PB ASSOCIATES

POWERLINK REVENUE RESET

Review of Capital Expenditure, Operating and Maintenance Expenditure and Service Standards

Prepared for

AUSTRALIAN ENERGY REGULATOR

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EXECUTIVE SUMMARY

Background

Under the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for regulating revenues associated with the non-contestable elements of the transmission services provided by Powerlink Queensland (Powerlink). The AER is required to set the maximum allowed revenue (MAR) that Powerlink may earn from the provision of these regulated transmission services for the next regulatory period, which runs from 1 July 2007 to 30 June 2012.

On 3 April 2006, Powerlink submitted a Revenue Proposal to the AER. The Proposal contained Powerlink's view on the appropriate MAR, given the likely increase in demand for its services and its obligations under the NER and its Transmission Authority issued by the Queensland Government under the Queensland Electricity Act 1994.

In order to assist it make a decision on the appropriate MAR for the next regulatory period, the AER engaged Parsons Brinckerhoff Associates (PB Associates) to review Powerlink's Revenue Proposal in respect of:

- the prudency of Powerlink's actual and expected capital expenditure (capex) over the current regulatory period which runs from 1 January 2002 to 30 June 2007. This review is required because, in accordance with the requirements of the AER's Statement of Regulatory Principles, only prudent capital expenditure can be included in the opening regulatory asset base (RAB) for the next regulatory period;
- the efficiency and prudency of Powerlink's capex for the next regulatory period and the reasonableness of Powerlink's policies and procedures for delivering efficient investment outcomes;
- the efficiency of Powerlink's operational expenditure (opex) for the next regulatory period and the quality of Powerlink's policies and procedures for ensuring that only necessary and efficient opex occurs; and
- Powerlink's proposed performance incentive scheme.

This report presents the findings of PB Associates' review.

Capital Expenditure Policy and Planning

We reviewed Powerlink's capital governance framework and its capex strategies, policies and procedures to test their effectiveness and consider that they are robust and consistently applied. Overall we found the planning and implementation of Powerlink's capex to be consistent with good electricity industry practice and likely to deliver efficient investment outcomes.

We consider that the methodology used by Powerlink to categorise capital expenditure to be logical and consistent with Powerlink's mission and business strategy. However assets are classified at a relatively high level and, as a result, expenditure that other TNSPs would capitalise is treated as opex. Furthermore easements are categorised separately from the primary assets they support, and easement costs are not included in the economic evaluation of different project alternatives if the easement purchase was undertaken before the economic evaluation was completed. Where easements are purchased immediately before the project commencement, this approach has the potential to distort the selection of the most efficient project. However in this review we did not identify any projects where Powerlink's treatment of easement costs affected the selection of the most economically efficient project alternative.

We have reviewed Powerlink's planning criteria and consider them to be generally reasonable, given its obligation to comply with the NER, the Queensland Electricity Act, its Transmission Authority and the connection agreements with its customers. However when applied to the Central Queensland – North Queensland load transfer, the planning criteria appear conservative and this can advance the need for network augmentations.

Powerlink's procedures for project development are generally robust and consistent with the consultation and regulatory test requirements of the NER. Powerlink also provides an opportunity for public involvement in the development of project alternatives to large network augmentations and this is over and above the consultation requirements of the NER. This has led to Powerlink using third party provided generation as an alternative to network augmentation to a greater degree than any other transmission network service provider (TNSP) in the NEM.

Project cost estimates are underpinned by Base Planning Objects (BPOs), which are essentially unit rates for different asset types. We benchmarked some of Powerlink's key BPOs against external data and we consider the BPOs used in developing Powerlink's capex forecast to be reasonable.

Powerlink has structured and systematic governance arrangements with respect to its procurement process and we consider Powerlink is achieving reasonable procurement efficiencies.

Historic Capital Expenditure

Powerlink's RAB will be rolled forward from 1 January 2002 to 1 July 2007 by adjusting for asset additions and deletions. However, the AER's Statement of Regulatory Principles indicates that the capex over the current regulatory period will be included in the opening RAB only if it is considered prudent after an ex-post prudency review.

From 1 July 2007, it is expected that Powerlink's capex will be recognised on an as-incurred basis rather than on an as-commissioned basis. This change will result in the opening RAB for the next regulatory period including a work in progress component for the first time.

In its Revenue Proposal, Powerlink has proposed that $1,274.11 million of capex for projects that will be commissioned in the current regulatory period and $529.95 million for works that will be in progress at the end of the current regulatory period be rolled into its opening RAB for the 2007-12 period, a total of $1,804.06 million. This includes a finance during construction (FDC) component of $179.35 million. However, we found two errors in Powerlink's template spreadsheet that overestimated the revenue request by $1.42 million. After, correcting for the spreadsheet error, this means that Powerlink has proposed that $1,623.29 million (excluding FDC) of historic capital expenditure be included in the opening RAB for the next regulatory period.

We consider that the FDC proposed in Powerlink's Revenue Proposal has been overstated. However further analysis is necessary to quantify the adjustment required and this is outside the scope of our review.

In undertaking this review, we examined the project evaluation and implementation procedures used by Powerlink to develop and implement its projects and found them to be consistent with good electricity industry practice and generally well followed.

We also investigated in detail 60 of the 324 projects built or proposed to be built in the current regulatory period to ensure that Powerlink was following its project evaluation and implementation processes and procedures.

We observed the following:

- There appears to be a lack of rigour in the first stage of the project evaluation process where a long list of project alternatives is reduced on technical grounds. There are no documented criteria for technical acceptability and the rejected project alternatives (including the reasons for their rejection) are not documented.

- It was not possible to fully apply the prudency test, as set out in the AER's Statement of Regulatory Principles, to the acquisition of strategic easements. This is due to the fact that an easement will only be efficient if the line to be built on it is an efficient investment, and this cannot be determined for strategic acquisitions where the line will not be required for some years. Nevertheless we consider it good industry practice to make long term acquisitions for easements in situations where anticipated changes in land use may significantly increase the cost of future acquisition. We considered this to be the case for all the strategic easement acquisitions that we reviewed, and have recommended that these investments be included in the opening RAB.

- There is no doubt that Powerlink's demand, equipment and labour costs over the current five year regulatory period have been higher than assumed in 2001. However our analysis indicated that these increases were only partly reflected in project costs at completion and were largely absorbed by efficiency gains made by Powerlink. Had the assumptions in respect of demand and input costs that were used as the basis for the 2001 Decision turned out to be accurate, we think Powerlink's actual capex for the current regulatory period would have been significantly lower than the amount allowed in the Decision.

- For the projects reviewed, we found that some project budget overruns had occurred. These overruns were caused mainly by the cost of resolving legal disputes (over the acquisition of easements) and extensions of project scopes after initial approval had been obtained. We think Powerlink should review its project development processes and identify methodologies to determine whether it is possible to reduce the need for late scope changes. Nevertheless, we concluded that the increased expenditures in the projects that we reviewed were necessary.

Of the projects that have been, or are expected to be commissioned within the current regulatory period, we reviewed 40 projects with an expected total cost at completion of $707.30 million (excluding FDC) and recommend that $701.21 million (99.1%) of this investment to be included in the opening RAB. In reviewing these projects, we did not find any consistent or systematic problems with the approach that Powerlink adopted in evaluating or implementing the projects. Any concerns we had were specific to a particular project under review.

We also reviewed 20 projects that are not expected to be commissioned by the end of the current regulatory period and which comprised $378.99 million (excluding FDC) of the work in progress component of Powerlink's proposed opening RAB. We recommend that $265.55 million (70%) be included in the opening RAB. Our main concern was with 8 projects ($111.01 million) that had not been submitted for project approval at the time of our review. We think it unlikely that Powerlink will be able to fully achieve the proposed work in progress expenditure on these projects in the time remaining within the current regulatory period and have therefore recommended that expenditure on these projects not be included in the opening RAB unless Powerlink can demonstrate with a much higher level of certainty that the projects have been approved and that the proposed capex can and will be incurred before the beginning of the next regulatory period. It may be appropriate for Powerlink and the AER to revisit this issue prior to the issue of a final decision, when the actual capital expenditure on work in progress projects can be estimated with a higher degree of certainty.

Of the projects that we did not review, we found a group of 38 projects that were included in the probabilistic analysis of forecast capex which, on the basis of the commissioning dates used in that analysis and the assumed lead times, could require expenditure in the current regulatory period if they were to proceed. Powerlink has applied the probability weightings used in that analysis and has included this probability weighted expenditure ($7.01 million) in the work in progress component of the opening RAB. However Powerlink has no plans for expenditure on any of the 38 projects in this regulatory period and we therefore recommend that that the probability weighted expenditure not be included in the opening RAB.

However the proposed expenditure for this regulatory period for both the probability weighted projects ($7.01 million) and for the projects not yet approved ($111.01 million) should be recalculated to reflect revised commissioning dates and/or expenditure profiles and included in the forecast capex allowance.

Because we did not find any consistent or systematic errors in the projects, we consider that the full cost of the projects that were not reviewed should be rolled into the opening RAB.

On this basis we recommend that Powerlink's proposed opening RAB for the next regulatory period be adjusted as shown in the following table.

Recommended capex to be rolled into opening RAB ($m, 06/07)

Item	Historic	Work in progress	Total
Powerlink Proposal (excluding FDC)	1,144.30	480.41	1,624.71
Total Adjustments to the proposal (excluding FDC)	(7.49)	(120.42)	(127.91)
PB Associates Recommendation (excluding FDC)	1,136.81	359.99	1,496.80

Forecast Capital Expenditure

The forecast capex set out in Powerlink’s Revenue Proposal is $2.45 billion (on an as-incurred basis) for the next regulatory period. Powerlink’s proposed actual capitalisations over the current 2001-07 regulatory period are $1.27 billion and work in progress is $529.95 million.

As an outcome of our high level review of Powerlink’s forecast capex requirements over the 2007-12 regulatory period, and our more detailed review of a sample of projects, we have identified a number of areas within which we believe Powerlink has overstated its capex requirements. We recommend a reduction in forecast capex of approximately $407 million (17%) as shown in the following table.

Recommended forecast capex ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink proposal	546.30	543.02	456.10	466.49	437.32	2,449.24
Recommended reduction	-62.81	-124.48	-76.60	-60.24	-83.14	-407.37
Recommended forward capex forecast	483.49	418.54	379.50	406.25	354.18	2,041.87

Note: Figures may not add due to rounding

The main reasons for our recommended reduction in capex over the next regulatory period are:

- lower asset replacement forecasts resulting from our top down analysis;
- a Powerlink initiated review of the transmission needs into South East Queensland;
- a small number of instances where we identified reduced project scopes to meet the identified constraints;

- two instances where we consider the project timing should be deferred by one year;
- the removal of pre-payments incorporated into the expenditure profiles (S-curves);
- removal of a 2.6% risk factor applied to all projects and which, in our view, was not adequately justified; and
- a reduction in the labour escalation rates used.

In addition further adjustments will be required in conjunction with recommendations made regarding the transfer of part of the proposed WIP component of the opening RAB into forecast capex. We have been unable to fully quantify these adjustments.

Our analysis identified that the capex forecast is very sensitive to the predicted demand for electricity and we suggest that the AER should consider undertaking an additional review of Powerlink's demand forecasts to assess the accuracy of Powerlink's summer maximum demand forecasting outcomes.

We recommend that only five of the ten projects proposed by Powerlink are treated as contingent projects outside Powerlink's main ex-ante revenue cap, and that a sixth be transferred from the main capex provision to a contingent project.

In making these recommendations, we examined Powerlink's proposed demand driven capex, non-demand driven capex and asset replacement capex. We note that:

- There was a significant change in the peak summer demand forecasts in Queensland between the publication of the 2004 and the 2005 APRs, which is reflected in an increase in the 2007/08 medium 50% PoE forecast of 480 MW. This has been captured in Powerlink's Revenue Proposal, which is based on the 2005 APR demand forecasts.
- Expenditure on the network comprises approximately 96% of the total forecast capex for the next regulatory period. Load driven investment accounts for almost 60% of the network capex forecast and non-load driven investment, including replacements, accounts for the remaining 40%.
- Non-network related capex comprises approximately 4% of the total forecast capex in the next regulatory period. It includes business related expenditure for information technology (IT) systems, buildings, vehicles and tools, etc.

Our main findings are as follows:

- Powerlink has undertaken a systematic and rigorous review of a complex network, and used advanced planning techniques to capture possible capex in the review period.
- A probabilistic approach is used to forecast demand and generation driven capex requirements, including augmentations, easements and connections, which comprise approximately 60% of the total forecast capex. We consider the themes and scenarios adopted by Powerlink for its probabilistic approach to be plausible and comprehensive in nature.
- A detailed review of 18 demand driven projects was undertaken. We believe that there are a small number of projects where the scope can be reduced to meet the identified constraint and two projects where the timing could be deferred by one year. In total these adjustments would reduce Powerlink's demand forecast by approximately $147 million. On the basis that the projects we selected for review were a good representation of the entire probabilistic based forecast program, we recommend a further 4% reduction on the balance of Powerlink's demand driven network capex, since we believe that similar reduction opportunities are likely to arise in the projects not sampled.

- The M50++ theme should be removed from the forward capex allowance and treated as a contingent project to be triggered based on the commitment of a major industrial load in the Gladstone area of central Queensland. The probability weighted cost of these projects is $15.7 million ($240 million unweighted).
- A detailed review of 13 asset replacement projects was undertaken. In general, we found that asset replacement expenditures need to be increased compared with existing expenditure. However, in our view, the bottom up approach adopted by Powerlink is likely to overstate the replacement needs in the next regulatory period, although we were unable to quantify this overstatement in the projects reviewed. On the basis of a top down analysis, we consider that an asset replacement requirement of $140 million per year on average, or $700 million over the regulatory period would be a reasonable provision.
- A large portion of non-network capex is ongoing, and trended consistently with historical expenditure. We recommend that Powerlink's forecast non-network capex be included in its regulatory allowance except for a reduction in the IT capex forecast.
- Powerlink has applied a risk adjustment factor (2.6%) to all of its network projects because it often experiences actual project costs that are higher than the initial estimates. We consider that Powerlink has provided insufficient evidence to establish that a material costing risk exists and consider that it would be inefficient to include such a risk factor as part of Powerlink's forecast capex.
- In reviewing the approach adopted by Powerlink to determine generic capacitor bank costs, we consider it unnecessary to adopt a generalised locality factor, given that the final sites have been established. We recommend locality factors based on the actual site be applied and consider this is likely to reduce the overall costs as the vast majority of capacitor banks are required close to the reference capital city of Brisbane.

