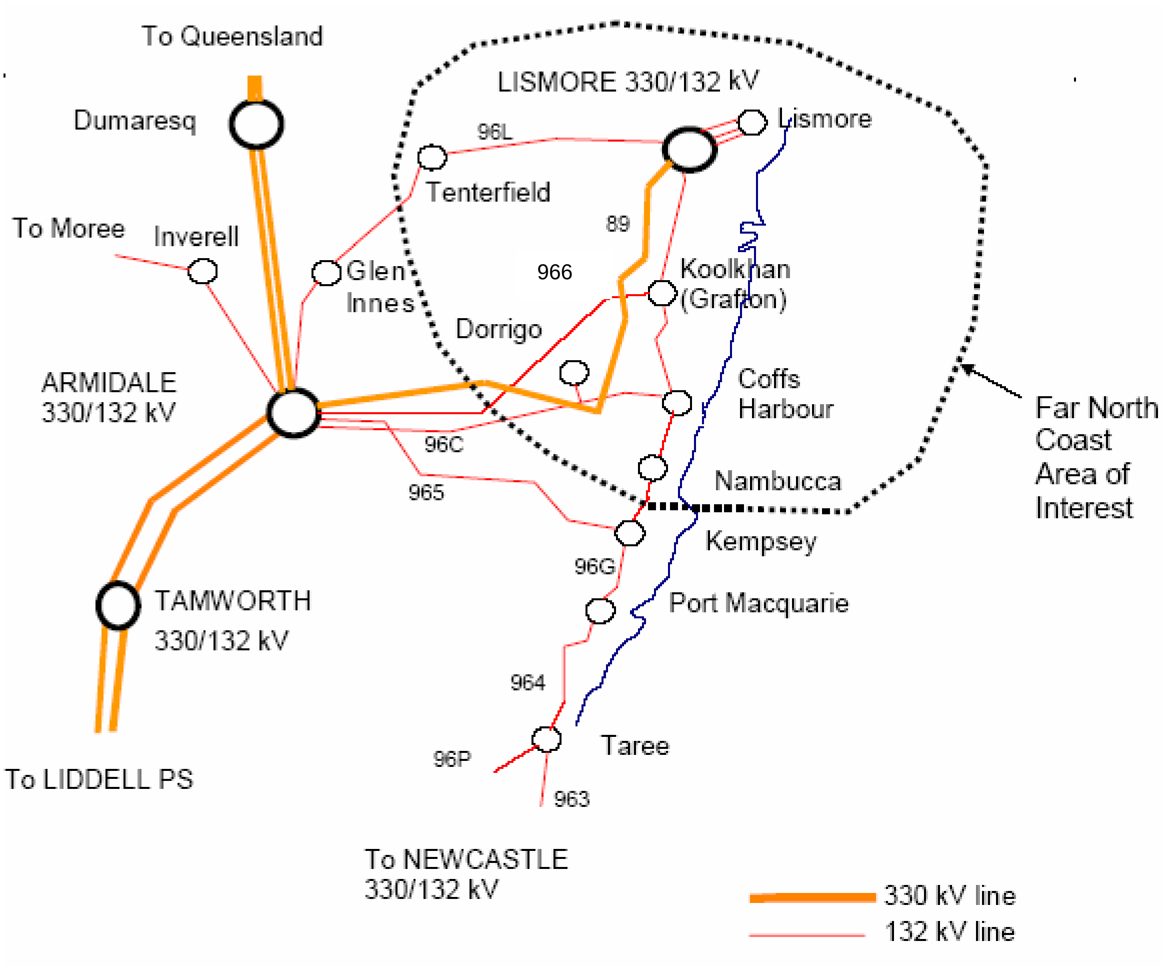
APPENDIX A
Schematic of Queensland and NSW Transmission Networks and Connected Country Energy Network System



APPENDIX B
Existing 275/132/100 kV Network – South Queensland



APPENDIX C
Existing TransGrid Transmission Supply Network – Northern New South Wales



APPENDIX D
Directlink – Historical Quarterly Export, Import Limits and Total Energy Flows

Year	Quarter	Avg import limit (MW)	Import Energy	Avg export limit (MW)	Export Energy
2000	2	-1	1019	2	422
2000	3	-43	34634	53	29407
2000	4	-22	23667	109	117120
2001	1	-50	45975	82	75452
2001	2	-90	45746	60	5217
2001	3	-92	36309	64	864
2001	4	-79	20475	67	4821
2002	1	-75	20114	70	13314
2002	2	-104	66664	46	265
2002	3	-95	46950	59	6618
2002	4	-85	36085	57	8361
2003	1	-85	51725	56	4997
2003	2	-99	64883	50	407
2003	3	-137	190495	-7	263
2003	4	-93	97452	35	3576
2004	1	-81	42479	59	1194
2004	2	-87	28737	59	1382