We consider the amended capex program is achievable and that there is still reasonable scope for Powerlink to achieve some efficiency benefits and realise these benefits over the regulatory period.

Operational Expenditure

In its Revenue Proposal for the next regulatory period, Powerlink has forecast a total requirement for controllable opex of $634.94 million (06/07 dollars), up from an expected actual expenditure of $510.49 million (nominal) over the current regulatory period.

It has derived this forecast by projecting forward its actual costs for the 2004/05 base year, taking into account expected increases in the cost of labour and materials, as well as the expanding size of the asset base, which it has forecast to increase by 30% over the next regulatory period. It has also allowed for the costs of meeting new legal requirements, mainly as a result of amendments to the Workplace Health and Safety Act 1995 and the issue by the Queensland Government of a new Vegetation Management Policy and Guidelines under the Vegetation Management Act 1999.

We recommend that the opex allowance be reduced to $573.00 million (06/07). Our recommended changes to Powerlink's controllable opex forecast are shown in the table below.

The total effect of our recommended changes is a reduction of $61.93 million (06/07) in controllable forecast opex over the five year regulatory period. If these recommendations are adopted, however, a total of $48.35 million (06/07) which is the component of operational refurbishment which we consider to be of a capital nature would need to be included in the capex forecast.

Recommended Controllable Opex Forecast ($ 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink's Forecast Controllable Opex	113,106,606	119,488,880	126,540,382	135,641,287	140,158,649	634,935,804
Changes to Labour, Material and Vegetation Management Costs	15,802	(237,696)	(523,008)	(1,808,464)	(3,187,621)	(5,740,987)
Change to Operational Refurbishment Costs	(7,288,000)	(8,922,000)	(10,443,000)	(11,135,000)	(10,563,000)	(48,351,000)
Changes to Condition Based Maintenance.	(543,502)	(1,119,274)	(1,619,197)	(2,031,255)	(2,527,416)	(7,840,644)
Recommended Controllable Opex Forecast	**105,290,906**	**109,209,910**	**113,955,177**	**120,666,568**	**123,880,612**	**573,003,173**

Source: PB Associates

We undertook our review by assessing the accuracy and robustness of the spreadsheet model used to develop the forecast opex, and by reviewing the validity of the assumptions on which the model was based. Our main findings are listed below.

- An efficient base year opex was adopted.

- The assumption of an annual average rise in labour rates consistent with the EBAs and of the order of 5.6% is reasonable for the first three years of the next regulatory period because of the current tight market for skilled tradespersons. In the final two years of the next regulatory period, we consider that the long term trend in the labour rate for skilled electrical workers in Queensland of 4.6% per annum is a better assumption.

- Recent increases in material costs have been driven by increases in commodity prices, particularly aluminium, copper and zinc. There is evidence that these prices have now peaked and prices in futures markets are trending downwards. We consider that material prices should be escalated by the consumer price index (CPI) rather than the 4% per annum assumed by Powerlink.

In making this recommendation, we note that Powerlink was a participant in the 2005 International Transmission Operations and Maintenance Study (ITOMS), which involved TNSPs from the Asia Pacific, European, North American and Scandinavian regions. The study compares at a detailed level the comparative costs of individual maintenance functions and their impact on the delivery of transmission network services. Powerlink's performance benchmarked within, or close to, the upper quartile of all participating utilities across all measures reviewed. This performance was supported by more limited benchmarking involving data provided to the AER by Australian TNSPs, which shows Powerlink to be an efficient performer relative to its Australian peers.

We believe that Powerlink's efficient operating performance is largely due to the arrangements in place with internal and external service providers for the provision of field maintenance services. For example, in the remote central and northern regions of Queensland, Powerlink uses the incumbent distribution network service provider for the provision of field maintenance services. This arrangement allows the costs of providing depot, storage and supervisory functions to be shared.

Powerlink has progressively introduced a formal and structured reliability centred maintenance program, which has had a significant and measurable impact in reducing maintenance costs in recent years.

Service Standards

Powerlink proposes to establish a performance incentive scheme that reflects the recommendations made by SKM to the ACCC in 2003 regarding the performance measures, targets and weightings that SKM considered appropriate for Powerlink. The performance measures proposed by Powerlink are:

- transmission circuit availability (for critical circuits, for non-critical circuits and for peak periods);
- frequency of off-supply events (for events exceeding 0.2 system minutes and for events exceeding 1.0 system minutes); and
- average outage duration.

Powerlink's proposal includes caps and collars that limit the amount of revenue at risk to 1% of the maximum allowed revenue. The caps and collars are symmetrical and are expressed as a weighting for each measure such that if actual performance exceeds the cap/collar, the cumulative value of the weightings place a maximum of 1% of revenue at risk for poor performance and provide for a maximum 1% bonus for out performing the targets.

Our analysis indicates that Powerlink's proposed targets for the next regulatory period are unlikely to provide a revenue neutral outcome. We therefore consider that the targets should be adjusted to take account of the more recent performance data that has been collected since the SKM recommendations were made. The recommended targets and other elements of the scheme are shown in the table below.

Recommended Performance Incentive Scheme

Measure	Unit	Weighting (%)	Max Penalty	Start Penalty	Target	Start Bonus	Max Bonus
Availability – critical elements	%	15.5	97.92	99.12	99.12	99.12	99.71
Availability - non-critical elements	%	8.5	98.19	98.52	98.52	98.52	98.85
Availability - peak hours	%	15.5	97.93	98.29	98.29	98.29	98.65
Loss of supply > 0.2 system minutes	Number	15.5	7.5	5.0	5.0	5.0	2.5
Loss of supply > 1.0 system minutes	Number	30	2.9	0.9	0.9	0.9	0
Average outage duration (capped 7 days)	Minutes	15	1,520	939	939	939	358

Source: PB Associates

In making this recommendation, we have examined the following aspects of the proposed performance incentive scheme:

- robustness of data definitions;
- soundness of the process for data collection and reporting;
- confidence in the accuracy of historical data;
- appropriateness of exclusions in historical data;

- performance measure calculation; and
- reasons for not proposing other measures.

Revised targets including information on recent performance are recommended. The weighting of each measure in the performance incentive scheme proposed by Powerlink has been assessed as appropriate. Revised collar/caps and deadbands are recommended to suit the revised targets.

1. INTRODUCTION

1.1 BACKGROUND

Under the National Electricity Rules (NER) the Australian Energy Regulator (AER) is responsible for regulating revenues associated with the non-contestable elements of the transmission services provided by Powerlink Queensland (Powerlink). The AER is required to set Powerlink's revenue cap for a five year period from 1 July 2007 to 30 June 2012 (the next regulatory period).

Powerlink submitted its *Queensland Transmission Network Revenue Proposal for the period 1 July 2007 to 30 June 2012* (Revenue Proposal) on 3 April 2006 and the AER is reviewing the proposal. As part of this review, the AER has engaged Parsons Brinckerhoff Associates (PB Associates) to advise it on the following aspects of the proposal:

- The capital expenditure (capex) during the current regulatory period (historic capex), which will form a significant component of the opening value of the regulatory asset base (RAB) for the next regulatory period;
- Capex during the next regulatory period (forecast capex);
- Operational expenditure (opex) during the next regulatory period (forecast opex);
- Service standards over the next regulatory period.

PB Associates commenced its review on 1 May 2006. The PB Associates review team, together with AER staff, visited Powerlink on 15-16 May 2006 for a conference on the Revenue Proposal. During the first day of the conference, Powerlink made a number of presentations on the background to Powerlink's operations and the approach taken to the preparation of its Revenue Proposal. On the second day there was a series of workshops, which provided an opportunity for PB Associates to scrutinise various aspects of the proposal in greater detail.

Following these workshops, Powerlink has provided PB Associates with further background information relevant to its Revenue Proposal and PB Associates revisited Powerlink for more intensive discussions on key aspects of the proposal. We have also examined and relied on further information provided to us by Powerlink on the analysis undertaken to develop the proposal.

We are grateful for the assistance provided to us by Powerlink staff during the course of the review. They have unfailingly responded to our often demanding requests for information in a timely manner.

This report presents the results of our review.

Chapters 2 to 4 of the report cover capex. Chapter 2 overviews the policies and procedures in place to plan and manage capex and is generally applicable to both historic and forecast capex. Chapter 3 covers historic capex while forecast capex is reviewed in Chapter 4.

Chapter 5 covers Powerlink's forecast opex for the next regulatory period.

Chapter 6 discusses Powerlink's performance measures, targets and other elements of a performance incentive scheme.

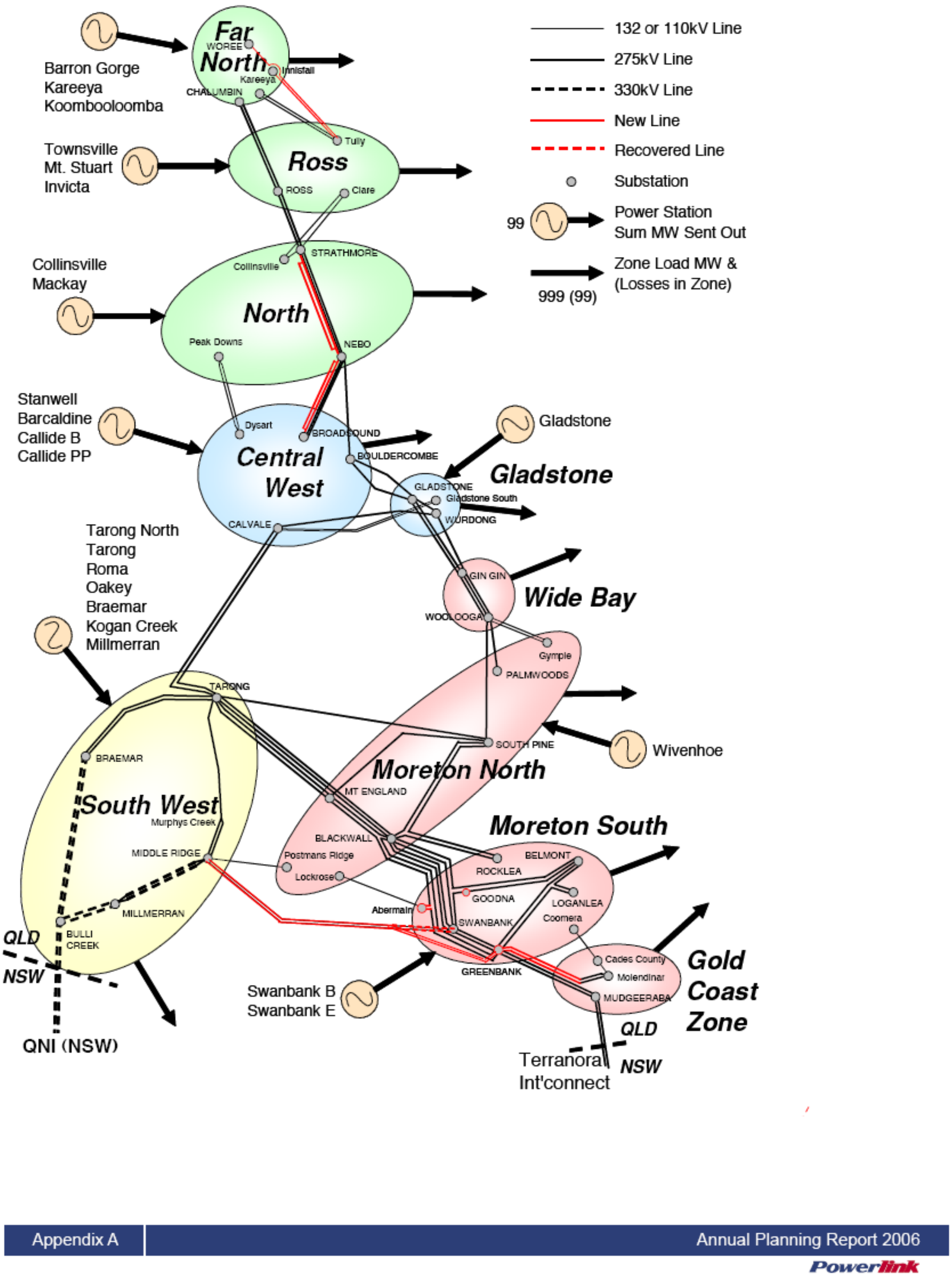
1.2 OVERVIEW OF THE POWERLINK NETWORK

The Queensland transmission network stretches approximately 1700 km from Cairns in the north to Mudgeeraba in the south. This system is constructed and operated at 275 kV, with 110 kV and 132 kV networks providing transmission in local zones and providing limited backup to the 275 kV grid. In addition, 330 kV lines link Millmerran, Middle Ridge and Braemar to the New South Wales (NSW) border near Texas. A high level systemised overview of the network, as presented in Powerlink's annual planning report (APR), is shown in Figure 1-1.

It can be seen from Figure 1-1 that the network is subdivided into four regions: North Queensland (NQ), Central Queensland (CQ), South East Queensland (SEQ), and South West Queensland (SWQ) with each region interconnected to neighbouring regions generally by 275 kV interconnectors. Each region (except SWQ) is then further subdivided into zones which may be interconnected by lower capacity 132 kV and 110 kV lines operating in parallel to the 275 kV backbone network. There are ten zones in all.

The Queensland distribution network service providers (DNSPs), Energex and Ergon Energy own 132 kV and 110 kV subtransmission networks that connect to the Powerlink network. Powerlink plans the development of its network jointly with both Energex and Ergon with the objective of delivering the lowest overall cost to consumers, consistent with meeting legal and regulatory obligations.

Figure 1-1: Overview of the Powerlink Transmission System.



2. CAPITAL EXPENDITURE JUSTIFICATION AND PLANNING

2.1 INTRODUCTION

In this Chapter we describe and evaluate Powerlink's internal organisation, policies and procedures as they relate to the ongoing development of its network and the management of its capex. The purpose of the evaluation is to confirm that Powerlink's capex justification and planning processes are effective in ensuring that its capex is sufficient to meet Powerlink's legal and regulatory obligations but, at the same time, ensuring that unnecessary or inefficient capex is avoided.

The systems discussed in this Chapter underpin the management of the historic capex discussed in Chapter 3. The successful design and operation of these systems is critical to ensuring that only prudent expenditure is undertaken. These systems also underpin Powerlink's forecast of its capex requirements over the next regulatory period, which is reviewed in Chapter 4, not only by providing the criteria against which the expenditure requirement is measured but also by ensuring that the amount of capex to meet a particular requirement is estimated on a reasonable basis.

Powerlink's systems for the management of capex are therefore important from a regulatory perspective and the review of the extent that the design and operation of these systems is consistent with good industry practice at the time of a revenue reset will assist the AER to determine the efficiency of Powerlink's capital expenditures.

2.2 CATEGORISATION OF CAPITAL EXPENDITURE

Capex is expenditure to enhance or extend the level of service provided by the asset base, and includes expenditure on installing new assets and on replacing or refurbishing existing assets. On the other hand, opex is expenditure to ensure that the service levels that the asset base is capable of providing are actually delivered. Powerlink's forecast opex for the next regulatory period is discussed in Chapter 5.

While it is clear that expenditure on the procurement and installation of new assets should be classed as capex, the situation in respect of expenditure on the replacement or refurbishment of existing assets is less obvious. Powerlink applies generally accepted accounting standards for classifying such expenditure as capex or opex. If expenditure is to be classified as capex, it must materially extend the service life or enhance the service level provided by a separate asset recorded in its asset register.

However, Powerlink's asset register records asset types and quantities at a high level compared with some TNSPs. For example, some TNSPs quantify transmission line assets in terms of line length, meaning that a 50 km line would be effectively recorded as 50 separate assets, with each single asset being a line with a length of 1 km. However, Powerlink records transmission line assets as "built sections" of line. Under this approach, the same 50 km line could be recorded as a single "built section" provided all 50 km were originally built under a single contract. A second example is the classification of outdoor assets in substation switchyards. A high voltage switchgear bay may comprise structure and buswork, a circuit breaker, air break switches, and perhaps separate current and voltage transformers. Some TNSPs would individually record each of these equipment items as separate assets. However, Powerlink's practice is to record the switchgear bay as a single asset and not to itemise the equipment that makes up the bay as separate assets.

One consequence of this approach is that the Powerlink asset register will record a smaller number of higher value, more unique assets than a TNSP with a similar asset base that adopts a more detailed approach to asset categorisation. A more significant consequence is that Powerlink is more likely than some other TNSPs to classify expenditure as opex rather than capex.

To understand this better, consider the situation if Powerlink refurbishes 10 km of the 50 km transmission discussed above. This refurbishment might be classified as opex since the overall service potential of the "built section" of line would still be limited by the 40 km of line that had not been refurbished. Similarly, if Powerlink replaced the circuit breaker in the outdoor switchyard bay discussed above, the replacement cost would be treated as opex rather than capex. The impact of this practice is discussed and quantified in Section 5.5.8.

Powerlink uses a three tier categorisation system to classify capex as shown in Table 2.1. At the third tier, Powerlink identifies ten categories of capex as discussed below.

Table 2.1: Powerlink's Categorisation of Capital Expenditure

Tier 1	Tier 2	Tier 3
Network	Load driven	Augmentations
		Connections
		Easements
	Non-load driven	Replacements
		Security / compliance
		Other
Non network	Business – IT	Business – IT
	Support the business	Buildings
		Motor vehicles
		Assets, tools and other

Source: Powerlink Revenue Proposal, p56

Augmentation capex is driven by the need to increase the capability of the network to deliver active energy and typically includes the construction of new lines and substations and the reinforcement of the existing shared network. Where there is doubt as to whether or not capex should be classified as augmentation, Powerlink relies on the definition of "augmentation" in the National Electricity Rules (NER)[1]. Hence the replacement of a circuit breaker would be classified as a replacement rather than an augmentation, even if the main driver for the circuit breaker replacement was the need to increase the fault withstand capability of a part of the network.

Network connection capex relates to the installation of assets to connect customers to the shared network. These assets are generally used only by the customer or customers taking supply at the point of connection and would not be

1 The NER define "augmentation" as works to enlarge a network or to increase the capability of a network to transmit or distribute active energy.

required if a point of connection was disestablished. Connection assets are typically supply transformers and lower voltage substation assets.

Land and easements acquisitions are treated as separate capital projects and generally not included in the cost of the primary assets they support (e.g. lines and substations). Land and easements are often acquired well in advance of the asset being required, in which case by the time the primary asset is constructed the cost of the land or easement can properly be treated as a sunk cost. However this is not always the case, and sometimes the procurement of land and/or easements is undertaken immediately prior to asset construction.

The forecast requirement for load driven capex, including augmentations, connections and easement acquisition over the next regulatory period is discussed in Section 4.4.

Asset replacement expenditure relates to the replacement of existing assets that are no longer capable of providing the required service level. Most asset replacement is driven by poor asset condition, although asset replacement can also be triggered by factors such as inadequate fault withstand capability or by the fact that an existing asset does not comply with current safety, environmental or other legal requirements. Asset replacement comprises a significant component of Powerlink's forecast capex requirement for the next regulatory period and is discussed in Section 4.5.1.

Security and compliance capital projects relate to the installation of new assets or the refurbishment of existing assets as a result of changes to relevant safety, technical or environmental legislation. It also includes expenditure on enhancing the physical security of the existing infrastructure.

Other network related capital projects include the installation of network assets required to support the operability of the transmission system infrastructure and include communications system enhancements and the installation of additional switching capability.

Non-network capex includes assets required to support the management of the business, including information technology systems, buildings, tools and vehicles.

Overall we consider the methodology used to categorise capital expenditure to be logical and consistent with Powerlink's mission and business strategy. It does, however, impact the design and operation of Powerlink's business systems and gives rise to specific issues that are discussed in more detail later in this report. We note in particular the fact that the approach to asset categorisation results in a significant amount of expenditure, which should arguably be capitalised, being classified as opex.

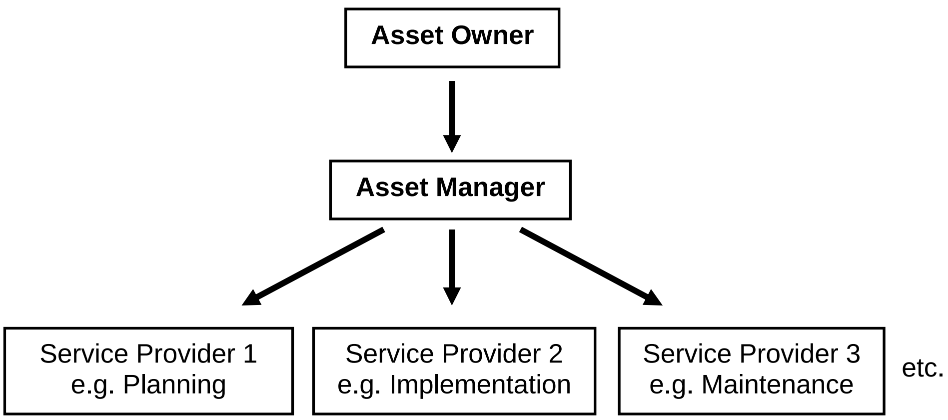
We also note that, as a result of its separate categorisation of easements, Powerlink does not consider easement or land costs to be part of the cost of a primary asset and does not include the cost of an easement in the economic evaluation of project alternatives where procurement of the easement is committed at the time the evaluation is undertaken. We also note that there is an element of augmentation in many asset replacement projects. Powerlink's approach to these issues can impact its analysis of network augmentation projects as discussed in Chapters 3 and 4.

2.3 BUSINESS MODEL

Powerlink's business model is based on an asset owner, asset manager and service provider hierarchy as shown in Figure 2-1. Under this model the asset owner undertakes the ownership functions such as corporate governance and financing. The asset manager is responsible for planning future network development, operating and maintaining the network, managing stakeholder relations and business risk. To meet its responsibilities the asset manager purchases goods and services from internal and external service providers who deliver a range of services including planning, operations, procurement, maintenance, project implementation, human resource management, field services, etc.

Powerlink's asset management group is also responsible for ensuring that Powerlink meets its obligations under the NER and other relevant instruments, including the Queensland electricity Act and Powerlink's jurisdictional Transmission Authority.

Figure 2-1: The Powerlink Business Model.



Internally the asset manager and service provider roles are accounted for on a functional rather than operational basis. Staff are required to account for their time through the use of timesheets and individual timesheet tasks are allocated either to asset manager or service provider functions. Staff can spend part of their time working on asset manager functions and part working on service provider functions and their costs are allocated accordingly through Powerlink's job costing system.

Powerlink undertakes both regulated and non-regulated business activities. Regulated activities include the management of the shared transmission network and connection assets connecting established grid users such as Energex, Ergon Energy and Queensland Rail. Non-regulated activities include the provision of connection assets for new users, and the provision of field related engineering and asset management activities to external parties.

In order to accurately allocate costs between its regulated and non-regulated activities, all assets and timesheet tasks are explicitly categorised as either regulated or non-regulated at their source. This process is discussed in more detail in Section 5.5.13.

2.4 PLANNING CRITERIA

2.4.1 Network Planning Criteria

Powerlink must plan its network to comply with the NER, the *Queensland Electricity Act 1994* and the Transmission Authority issued to Powerlink under Part 4 of this Act.

Under its Transmission Authority, Powerlink must plan and develop its network in accordance with good electricity industry practice so that the power transfer available through the power system will be sufficient to supply the forecast peak demand following the most critical single element network outage. While the Transmission Authority allows Powerlink to specifically agree otherwise with the affected distribution network owner or directly connected major customer, both Energex and Ergon Energy also plan their subtransmission networks to meet a similar N-1 planning criterion, consistent with the recommendations of the Somerville report[2]. Powerlink advises that this criterion is also reflected in its connection agreements with the two DNSPs. Hence Powerlink considers that meeting this reliability of supply obligation is non-discretionary, and it is the principle driver of investment in grid augmentation as load grows.

A credible contingency event is not defined in the Transmission Authority. However, credible contingency events that Powerlink takes into account when planning the network for the required level of reliability are the same as those defined in clause S5.1.2.1 of the NER and include disconnection of any single generating unit or transmission line/plant. Hence in planning its network Powerlink must ensure that, following a credible contingency event, the power system not only remains stable in accordance with the requirements of clause S5.1.8 of the NER but also that sufficient power transfer capacity remains so that there is no loss of supply to any connected customer.[3]

Powerlink, in accordance with good electricity industry practice, considers that four key technical limitations on its network can constrain the power transfer capability between locations in the network, and therefore potentially impact on its ability to meet forecast demand. These are:

- thermal limitations, where the consequence of overloading plant above its design levels could result in damage to the plant, reduction in its operating life or the breach of occupational safety and health standards such as the minimum statutory clearances under transmission lines;

- fault level limitations, which result in the need to replace plant with that of greater withstand capability or to configure the network so as to minimise redundancy and meshed arrangements;

- voltage control or voltage stability limitations, where there are specified requirements to maintain voltage levels and reactive power margins within acceptable bounds to maintain an acceptable quality of supply; and

- transient and dynamic (oscillatory) stability, where there is a need for the network to be designed and operated in a way that ensures that all generators and the system frequency remain within their stable and

[2] Queensland Department of Energy, July 2004, *Electricity Distribution and Service Delivery for the 21st Century,* Detailed report of the Independent Panel,

[3] Unless specifically agreed otherwise with the affected distribution network owner or directly connected major customer.

defined operating regions for system normal conditions or following a system disturbance.

In order to ensure compliance with the stability requirements of the NER and the reliability requirements of its Transmission Authority under the envelope of credible power system operating conditions, Powerlink has documented a Planning Criteria Policy[4], which forms the basis for assessing the requirement for and design of network augmentations. The main requirements of this policy are summarised below:

- Planning of the main transmission system, which extends to the provision of adequate transformation capacity at Powerlink's major substations that supply bulk power from the 275 kV backbone network to each of the zones[5], is based on the most recent 10% probability of exceedence (PoE) medium economic load growth forecasts as set out in the most recent Annual Planning Report (APR).

- As agreed with Energex and Ergon Energy, N-1 limitations within zones are based on 50% PoE medium economic load growth forecasts[6].

- In planning its network Powerlink plans to meet the required planning criteria with an outage of the single, most critical generator within the area or zone of study (often referred to as the N-G-1 criteria).

- The energy limited capacity of hydro power stations[7] is assumed for planning purposed to be:

    - Kareeya – 63 MW (from 88 MW nominal rating)

    - Barron Gorge – 15 MW (from 60 MW nominal rating)

    - Koombooloomba – 6 MW (from 7 MW nominal rating)

    - Wivenhoe – 150 MW (from 500 MW nominal rating).

- The reactive power capability of all generating units is assumed to conform to their registered performance standards.

- For system normal operation, the sustained flow on a transmission line must not exceed its continuous rating, which varies depending on the expected ambient (temperature and wind) conditions where the line is located.

- Under contingency operation, the maximum sustained flow on a transmission line must not exceed its contingency rating, which is based on shorter time spans and is higher than the continuous rating. Powerlink considers automated or manual (if it can take less than 10 minutes) network switching or selective load curtailment (load that is interruptible or dispatchable) is acceptable to reduce loading on a critical transmission line to within its contingency rating.

[4] Powerlink, *Planning Criteria Policy,* v1.0, 29/3/2006

[5] Powerlink models ten geographical zones including Far North, Ross, North, Central West, Gladstone, Wide Bay, South West, Moreton North, Moreton South and Gold Coast/Tweed.

[6] We note that Powerlink includes the 10% PoE in its planning process as do the distribution businesses, as discussed further in Section 4.4.1.

[7] The output of hydro power stations depends on water availability. Hence it cannot be assumed that the full capacity of his plant is available when required.

- Transformers should not be loaded in excess of their defined emergency cyclic ratings.
- Transient stability is assessed on the basis of rotor angle swings.
- Oscillatory stability is based on the halving time of the least damped electromechanical mode of oscillation being not more than 5 seconds.
- Voltage stability is maintained by ensuring appropriate reactive power (MVAr) margins at key buses are not less than 1% of the maximum fault level at the bus whilst de-scaling 275 kV connected capacitor banks by 5% to allow for the fact that at any one time not all equipment may be available.
- Before plant is replaced or augmented due to excessive fault levels, the prospective fault current that the circuit breaker must interrupt must exceed its rating (as opposed to assuming the full bus bar fault current applies).

The above network planning criteria is generally consistent with good electricity industry practice and the approach taken by the other TNSPs operating in the National Electricity Market (NEM) to the extent that they are appropriate in meeting the network performance requirements of Schedule 5.1 of the NER.

In particular, the 10% PoE medium growth demand forecasts selected by Powerlink for its main transmission planning analysis is generally consistent with good electricity industry practice. We note that Powerlink, like other TNSPs, will initially use this planning criterion to identify triggers for augmentation. The triggers and any need for augmentation will then be assessed in greater detail giving due consideration to sensitivities regarding matters such as different growth rates and temperature impacts. The use of a 10% PoE based demand forecast in this manner is prudent to ensure that extreme weather and its impacts on supply reliability are captured and analysed.

Nevertheless, the N-1 deterministic reliability criterion set out in Powerlink's Transmission Authority requires supply to be maintained to low capacity terminal stations that supply small communities such as the coastal towns between Townsville and Cairns, and is more onerous than the requirements of clause S5.1.2.2 (b) of the NER. This NER clause permits a reduction in the power transfer capacity of the network within a region[8], following the loss of a network element. Hence the Transmission Authority requires Powerlink to apply a lower threshold for grid augmentation in some areas than would necessarily be required by the NER.

2.4.2 Treatment of Generation

Powerlink plans its network on the basis that it assumes the largest critical generator in a single zone is unavailable before the deterministic N-1 planning criterion is applied. We agree that large generator outages require special consideration in the planning of power systems since, during a major overhaul; a generator may be unavailable for some weeks. While planned overhauls can be scheduled for times of low load on the network, the scenario in which a generator may become unavailable for some weeks following an unplanned internal or external fault, or fuel supply restriction is also realistic. Such events can, and do,

[8] Notwithstanding the fact that Powerlink disaggregates its network into four regions for internal management purposes (see Section 1.2), it remains a single region within the NEM.

happen and may mean that large generators will not be available at times of peak network load.

However the sudden and forced outage of a critical generator is less likely to occur at the time of high demand and coincident with a forced transmission line outage. Nevertheless the consequences of such a low probability event, if it did occur, are quite high. Unless the capability of the network to meet forecast demand under such conditions is planned, the consequence is likely to be load shedding. Typically the availability of generating plant is lower than that for transmission lines or transformers (95% compared with > 99%). Furthermore, the higher the number of generators in an area, and the lower their historical reliability, then more consideration needs to be given to the consequences of coincident generator and line/transformer outages.

Another relevant factor is that some generation is energy limited, which can lead to that generation being unavailable, or output constrained, even when it is not undergoing a scheduled or fault driven outage. For example the large Swanbank E generator in South East Queensland has a restricted gas supply, which currently restricts its capacity factor to about 50%.

The assumptions adopted by NEMMCO as part of its market simulation modelling for its Annual National Transmission Statement (ANTS) 2005 planning process[9] implied that Queensland base load and intermediate (hydro) generators had historical forced outage rates that were higher than other regions of the NEM and that its peaking plants had much lower forced outage rates than similar type units elsewhere.

Probabilistic based approaches to assessing the consequences of coincident generation and transmission outages are adopted by NEMMCO and at least one other jurisdictional planning body in the NEM. Such approaches contrast with Powerlink's N-G-1 deterministic planning criterion, which assumes that a generator will fail at the time of the transmission outage and which could therefore potentially result in more conservative planning decisions. However, to some extent, the higher generation forced outage rates in Queensland support Powerlink's decision to adopt an N-G-1 planning criterion.

There may be opportunities on a project by project basis where Powerlink could, after consultation with its customers, consider the implementation of a post contingency automatic network switching or load shedding scheme if the most critical generator within a region actually did fail prior to the critical summer period. This approach would be particularly relevant for a thermal constraint that may be mitigated by some other means in the near future.

Having regard to the above considerations, Powerlink's approach to network planning is discussed below for each of the key planning regions in Queensland. The specific planning assumptions made by Powerlink for each region are identified and are assessed as to whether the augmentation thresholds that Powerlink applies within each part of the network are prudent and reasonable, or whether they result in unduly conservative planning outcomes.

2.4.2.1 Central Queensland to Northern Queensland Transfer (CQ-NQ)

Powerlink plans its transmission network to meet demand in North Queensland using a range of assumptions about the availability of local generating capacity, which is subject to considerable uncertainty due to the age, mix and type of plant in the area. In particular, sustained low rainfall can limit the potential for hydro

9 NEMMCO, August 2005, *2005 ANTS Data and Assumptions – Final Report*.

and coal fired plant[10] to operate at rated capacity, non-scheduled cogeneration does not typically coincide with summer peak demand conditions and the high cost of fuel for open cycle combustion turbines, together with limited on-site liquid fuel storage capacity; limits their operation to strategic peak lopping.

Referring to Powerlink's publicly available reports on the supply reliability for North and Far North Queensland, the rated summer capacity of local generation facilities is approximately 930 MW. However much of this is low capacity factor plant, and the available capacity at any particular time is very uncertain.

The single most critical generator in North Queensland is the 230 MW Townsville combustion turbine.

Prior to undertaking a systematic review of the transmission capability from Broadsound to Ross as discussed in its *Final Recommendation to Address Supply Requirements in North and Far North Queensland in 2007-10*[11], Powerlink engaged the services of consultant Energy Market Services to review its assumptions about the availability of generating capacity in North Queensland. The consultant concluded that the range in potential operable capacity from the North Queensland generators over the summer months is large and, as a result, it is difficult to assess the adequacy of the transmission network against the assumption of the outage of a single critical generator. Consequently, Energy Market Services recommended that Powerlink assess the adequacy of the transmission capability over a range of generation capacity "sub-scenarios".

To some extent, this application of the "sub-scenario" technique extends Powerlink's Planning Criteria Policy, for example by:

- reducing the output of Kareeya to below 63 MW in three sub-scenarios to account for dry-year energy constraints on this plant;

- by assuming Townsville output is limited to 200 MW in three sub-scenarios where other major plant is available to provide for potential inaccuracies in forecast electricity demand;

- by applying an additional 'capacity on forced outage' factor[12] to the net generation;

- by adjusting the demand in accordance with the length of continuous operation available from the various generating sources; and

- by introducing a 75 MW demand sensitivity factor as part of the public consultation process.[13]

Given the nature and technology of the generation in North Queensland we agree that it requires particular modelling attention. We are concerned, however, that under some of the sub-scenarios the cumulative affect of all assumptions is to reduce the net output of generators to as low as 530 MW (approximately 55% of the combined summer rating) for the purposes of Powerlink's transmission

[10] The capacity of coal fired plant may be limited in dry weather by cooling water limitations.

[11] Powerlink, 2005, *Final Recommendation to Address Forecast Reliability of Supply Requirements in 2007-10 – North and Far North Queensland*.

[12] This is related to an operating policy of reducing the output of the next most critical generator following a forced generator outage.

[13] This is an adjustment made to the forecast demand to allow for improved economic conditions, errors in forecasting and increased temperature sensitivity. It is noted that this was only used in the public consultation and not as part of Powerlink's determination of its forecast capex.

planning. While this reduced generation capacity coincides with loading levels less than the peak forecast, and accepting that Powerlink considers the cumulative risk across all six sub-scenarios, we consider that Powerlink is being conservative in this aspect and that a less conservative planning approach is likely to defer network augmentations.

2.4.2.2 Southwest Queensland to South East Queensland Transfer (SWQ-SEQ)

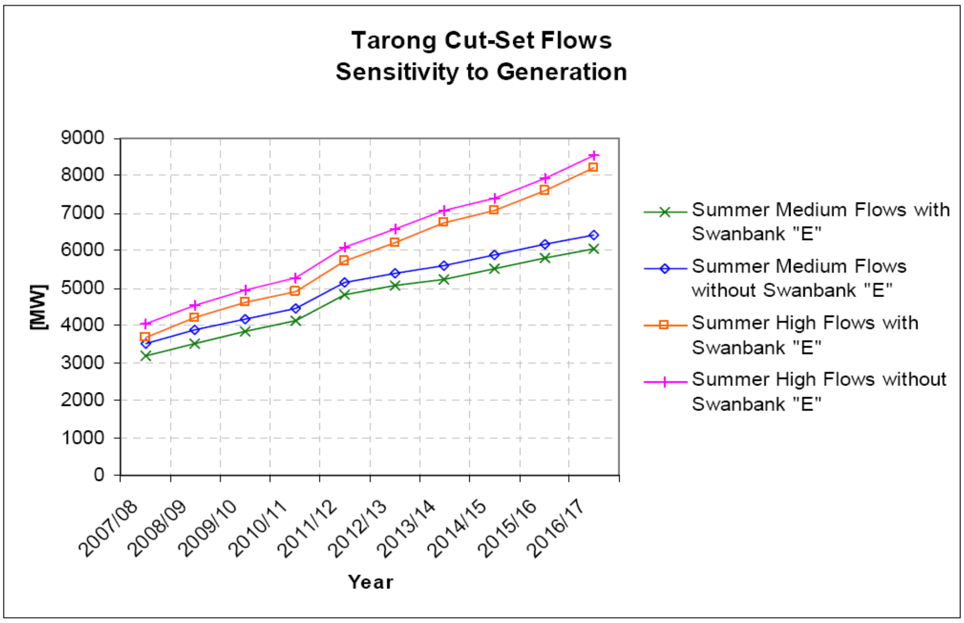
The maximum power transfer between South West and South East Queensland may be limited by transmission plant thermal capability, the occurrence of unstable voltage levels or transient instability following critical contingencies.

The adequacy of the transmission network to reliably meet the SEQ load has been assessed by assuming the outage of a single, critical generation unit in SEQ. The available generators in SEQ are Swanbank B (4x120 MW units), Swanbank E (355 MW) and Wivenhoe (2x 250 MW units). To assess the required SWQ-SEQ transmission capability Powerlink has assumed Swanbank E is forced out-of-service at the time of peak demand, to account for the fact that Swanbank E is energy limited as a consequence of its gas supply limitations.

Wivenhoe is a pumped storage hydro station with limited capacity in the upper pond, so that the pumping capacity of Wivenhoe is insufficient to allow it to fully cycle overnight pumping with day generation. The result is that full output cannot occur for the full 10-hour duration of peak demand during Queensland's summer days. The power output for Wivenhoe has therefore been assumed to be limited to 150 MW due to the energy limitations of its pumped storage arrangement. All other generating units in SEQ are assumed to be available and generating at maximum rated capacity for the purposes of transmission system planning.

To investigate the sensitivity of the timing of SWQ-SEQ augmentations to the Swanbank E generator outage assumption, Powerlink has plotted the required power transfer across the Tarong "grid section" with and without Swanbank E in-service. This comparison is shown in Figure 2-2 for both medium and high economic load growth.

Figure 2-2: Sensitivity to N-G-1 in South East Queensland.



Source: Powerlink

Based on the medium demand forecast, with Swanbank E in-service at maximum output, the same power flows occur across the Tarong "grid section" less than 2 years after a time when the trigger is reached with Swanbank E out-of-service. This would suggest that the assumption of Swanbank E out-of-service impacts augmentation works by advancing them by 1 to 2 years. Under high economic load growth, this would be less than 1 year.

We are satisfied with the N-G-1 planning standard adopted when planning across the SWQ-SEQ region boundary and agree that, given the low sensitivity of this assumption to the potential deferral of network augmentation, the potential consequences of a shortage of supply in the important SEQ load centre, and the potential capacity restrictions of Swanbank E due to its gas supply limitations, it is a prudent planning approach.

2.4.2.3 Central Queensland to Southern Queensland Transfer (CQ-SQ)

The CQ-SQ transmission capability must, at a minimum, meet the shortfall between SQ load and SQ generation (including maximum secure northern power flow from NSW). SQ includes both SEQ and SWQ. Available generation in SQ and QNI transfer capability are therefore both important.

Excluding new uncommitted generators identified by the ROAM Consulting scenarios discussed in Section 4.4.3, Table 2.2 summarises the current and committed generators in southern Queensland.

Table 2.2: Current and Committed Generators in Southern Queensland

Generator	Number of units	Generator Capacity per unit MW
Tarong (coal)	4	350
Tarong North (coal)	1	443
Swanbank B (coal)	4	120
Swanbank E (CCGT)	1	355
Oakey (combustion GT)	2	138
Roma (combustion GT)	2	27
Braemar (combustion GT)	3	150
Kogan Creek (coal)	1	724
Millmerran (coal)	2	430
Wivenhoe (pumped storage)	2	250

Source: Powerlink

To assess the required CQ-SQ transmission capability under the N-G-1 criteria, Powerlink assumes that Kogan Creek is forced out-of-service at the time of peak demand, coincident with Wivenhoe being constrained to 150 MW prior to the contingency due to the energy limitations of its pumped storage arrangement.

QNI is also dispatched to the maximum secure power transfer north. Under system intact conditions QNI is dispatched to 300 MW (800 MW for the QNI++ theme set).

Following the critical contingency, NEMMCO must be able to return the power system to a new secure state without pre-contingent load shedding. To assess this scenario, Powerlink assumes all available generation in SQ is dispatched to its maximum immediately following the contingency - this includes increasing the output of Wivenhoe to 500 MW (maximum capacity). Any southerly flow on DirectLink is reduced to zero and the northerly flow on QNI increased beyond the thermal limit between Tamworth and Armidale.

In order to increase the QNI flow above the thermal limit, with TransGrid's and NEMMCO's agreement a post-contingent load shedding scheme may be able to be implemented in Queensland to be activated in the event of a 330 kV line outage between Tamworth and Armidale. With this load shedding scheme in place the northerly transfer on QNI could be subsequently increased above the thermal limit of TransGrid's plant to the transient stability limit of around 580 MW.

The critical contingency for the transient limit is the trip of the largest generator in Queensland. For the N-G-1 condition considered (Kogan Creek out-of-service), a trip of Tarong North or Callide C unit is the next most critical contingency. To test the validity of this planning assumption, we have examined an alternative scenario of retaining Kogan Creek in-service, and assuming the next most critical southern Queensland generator is out-of-service (Tarong North). In this scenario, the QNI transient stability limit would be lower as it would now need to cater for the trip of the Kogan Creek generator. The resultant reduction in the QNI transient stability limit almost offsets the increase in generation capacity in southern Queensland (Kogan – Tarong North). Coupled with the knowledge that the CQ-SQ, N-1 secure, transient stability limit may well be lower, we conclude that the timing of the required N-1 secure transmission capability is not very sensitive to the Kogan Creek generator outage assumption made by Powerlink.

While noting that Kogan Creek is a newly developed state of the art single block 750 MW supercritical-steam coal-fired power station and that it should be quite reliable, we are satisfied with the N-G-1 planning standard adopted when planning across the CQ-SQ interconnector on the basis of the high number of critical generators in the region and the technical interactions with QNI constraints. We think it is a conservative but prudent planning approach. We also consider it is prudent for Powerlink to plan the transmission network in this region based on high import from QNI as this is likely to be the scenario that would be realised under high Queensland demand conditions and it is a reasonably likely market outcome.

2.4.2.4 General Conclusions on Treatment of Generation

Powerlink is required to plan its network to ensure forecast demand in Queensland is met for N-1 outages on the transmission network. Powerlink undertakes this planning responsibility giving due consideration to generation operating in the market environment by assuming that the most critical generator in its major load centres is unavailable (i.e. an N-G-1 approach). This appears to be a long standing practice in Queensland and is based on detailed experience and knowledge of the inter-connected power system. While we consider Powerlink's approach is conservative, we think that the sensitivity to this assumption on most investment decisions is relatively low and therefore consider the assumption prudent. However, we also consider Powerlink should continue to monitor the sensitivity of its assumptions in a transparent manner and continue to consider opportunities to implement low cost alternatives, such as control schemes, to minimise the consequences of scenarios that have coincident generation and transmission outages and therefore a reasonably low likelihood of occurring.

2.4.3 Plant Ratings

Manufacturers typically specify thermal equipment ratings based on continuous plant operation at the specified rating under prescribed installation and environmental conditions. However transmission network loads are rarely continuous, typically varying over a predictable daily cycle. Furthermore, installation and environmental conditions are invariably different from those assumed by manufacturers when calculating or testing plant capabilities. For these reasons, industry best practice is not to unquestionably rely on the plant ratings specified by manufacturers, but to assign ratings to individual plant items on the basis of their design capabilities, loading and installation conditions.

As a constituent member of the Plant Ratings Working Group, which includes all the transmission network owners in the NEM, Powerlink applies a standard methodology for calculating steady-state ratings for overhead transmission lines. Furthermore, for planning purposes (as opposed to operational purposes), it also applies static contingency ratings which attempt to simulate a rating that could reasonably be expected to prevail during short term contingency periods without undue risk. The development of such contingency ratings is based on large quantities of historical ambient temperature and wind speed data. The outcome of Powerlink's assessment is to adopt a 1 m/s wind speed for planning during contingency events. It has quantified the risk and considers it too risky to adopt contingency ratings at higher wind speeds.

Furthermore Powerlink takes localised climatic conditions into account in establishing its transmission line ratings for planning purposes. For the purposes of line ratings, Queensland has been divided into four climatic regions and each region is assigned a different temperature for both normal and contingency ratings and different wind speeds for normal ratings. These temperatures and wind speeds are based on historical weather observations.

We accept this planning position but consider that for operational purposes Powerlink might consider installing real time wind and temperature monitoring devices at selected locations, as have some other TNSPs in the NEM. This could potentially lead to the economic deferral of some projects which are driven by thermal constraints. We understand that Powerlink has considered such options at both a system wide level and on a project by project basis but consider that Powerlink should explicitly evidence its considerations further when assessing network alternatives for addressing constraints. We would expect that there are some opportunities for Powerlink to implement such arrangements, especially for some of its shorter, less risky, transmission lines in the South East Queensland area.

2.5 POLICIES AND PROCEDURES FOR GRID DEVELOPMENT

2.5.1 General

To ensure that the most prudent choice of grid development project is implemented for a given constraint, Powerlink uses a documented policy-driven process triggered by the initial identification of a "need". The identification of a need occurs either through a customer request or when a systematic transmission capability assessment determines that the demand on a part of the network is forecast to increase to the extent that the network will not be capable of providing the required level of power transfer without breaching the planning criteria discussed in Section 2.4.

Once the need is identified, Powerlink sets up a project team, coordinated by its Regulation Strategies and Development Group. The following groups are also included in the decision, but the main project sponsor depends on the nature of the project:

- Grid Planning;

- Plant Strategies; and
- Technology and Standards.

Grid Planning is typically the team that identifies the need for grid augmentation and customer connections to ensure Powerlink meets its regulatory obligations. Grid Planning also ensures that reliability of supply obligations are met and will develop the detailed project scope to take account of other expected network developments. The Plant Strategies Group ensures that any network development is consistent with Powerlink's asset management, plant and maintenance strategies and the Technology & Standards Group provides advice on technical design options and creates cost estimates for different project alternatives as required.

The Regulation Strategies and Development Group coordinates all inputs and ensures that regulatory requirements for project development are complied with. It also establishes arrangements for non-network solutions where appropriate, and provides input funding and project coordination.

2.5.2 Consultation Processes

In accordance with clause 5.6.6(b) of the NER, Powerlink consults with interested parties before it decides to construct a network augmentation with an estimated capitalised cost of over $10 million[14]. The consultation process includes the preparation of an application notice, which must include the following information:

- details of the proposed new large transmission asset;
- reasons why the new asset is needed (the need);
- all reasonable alternatives, including potential non-network solutions;
- relevant technical details;
- analysis of the ranking of the alternatives;
- a augmentation technical report prepared by the Inter-Regional Planning Committee (if and only if the asset is likely to have a material inter-network impact; and the applicant has not received the consent to proceed from all TNSPs whose transmission networks would be materially affected by the proposed new asset).
- details of how the application meets the regulatory test.

The consultation process allows interested parties to respond to the notice and Powerlink must respond to any submissions received.

On completion of the consultation process, Powerlink prepares a final report which is circulated to interested parties setting out the details of any submissions received from interested parties and its response to each such submission.

This consultation process is not required for augmentations with an estimated capitalised cost of below $10 million. However, before the construction of new small transmission network assets (with a value of between $1 million and $10

[14] This is the current threshold for a "new large transmission network asset" as defined in the NER.

million) Powerlink must publish an "intention to construct" notice in its APR and consult with interested parties on any submissions received in accordance with clause 5.6.6A of the NER. If such a project is not included in the APR or has changed significantly from what was published in the APR, then Powerlink is required to issue a separate report to interested parties – as specified in section 5.6.6A(c) of the NER.

2.5.3 The Regulatory Test

The regulatory test is an economic cost benefit test used by transmission and distribution businesses in the NEM to assess the efficiency of investment in network augmentations. It consists of two limbs:

- the reliability limb; and
- the market benefit limb.

2.5.3.1 Reliability Limb

The reliability limb of the regulatory test is used for evaluating reliability driven augmentations, which in the case of Powerlink, are driven by the service obligations imposed by the NER, the Electricity Act, its Transmission Authority and its connection agreements. The Transmission Authority requires Powerlink to:

"plan and develop its transmission grid in accordance with good electricity industry practice such that power quality and reliability standards in the NER are met for intact and outage conditions, and 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, unless otherwise varied by agreement."

Grid augmentations evaluated under the reliability limb must minimise the net present value (NPV) of the cost of meeting the required reliability standard, compared with a number of alternative options in a majority of reasonable scenarios. This approach to project assessments is commonly referred to as 'least cost planning'.

In conducting its regulatory test evaluations, Powerlink calculates the NPV of the various project alternatives to assess which option is most cost effective over a long time period. Currently, Powerlink generally calculates the NPV over a period of 15 years, but this is not fixed and can be extended if appropriate. For example, if a large network augmentation was anticipated in year 16, a longer analysis period would be used. It ranks the different project alternatives on the basis of this NPV analysis to identify the most economically efficient project that meets the need.

Powerlink's approach is to calculate the NPV of the change in transmission use of system (TUOS) charges resulting from the different project alternatives rather than the NPV of the estimated capital cost of the project. The approach used calculates the NPV of a *regular* stream of annualised costs, rather than the NPV of a more *irregular* pattern of capital costs, as would be the case if an NPV analysis of estimated costs was undertaken. In Powerlink's view this is a preferred approach, particularly when it is necessary to compare the cost of network and non-network alternatives, such as contracted grid support, which have different impacts over time. Powerlink's TUOS charges are calculated to recover the annualised cost of owning and operating network assets as well as the cost of any contracted non-network alternatives to provide the required level of reliability.

We are satisfied that Powerlink's TUOS NPV method is an appropriate method for ranking different project alternatives and is particularly suited to the direct comparison of network and non-network options.

2.5.3.2 Market Benefits Limb

In the market benefits limb of the regulatory test, the proposed augmentation should maximise the NPV of the market benefits to all those who produce, distribute and consume electricity in the NEM. Similar to the reliability limb, this needs to be demonstrated by a measure that can produce a ranking of alternatives based on most credible scenarios.

Powerlink has not justified any of the capex projects under review using the market benefits limb of the regulatory test because the reliability criteria prescribed in Powerlink's jurisdictional Transmission Authority prescribes reliability criteria that are non-discretionary. However Powerlink advises that it had previously applied the market benefits limb to the Central Queensland – North Queensland grid section, resulting in the initial grid support contracts with local generators in North Queensland.

2.5.4 Selection of Project Options

The integrity of the regulatory test is dependent on the selection of the project alternatives that a subject to detailed economic evaluation.

Powerlink's initial project planning includes a technical assessment of a wide range of network alternatives. Alternatives that do not pass this technical assessment are dropped and not considered further. Following this step, a short list of alternatives is taken forward for detailed costing and formal economic evaluation. Powerlink uses its experience, system knowledge and engineering judgement in a brainstorming style to select the most feasible options for economic analysis. In particular, it considers that its long experience in a high load growth environment guides it in eliminating options that might be more appropriate in a low load growth environment.

For network augmentations with a value of over $10 million, Powerlink has introduced an additional step to the consultation and regulatory test requirements discussed in Sections 2.5.2 and 2.5.3 of this report. This involves releasing a request for information (RFI) to market participants and interested parties prior to preparing the formal application notice required by clause 5.6.6(b) of the NER. The RFI describes the network limitations in some detail and outlines the required characteristics for non-network solutions – e.g. size, location, operating characteristics, extent of commitment and other key contractual requirements.

Powerlink considers this approach has been very successful in identifying potential non-network solutions. In the consultation associated with reinforcement of supply to North and Far North Queensland, it received 15 submissions of which 9 contained potential non-network solutions. As part of its evaluation and assessment process, Powerlink issued all potential non-network solution providers with an information paper outlining the timeframe and criteria for assessment of their solutions. The evaluation of options resulted in contracts for provision of grid support from two non-network solution providers.

We consider the processes in place to identify cost effective non-network project options to address network capacity constraints to be robust and well considered. As noted in Section 5.6.1, Powerlink indicates it has more grid support contracts in place than any other region of the NEM. Nevertheless the viability of non-network options in addressing network constraint issues has been limited and network augmentations remain the most cost effective approach to addressing the majority of network constraint issues.

Hence it is important that the most cost effective technically acceptable network options are identified and included in the regulatory test analysis. The process for the development of a short list of projects for full technical and economic evaluation does not appear to be formally defined and there are no documented criteria for technical acceptability. We see some risk in Powerlink's current project selection process that, without formal criteria for technical acceptability, the most economically efficient network project could be eliminated prematurely and not economically evaluated. This process would be improved if criteria for technical acceptability were formally documented and if the project documentation was required to include a schedule of all the project alternatives examined and the reason for the rejection of alternatives that were not taken forward. This would also facilitate an independent scrutiny of the assessment process.

2.5.5 Demand Side Management

Queensland has the highest annual load factor in the NEM, and one of the highest in the world. This is partly due to the high levels of residential demand side management (DSM) already implemented, including ripple or time clock control of a range of loads such as hot water, pool filters, dryers and even some air conditioning. These initiatives have been in place for many years. Therefore Powerlink considers that residential DSM is already being used to defer network augmentations to some extent. We agree with this in principle but a detailed research study would be required to quantify the impacts of DSM on Powerlink's capital expenditure program.

The technical characteristics of the Queensland transmission network, in combination with the relatively flat daily demand profile, impact on the suitability of DSM to further defer transmission augmentation. Powerlink has approached Queensland retailers, acting as aggregators of DSM solutions, and they have been reluctant to offer any services for deferring network investment, preferring to keep such services for hedging against high pool prices. Powerlink also meets with customer groups to discuss whether they would be interested in offering new and additional DSM solutions. However, it has only been successful in entering into limited DSM arrangements as some of the proposed arrangements are not suitable for use in meeting the reliability criteria specified in Powerlink's Transmission Authority.

The Department of Energy, Energex, Ergon Energy and Powerlink are also collaborating in a study on the development and implementation of a joint network demand management (NDM) program in Queensland. The aim of this program is to address short and long term objectives for deferring network investment, achieving sustainable reductions in peak system demand, shaping load curves and optimising energy consumption. The program involves investigating successful world-wide NDM initiatives, determining their appropriateness for the Queensland electricity industry and making recommendations to the Queensland Government on optimal benefit network DSM programs for the State to address rapidly increasing peak demand on electricity networks. The program only commenced in March 2006 and Powerlink envisages that successful outcomes may take many years to materialise. They are expected to eventuate as additional non-network alternatives to future grid augmentations.

In reviewing Powerlink's planning, project approval and regulatory test applications, we are generally satisfied that the identification, consideration and treatment of non-network options is appropriate. While the high growth characteristics of the Queensland power system and its demand profiles do not strongly favour such options, we consider Powerlink has endeavoured to overcome the technical and commercial complexities with the intent of deferring network augmentation. However, to meet Powerlink's Transmission Authority requirements, any DSM would need to be provided on a voluntary basis. Agreement and payment under network support arrangements would be required to achieve any deferral of network augmentation. There may be opportunities on a project by project basis but none have come forward thus far. In general, we also concur with Powerlink in the belief that the current regulatory framework with an ex ante allowance for capital expenditure will naturally incentivise Powerlink to seek non-network solutions if they can be implemented at lower cost than the capital expenditure allowances.

2.5.6 Cost Estimating - Base Planning Objects

Powerlink has an in-house estimating group that is responsible for preparing the costs estimates used as the basis for the economic evaluation of different project alternatives as well as for the more detailed cost estimates included in its business cases. The cost estimating group, which is part of the Technology and Standards Group, was also responsible for preparing all project cost estimates used in the analysis that produced the capex forecast in Powerlink's Revenue Proposal.

Powerlink's base planning objects (BPOs) underpin the majority of cost estimates. These are effectively unit rates for switchyard bays, transformers, lengths of transmission line, etc. The process used by Powerlink to create BPOs involves the preparation of a detailed (bottom-up) estimate for the cost of each component such as steel, aluminium, copper, electrical equipment, clearing, foundations, labour, installation, etc.

While Powerlink has many BPOs representing each individual building block of a transmission network, a relatively small number of BPOs constitute the majority of project costs. In particular, lines, cables, transformers and switchyards represent about 75% of the cost of Powerlink's forward capex program.

In assessing the appropriateness of Powerlink's BPOs, we reviewed project quotations related to historical capex projects and compared Powerlink's BPOs with independently derived cost benchmarks.

Project Quotations

We compared the costs of historical projects with cost quotations provided to Powerlink by its service providers. From this review, we consider that Powerlink is able to accurately estimate the cost of lines, cables and transformers when using the BPOs. For instance, Table 2.3 shows the difference between Powerlink's base BPOs and the quoted cost for transmission lines, adjusted for factors such as short line length and terrain as described in the project notes. The table shows that Powerlink has generally been able to estimate the costs of lines with phosphorous conductors to +/- 15%, which is a reasonable accuracy for the purpose of cost estimation.

We also examined the methodology used by Powerlink to create and review BPOs and consider that it is robust and is carried out at an appropriately detailed level, based on comparing actual project expenditures with project estimates.

We also found no indication that Powerlink has inflated its BPOs significantly from those used in the current regulatory period.

We have established benchmark costs for each of the key BPOs. In establishing the benchmarks, we have used publicly available data and also data available to PB Associates that is not in the public domain.

Table 2.3: Difference between Powerlink's BPO Costs and Cost Quotations for 275 kV Double Circuit Twin Phosphorous Steel Tower Lines

Project	Description	Length km	Difference[1] %	Comment
Project CP.01094 Belmont-Murarrie Transmission Reinforcement	Line 1 - 275 kV DCST twin phosphorous	1.5	-28%	Large difference due to short line length
Project CP.01094 Belmont-Murarrie Transmission Reinforcement	Line 5 - 275 kV DCST twin phosphorous	9.3	-15%	
Project CP.01002 Gold Cost Reinforcement	275 kV DCST twin phosphorous non cyclonic	39	15%	
Project CP.00707 Cairns Reinforcement	275 kV DCST twin phosphorous	73	15%	

Source: Powerlink historic projects
Note 1: A negative difference indicates Powerlink's BPO is less than the Cost Quotation

Independent Benchmarks

Few benchmarked costs are available in the public domain against which Powerlink's costs can be compared, and these are often for similar but not the same voltage and capacity levels. We derived benchmarked costs from the following published documents. The costs take into account differences in voltage and capacity levels and have been adjusted for time and currency differences as indicated:

- NSW Treasury, May 2003 – *Valuation of Electricity Networks Assets, A Policy Guideline for NSW DNSPs*. Costs have been adjusted for inflation.

- NZ Commerce Commission, 2004, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses*. Costs have been adjusted for different voltage levels, inflation and currency differences.

Table 2.4 shows the percentage difference between the average of the benchmark costs used for this analysis and Powerlink's equivalent BPO cost. The table also shows, for comparison, the range of the benchmark costs that we used. All costs are as installed and include design, installation and commissioning.

Two transmission tower line BPOs were reviewed. A high proportion of the lines to be built in the 2007-12 period require the high capacity provided by the use of sulphur conductor. For 275 kV double circuit twin sulphur conductor steel tower lines, the cost of Powerlink's BPO is 1% more expensive than the benchmark. Powerlink's BPO for 275 kV double circuit twin phosphorous conductor steel tower lines is 9% cheaper than the benchmark.

Both sulphur and phosphorous conductors are all aluminium alloy conductors and therefore the relevant BPOs could be expected to vary with the price of aluminium. As discussed in Section 5.5.5 of this report, we consider that by the start of next regulatory period the current high prices for aluminium could well have dropped back closer to more historical levels and therefore the recent abnormally high prices should not be reflected in the BPO. Given that Powerlink's BPO do not appear to have been inflated over the historical benchmarks, we consider that the BPOs for transmission tower lines are reasonable.

Table 2.4: Comparison of Powerlink's BPO Costs with Average Benchmark Costs

Item	Benchmark[1]		Powerlink BPO[1]
	Max	Min	
275 kV DCST Twin-Sulphur 2400A line	12%	-13%	1%
275 kV DCST Twin-Phosphorous 1800A line	5%	-10%	-9%
275 kV DC Twin-1200mm^2 cable[2]	0%	0%	-2%
275kV AIS 1 ½ CB Feeder bay with 2 CB's	13%	-13%	-6%
275/132 kV transformer 375 MVA ODAF	6%	-6%	4%

Source: Powerlink, PB Associates
Note 1: The comparison is with the average of the benchmark costs used for this analysis
Note 2: Costs of underground cable omitted pending clarification with Powerlink.

Powerlink's underground cable costs for 275 kV double circuit twin 1200mm^2 cable in its forecast capex program varied between $8,500 per km and $10,150 per km depending on the terrain, access and soil conditions. The available benchmark costs also varied widely depending on the date of the cable purchase and the corresponding cost of copper at the time. In addition to the cost of installation, the cost of copper represents a major cost of cables (approximately 20-25%). As discussed in Section 5.5.5 of this report the cost of copper has risen sharply since mid 2005 but seems to have peaked in 2006. We consider that by the start of the next regulatory period, the current high prices for copper could well have dropped back closer to historical levels and the recent high prices should therefore not be reflected in the BPO. Rather than adjust the benchmarks for the uncertain costs of the cable and installation, we compared Powerlink's BPO with a recent project of similar attributes. Taking into account this comparison and our views on the future cost of cable, we conclude that the BPO is reasonable.

For 275 kV switchyard bays, we found a significant variation (26%) in the benchmarked costs. These costs are as installed and could be expected to reflect the long run average of variables such as terrain, access difficulties, remoteness etc. As Powerlink's BPO excludes such factors (specific adjustments have been made as required for each project), it could be expected to be less than the benchmark average. At 6% less than the average, this BPO appears reasonable.

For 275/132 kV 375 MVA transformers, we found that Powerlink's BPO was 4% more expensive than the average benchmark but within the range of benchmarked costs. This BPO appears reasonable.

Overall, we consider that the key BPOs used by Powerlink to estimate its forward works program are reasonable.

2.5.7 Approval of Capital Projects

The final step in the project development process is creation of a business case for construction of the preferred project alternative. The business case describes the need for the project and may evaluate a limited range of project alternatives, particularly where there is little difference in the NPVs calculated during the economic evaluation. It also discusses community issues, as well as the project's strategic fit, cost and economic viability. The business case will also recommend the preferred project alternative for formal approval by the Powerlink Board or by senior managers with the necessary delegated authority.

The scope of work included in the business case will generally be more tightly defined than the alternatives used in the economic evaluation. As a result the cost estimate in the business case for the recommended solution should be more accurate. No expenditure can occur on project implementation until formal approval has been given.

Since the project need is driven by Powerlink's legal obligations to maintain a specified reliability of supply, the focus of the business case is to establish that the project has been properly scoped and costed, and that the recommended project alternative is the one that will allow Powerlink to continue to meet its legal obligations at the most economically efficient cost.

An alternative approach to project evaluation is rate of return, or energy at risk type analysis. This can lead to significant reductions in capital expenditure with comparatively minor reductions in the overall level of service. While some utilities have adopted such an approach, governments now appear to be requiring a more deterministic approach to the planning of electricity networks. For example DNSPs in both New South Wales and Queensland are required to plan the development of their subtransmission networks on a deterministic basis. Powerlink is also prevented from adopting such an approach since most capital investment is driven by the deterministic reliability criteria set out in its Transmission Authority.

2.5.8 Procurement

As a Queensland government owned company, Powerlink is subject to the Queensland Government's State Purchasing Policy (www.qgm.qld.gov.au) and these requirements are incorporated in Powerlink's Procurement Policy Manual (PPM). The PPM requires that, when purchasing equipment, materials and services; Powerlink maximises effective competition in the relevant markets for the materials or services required. Other requirements of the PPM include procurement planning, dealing with competent suppliers and purchasing in accordance with good professional practice and ethical behaviour.

Only individual purchases under $25,000 may have only one quotation. All other purchases require either three written quotations, or advertising, or approved competitive sourcing strategies appropriate to the market. In exceptional circumstances, an exemption from compliance with the PPM may be approved. Approval for an exemption requires significantly higher levels of financial delegation.

Powerlink ensures compliance with the PPM in three ways:

1. Compliance with the policy is personally signed off by officers of the Procurement Business Unit for each major contract.

2. Powerlink's auditor (KPMG) undertakes a series of rolling independent audits, under the direction of the audit committee of the Powerlink Board. Compliance with the State Purchasing Policy and Powerlink's PPM is thus checked regularly and Powerlink has been found to be fully compliant.

3. The Queensland Audit Office of the Queensland Government conducts ongoing audits of Powerlink's compliance with government policy, and no issues have been found with compliance with the State Purchasing Policy. The findings and recommendations from all audits are reported to the Powerlink Board's audit committee and all action items are followed up through regular reporting.

As contracts are implemented, Powerlink captures additional procurement efficiencies by discussing with successful contractors optimisations such as whether equipment should be supplied by the contractor or by Powerlink. If contractors can supply equivalent equipment at lower prices, then Powerlink prefers the contractor to provide the equipment rather than supply it from its own period contracts. Powerlink also discusses with contractors the purchase of bulk materials such as steel and where it is sourced from. Powerlink also accepts advice from the contractors on work methods and work method efficiencies.

Currently the following applies to Powerlink activities for capital projects:

- 70% of Powerlink's substation design work is outsourced;
- 100% of Powerlink's civil construction is outsourced;
- 90% of Powerlink's electrical erection is outsourced;
- 100% of Powerlink's secondary system panel manufacture is outsourced;
- 99% of Powerlink's transmission line construction work is outsourced;
- 30% of Powerlink's transmission line design work is outsourced; and
- 100% of Powerlink's transmission line steel structure design is outsourced.

During the course of our review of Powerlink's high level project delivery procurement policies we noted that:

- Downer EDI has been awarded a contract for the construction of new transmission lines in Far North Queensland after an eight month tendering process;
- Tenix Alliance has been awarded a period agreement for five years to refurbish and upgrade substations in the Mackay region and some southern regions around the Gold Coast and Brisbane;
- Powerlink takes a lead role in the Australia Pacific Utilities Group to enhance buying power and procure from new sources in volume;
- Powerlink's contractors now source tower steel from China rather than India, Turkey or Australia following competitive tendering processes;

Given Powerlink's structured and systematic governance arrangement with respect to its procurement processes, and that independent audits have found Powerlink to be compliant with the Queensland Government's State Purchasing Policy, we consider Powerlink is achieving reasonable procurement efficiencies. In particular, Powerlink's use of one-off and period contracts seems to be appropriate, given the nature of the plant procured through each contracting mechanism. Large, specialised plant is procured through one-off contracts and more regular, smaller purchases are being made through period contracts.

2.6 CONCLUSION

We consider that the methodology used by Powerlink to categorise capital expenditure to be logical and consistent with Powerlink's mission and business strategy. However assets are identified at a relatively high level and, as a result, expenditure that other TNSPs would capitalise is treated as opex. Furthermore easements are identified separately from the primary assets they support, and easement costs are not included in the economic evaluation of different project alternatives if the easement purchase was undertaken before the economic evaluation was completed. Where easements are purchased immediately before the project commencement, we consider that this approach has the potential to distort the selection of the most efficient project, although we did not identify any instance where this was actually found to be the case.

In planning the development of its network Powerlink is required by the NER to ensure that the power system will remain stable following a single credible contingency. However, reductions in power transfer within a region, which may result in the loss of load to customers, are permitted under Section 5.1.2 of the NER. Notwithstanding this NER reliability provision, under the terms of its Transmission Authority and its connection agreements with DNSPs, Powerlink is required to provide a full power transfer capability to all loads following the most critical single network element outage. We have reviewed Powerlink's planning criteria and consider them to be generally reasonable, given its obligation to comply with the NER and the additional constraints imposed by its Transmission Authority. However when applied to the Central Queensland – North Queensland load transfer, the planning criteria appear conservative and we consider this is likely to advance the need for network augmentations.

The development of a short list of projects for economic evaluation does not appear to be a formally defined process and there are no documented criteria for technical acceptability. We see some risk that the most economically efficient project could be eliminated prematurely and not economically evaluated. This risk would be minimised if Powerlink had documented criteria for the technical acceptability of projects and if it documented all rejected alternatives and the reasons for their rejection.

In reviewing Powerlink's planning, project approval and regulatory test applications, we are generally satisfied that the identification, consideration and treatment of non-network options is appropriate. There may be opportunities on a project by project basis to defer project augmentations by using DSM for network support, but none have come forward thus far.

Powerlink's procedures for project development are generally robust and consistent with the consultation and regulatory test requirements of the NER. Powerlink also provides an opportunity for public involvement in the development of project alternatives to large network augmentations and this is over and above the consultation requirements of the NER. This has led to Powerlink using third party provided generation as an alternative to network augmentation to a greater degree than any other TNSP in the NEM.

Powerlink has an in-house estimating group, which is responsible for preparing cost estimates for use in project economic evaluations and which also prepared the cost estimates used in the analysis used to develop the capex forecast in Powerlink's Revenue Proposal. Project cost estimates are underpinned by BPOs which are essentially unit rates for different asset types. We benchmarked some of Powerlink's key BPOs against external data and consider that the BPOs used in developing Powerlink's capex forecast to be reasonable.

Following the evaluation of different project alternatives, a business case is prepared and this is the basis for formal project approval. The business case is required to establish that the project has been properly scoped and costed, that the required project evaluation procedures have been undertaken, and that all required project development procedures have been properly implemented. The objective is to find the most economically efficient project alternative to meet the defined need. NPV economic analysis is used, and this is appropriate given the deterministic planning criteria set out in Powerlink's Transmission Authority. We note that some TNSPs are using rate of return or energy at risk type analysis. This may result in reduced capital expenditure and only a relatively small reduction in supply reliability, but is currently not an option for Powerlink as a result of the deterministic reliability criteria in its Transmission Authority and connection agreements.

Given Powerlink's structured and systematic governance arrangement with respect to its procurement process, and that independent audits have found Powerlink to be compliant with the Queensland Government's State Purchasing Policy, we consider Powerlink is achieving reasonable procurement efficiencies.

3. HISTORIC CAPITAL EXPENDITURE

3.1 OBJECTIVE OF THIS REVIEW

In Powerlink's November 2001 revenue cap decision[15], which determined Powerlink's revenue cap for the current (2002-07) regulatory period, the Australian Competition and Consumer Commission (ACCC) rolled forward the jurisdictional value of Powerlink's RAB to 1 January 2002. However in determining the revenue cap for the next (2007-12) regulatory period, the AER's Statement of Regulatory Principles (SRP)[16] has a preference for the 2002 valuation to be locked-in and rolled forward. Powerlink has agreed to lock in and roll forward its RAB. Hence the asset base will not be revalued as part of the current revenue cap assessment and the opening RAB for the next regulatory period (opening RAB) will comprise the RAB as at 1 January 2002, rolled forward to 1 July 2007 by adjusting for asset additions and deletions. However, the SRP provides that the capex over the current regulatory period will be included in the opening RAB only if it is considered prudent after an ex-post prudency review.

Further, the AER has indicated a preference to recognise capex on an 'as incurred' basis rather than on an 'as commissioned' basis. This change is expected to apply to Powerlink from 1 July 2007 and will result in the opening RAB including a work in progress (WIP) component for the first time.

As part of our technical assessment of Powerlink's Revenue Proposal, we have been tasked with reviewing the prudency of Powerlink's capex over the current regulatory period, including both the capex on commissioned projects and capex that it proposes be included in the opening RAB as WIP.

3.2 CAPITAL EXPENDITURE IN CURRENT REGULATORY PERIOD

Powerlink's 2001 revenue cap decision included a provision for capitalisations of \$1,042.99 million[17] (\$ nominal) for transmission capital expenditures from 2001/02 to 2006/07. In its Revenue Proposal for the 2007-12 regulatory period, Powerlink estimates[18] that \$1,274.11 million (\$ nominal) in works will actually be capitalised during the current regulatory period. Comparing the actual expenditure and adjusting the original allowance for actual CPI (\$1,054.96 million[19]), Powerlink expects to expend \$219.2 million (21%) more than the provision. Powerlink also proposes that a further \$529.95 million (\$ real 2005/06) to be rolled into the opening RAB for the next regulatory period representing the 'as spent' capex component of WIP in the current regulatory period, making the total capitalisation \$1,804.06 million (\$ real 2005/06).

In its Revenue Proposal, Powerlink stated that a number of factors contributed to the increase in capex during the current regulatory period, including: (i) a

15 ACCC, 2001, *Decision: Queensland Transmission Network Revenue Cap 2002-2006/07*. Note: The total allowance on p 61 of the 2001 decision is \$1,040.53m where summating the totals in table 6.1 on p 79 is \$1,042.99m. AER advised that \$1,042.99m is the correct figure for capex allowance.

16 AER, 2005,*Compendium of Electricity Transmission Regulatory Guidelines,* pp 23

17 Ibid, p. 79

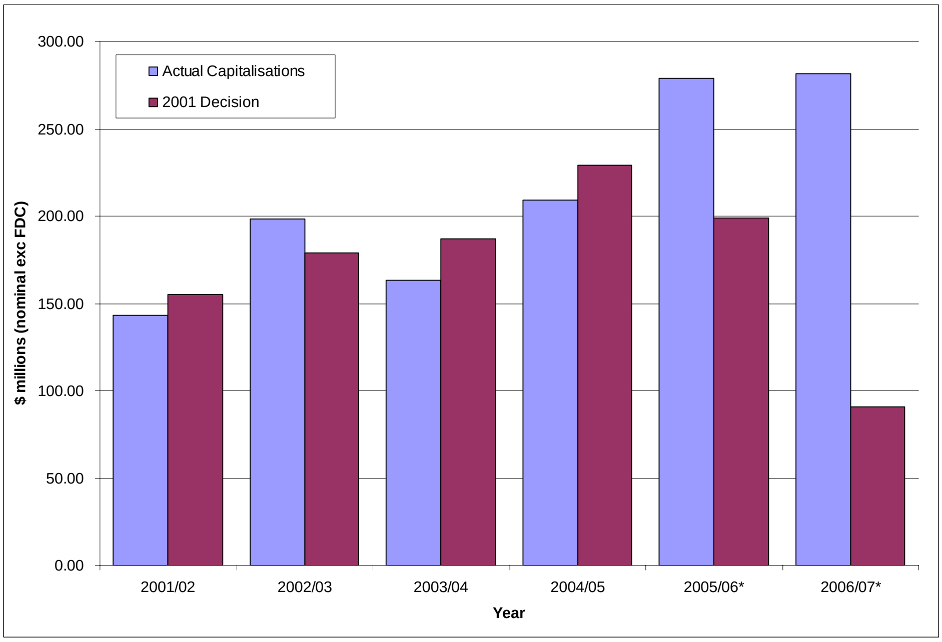
18 An estimate is required for the expenditure in 2005/06 and 2006/07 which will be capitalised between the time Powerlink's application was prepared and the end of the current regulatory period.

19 Queensland Transmission Revenue Proposal for the period 01 July 2007 – 30 June 2012; pp 23

demand growth that has exceeded expectations[20]; and (ii) higher than anticipated costs associated with labour and construction[21].

A profile of the actual capitalisations during the current regulatory period is shown in Figure 3-1 below. [22]

Figure 3-1: Forecast Allowance from 2001 Decision (escalated by CPI) and Actual Capitalisations during the Current Regulatory Period



Source: Powerlink and AER, 2001, *Queensland Transmission Network Revenue Cap 2002-2006/07*; Decision; p. 61. Figures include FDC.
Source: - CPI figures from the Australian Bureau of Statistics; June quarter 2006 report 6401.0; 2006/07 CPI estimated at 3%
Note: * Capitalisations for 2005/06 and 2006/07 are Powerlink's estimates

Figure 3-2 breaks down capitalisations over the current regulatory period by project category as defined by Powerlink. The chart includes Powerlink's forecast capitalisations for 2006/07.

Figure 3-3 shows the number of projects in each of the categories, including projects that are currently under construction, but due to be capitalised before the end of the regulatory period.

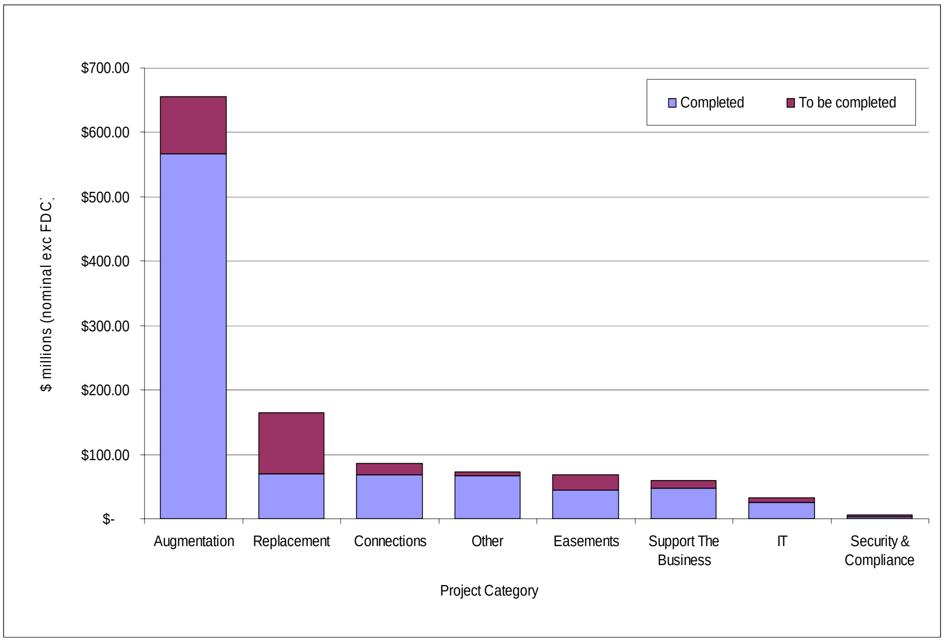
All projects that are due to commission before the end of the current regulatory period will be treated as historic projects for the purposes of this analysis. Projects that are started in the current regulatory period but not due to commission in the next regulatory period will be considered WIP projects.

20 Powerlink's temperature corrected peak demand peak demand in 2004/05 was about 7,400 MW. In Fig 2.1 of Powerlink's regulatory application for the current regulatory period the forecast medium growth peak demand for 2004/05 was about 6,500 MW.

21 Ibid, p. 23

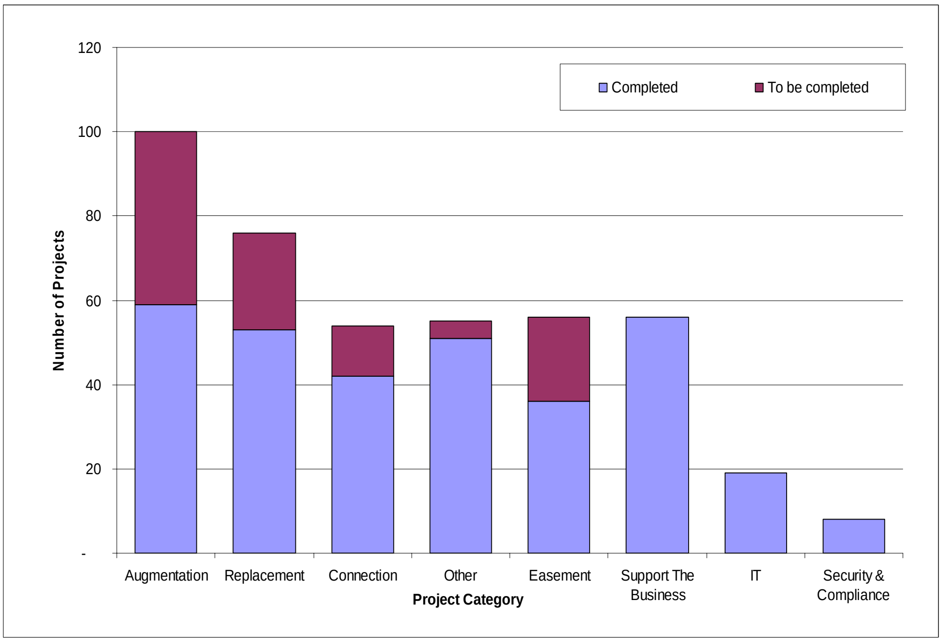
22 A capitalisation occurs when an investment is included in the RAB. During the current regulatory period, the cost of an asset is only capitalised after the asset has been commissioned.

Figure 3-2: Capitalisations by Powerlink in the Current Regulatory Period by Project Category including Estimate to the End of the Regulatory Period.



Source: Powerlink

Figure 3-3: Number of Projects Estimated to be Capitalised in Current Regulatory Period by Project Category



Source: Powerlink

3.3 PROJECT IMPLEMENTATION POLICIES AND PROCEDURES

Powerlink's primary driver for undertaking network related capital projects is to meet its obligations under Queensland legislation[23] and the NER[24]. These obligations, which are discussed in detail in Section 2.4, require that Powerlink augment its network on an ongoing basis to ensure that sufficient capacity is available to ensure that it continues to meet its obligations as the demand on the network increases.

3.3.1 Project Scoping

After the need for a new capital project has been identified, a range of project alternatives to address the need is developed. In the initial stages of project implementation a Powerlink project team is created with resources drawn from the Grid Planning; Plant Strategies; and Technology and Standards groups. The overall project is managed by the Regulation and Strategies and Development group.

This multi-disciplinary approach ensures that the project is scoped in a way that is consistent with Powerlink's long term network development strategy. It should also ensure that potential synergies with other network development and plant refurbishment requirements are captured and environmental and other impacts are taken into account.

This approach should ensure that projects put up for formal project approval have been properly scoped and costed. In common with other TNSPs, however, a major difficulty experienced by Powerlink in its transmission planning is that in order to maintain project schedules it is often necessary to seek project approval before public consultation is fully completed or easement routes finalised. Formal project approval is required before Powerlink is able to sign contracts for the procurement of long lead time items such as tower steel, conductor or power transformers. This timing issue can lead to project scope changes after a project has commenced.

3.3.2 Project Evaluation and Approval

Powerlink uses a three stage process for project evaluation and approval:

Project Identification

The first stage is the identification of a range of project alternatives. A list of possible alternatives is drawn up and assessed on the basis of their technical feasibility and fit with Powerlink's long term development strategies. Only those projects that meet the need within the required timeframe, are considered technically appropriate and show a good strategic fit proceed to the second stage.

Selection of Preferred Project

The second stage involves the selection of the preferred project from the technically appropriate alternatives. A high level cost estimate is developed for each technically appropriate alternative to identify those that are likely to be economic and efficient. For these cost estimates Powerlink uses the building

[23] Queensland Electricity Act 1994, Section 34 and Powerlink's Transmission Authority (No T0/98), Clause 6.2

[24] National Electricity Rules; Schedule 5 and specifically Clause S5.1.2.1

block approach discussed in Section 2.5.6. Those projects that appear to be more economically efficient are then subject to a detailed economic analysis, which is used to rank the different project alternatives.

The economic analysis is used to identify the project alternative with the lowest NPV, which is generally selected as the preferred option. Where two alternatives have a similar NPV, Powerlink may choose to put both forward for a full business case level analysis, although there are no documented requirements specifying when this must occur.

For network augmentations, the regulatory test and public consultation requirements occur during this second phase. While the economic analysis undertaken is similar for both augmentation and non-augmentation projects, Powerlink must comply with the NER requirements for the analysis of potential network augmentations. Non-augmentation projects are not subject to the external consultation requirements of Section 5.6.6 of the NER. Nevertheless, irrespective of the type of project, the output from this stage of the process is similar – the identification of one or sometimes two preferred project alternatives to be subject to a full business case analysis.

Business Case

For the business case the preferred project is scoped in detail and an accurate cost estimate is prepared. The business case, which is described in more detail in Section 2.5.7, is the basis for project approval and the allocation of funds to allow the project to proceed. Projects are generally approved at their estimated cost plus a 10% contingency allowance[25]. If the actual project costs do not exceed the 10% contingency then further board approval is not required.

Overall we found Powerlink's capital expenditure processes to be robust. Furthermore our detailed review of historic projects indicated that the processes were generally being followed.

However there appears to be a lack of rigour in the first stage of the project evaluation process where a long list of possible project alternatives is reduced on technical grounds to a smaller number of projects for economic evaluation. The initial short listing relies on experience rather than documented criteria to determine whether a project is technically acceptable. This could lead to subjectivity and inconsistency in the decision process and a consequent risk that the most economically efficient project alternative is prematurely rejected. Furthermore there is no requirement to document what project alternatives were rejected and the reason for rejection. This it makes it difficult to review why alternatives were rejected later in the project life cycle.

We also noted that easement acquisition and land purchase costs are sometimes not included when project alternatives are subject to economic evaluation. For example, we observed that in one project legal clearance costs were overlooked and not included in the evaluation. The reason is that, once a need is identified, Powerlink often proceeds to acquire an easement and, by the time the formal economic evaluation of project alternatives is undertaken, the easement costs are considered sunk and not included in the evaluation. This could impact the selected project alternative and potentially disadvantage non-network options.

Powerlink is in a difficult position, given the problems associated with easement acquisition and the time taken to resolve these problems. Nevertheless we think

[25] This is on the basis that the regulatory test includes the requirement to undertake sensitivity studies to ensure the robustness of decisions on project costs.

that acquisitions, land clearance costs and land purchases that are made after a firm need for a specific project is identified should be treated as project costs and included in the economic analysis, particularly where non-network alternatives are available. Ideally a full and detailed analysis of potential project alternatives should be undertaken at the time the decision is made to proceed with easement acquisition.

3.3.3 Management of Scope Changes and Budget Overruns after Approval

A major cause of project cost increases following project approval is public opposition to new line construction and the need to change the project route, or project delays while the issues raised are addressed. These factors accounted for $54 million of the total $90 million cost increase in the 40 commissioned projects that we reviewed. While Powerlink attempts to take all practical steps to mitigate these post-approval cost increases, they are largely outside their control. Cost increases of this magnitude explain Powerlink's preference for utilising all easements to their maximum capacity and underpin its reluctance to initially string only one circuit of a double circuit line, which would increase the number of times the affected landholders are disrupted.

For projects where the cost overrun is caused by scope changes or by an underestimate of the project cost, no action is taken until it is apparent that the cost overrun will exceed the approved project cost inclusive of the contingency. Projects that exceed this threshold are reassessed to ensure that the selected project alternative still remains the most efficient way of meeting the identified need. This reassessment takes into account any sunk costs, which may mean that the original alternative must proceed even if, with hindsight, it may not have been the most cost effective approach. This is reasonable and consistent with the AER's prudency guidelines, which do not seek to apply the benefit of hindsight.

If the cost overrun is due to a factor that is assumed would affect all of the proposed project alternatives, no reassessment of project alternatives is completed. An example would be additional costs due to a change in the work method to meet new safety requirements. This is based on the assumption that the cost increase would have an equal effect on all projects, and the timing would not be affected so the relative ranking of the different project alternatives would not change.

If the project budget thresholds are to be exceeded, and after any required project reassessment has been undertaken, approval must be sought for the additional funds in accordance with Powerlink's delegated authority. For large projects this is done through a board memorandum. We found during our project reviews that the board memorandum was limited in content and information on the drivers of the cost increase was light. However in these cases Powerlink was able to provide documentation supporting the board memorandum that showed to our satisfaction that, where appropriate, the appropriate economic analysis had been conducted.

We consider that the 10% cost overrun threshold is appropriate. However, for projects that are about to commence or are in the early stages of development, when it becomes apparent that the identified cost overruns will breach the threshold, Powerlink relies on its practical knowledge and experience in assessing the relative impact of the change on different project alternatives. We think Powerlink should apply a more robust and rigorous process that requires the economic impacts of the change on the different alternatives to be analysed in greater detail, in order to be sure that the most efficient project option is implemented. This is particularly important when grid support or non-network solutions are available options.

3.4 REVIEW OF SPECIFIC PROJECTS - OVERVIEW

3.4.1 General

There are 282 historic projects that have already been commissioned during this regulatory period and for which the actual capital costs at completion are known. A further 57 historic projects are expected to be commissioned before the end of the current regulatory period and which therefore include an estimated component in the project costs. The total cost of all 339 projects planned to be commissioned during the current regulatory period is expected to be $1,144.30 million, excluding finance during construction (FDC)[26].

However we found two errors in Powerlink's template spreadsheet that overestimated the historic project component of the proposed opening RAB by $1.42 million. These errors were in projects CP.01222 - Runcorn 110/33kV Spare Transformer and CP.01244 - Mackay Area Telecommunication Reinforcement. Correcting these errors reduces the proposed opening RAB to $1,142.87 million.

For this review we analysed 25 projects that have already been commissioned and another 15 projects that are currently in progress but which are expected to be commissioned before the start of the next regulatory period. The 40 projects reviewed represent 62% of the expected total capex on historic projects.

Powerlink has proposed that a further $480.41 million (excluding FDC) from 113 projects be included in the opening RAB for the next regulatory period as WIP. We reviewed 20 of these projects, which together account for 78% of Powerlink's proposed WIP component.

Of the 113 WIP projects, 5 were not included in the original information templates and 70 projects are either currently under construction or planned to commence in the next twelve months. The remaining 38 projects are included on the basis of a forecast probability weighted median commissioning date. These projects are discussed in Section 3.5.5.

The five projects not included in the information templates are all land or easement acquisition projects where the land will be procured and payments made prior to 30 June 2007, but where Powerlink does not expect the sale to be finalised until soon after the start of the next regulatory period. These projects were omitted from the templates because the expected expenditure in the next regulatory period is less than the forecast capex threshold of $10,000[27]. We accept this explanation and consider it reasonable for these projects to be categorised as WIP.

We selected a range of augmentation projects of different sizes for detailed review. The larger augmentation projects (greater than $10 million) are subject to the regulatory test and we wanted to confirm that the test had been properly applied. We also selected a number of smaller value projects since these projects in total comprise a significant proportion of Powerlink's capex. While it could be expected that high value projects would receive a rigorous treatment,

[26] The difference between this $1,144 million and the expected $1,274.11 million capitalisations for the regulatory period noted in Section 3.2 is FDC.

[27] In its approach to forecast capex, Powerlink has omitted as immaterial any project with an estimated total capex of less than $10,000.

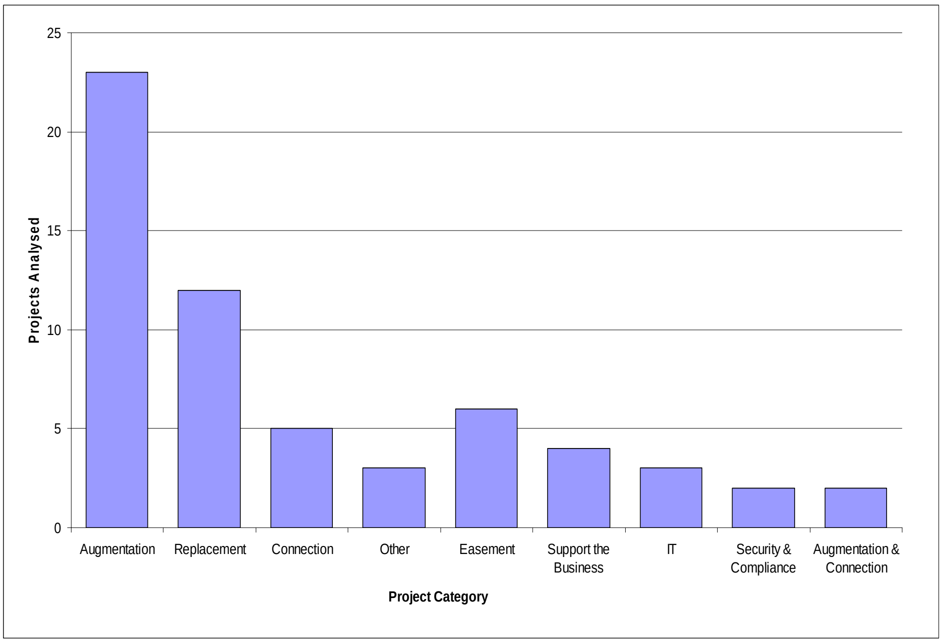
we wanted to develop a balanced view about the overall robustness of Powerlink's project evaluation and implementation processes.

Non-augmentation projects include a wide range of different project types and we therefore ensured that a selection of projects of each type was included in our review. The number of projects analysed in each category is shown in Figure 3-4.

The third part of the prudency test is an assessment of whether the actual project that was identified in the initial stages as being the most efficient choice was actually built. To ensure that this was the case, we selected a range of projects that were either over or under the original project budget.

The probability weighted projects which require some expenditure in the current regulatory period are considered as forecast capex for the purpose of this report. Some of these projects are included in the forecast capex projects that are reviewed in Chapter 4.

Figure 3-4: Number of Projects Analysed by Category



Source: PB Associates

3.4.2 Objective of the Review

We assessed the projects selected for detailed review against the three steps of the prudency test described below in Section 3.4.3. The assessment was the same irrespective of whether a project was classified as commissioned or WIP. In all cases, our assessment was made on the basis of information that should have been, available to Powerlink at the time the decision to proceed with the project was made. Consistent with the prudency test requirements, information that only became available subsequent to Powerlink making its decision to proceed was not taken into account.

The objective of the assessment was to determine whether or not a prudent TNSP would have made the same decision to proceed as Powerlink made and whether the actual expenditure on the project was reasonable.

In accordance with the principles of the SRP, if a commissioned project is deemed prudent and the expenditure efficient, the actual capex on the project is recommended for inclusion in the RAB. For WIP projects that are considered prudent:

- estimated expenditure up to 30 June 2007, is recommended for inclusion in the WIP component of the opening RAB on 1 July 2007; and
- estimated expenditure on the project after 1 July 2007 should be treated as forecast capex and rolled into the RAB at the end of the financial year in which it forecast to be incurred, irrespective of whether or not the project is scheduled for commissioning during that year.

If any project (historic or WIP) are not deemed prudent, or the expenditure excessive, only that portion of capex equivalent to what a prudent TNSP would have spent is recommended to be included in the opening RAB.

In the case of WIP projects where insufficient information was provided to satisfy us that it was probable that the expenditure estimated would actually be incurred before the end of the current regulatory period, we have recommended that the cost not be included in the opening RAB but be carried forward as forecast capex.

3.4.3 Prudency Test

The prudency test that we applied is taken directly from the SRP[28]. It is a three part test, designed to establish whether a project was required and whether the total expenditure on the project was prudent.

- First, we assessed whether there was a justifiable need for the investment. We examined whether Powerlink correctly assessed the need for investment against its statutory obligations. This assessment focused on the need for investment, without specifically focussing on what the most efficient investment to meet that need would be. An affirmation of the need for an investment did not imply acceptance of the specific project that was developed.
- Assuming an investment was required, we assessed whether Powerlink had proposed the most efficient investment to meet that need. In particular we considered whether Powerlink objectively and competently analysed the investment to a standard that was consistent with good industry practice. In applying this test we considered whether Powerlink had correctly applied its project evaluation and approval processes, described in Section 3.3.2, and whether the most economically efficient project was selected for implementation.
- We then assessed whether the project that was determined to be the most efficient was actually developed, and if not, whether the difference between the proposed and installed projects reflected decisions that were consistent with good industry practice. Where the constructed project was different, we examined in detail the factors that caused the

[28] ACCC, 2004, *Decision: Statement of Principles for the Regulation of Electricity Transmission Revenues – Background Paper*, p.132-133.

changes in the project design and/or delivery and assessed how Powerlink responded to those factors in comparison to what could be expected of a prudent operator.

A project had to pass all three assessments if the total project expenditure was recommended to be included in the RAB.

3.5 FINDINGS FROM THE REVIEW OF SPECIFIC PROJECTS

We reviewed 40 historic projects with an expected total cost at completion of $707.30 million and considered that $701.21 million of this cost was prudent. In reviewing these projects, we did not find any consistent or systematic problems with the approach that Powerlink adopted in evaluating or implementing commissioned or work in progress projects. Any problems identified were specific to a particular project under review.

We further reviewed 20 WIP projects that are not expected to commission before the end of the current regulatory period. There were 12 approved projects of which a WIP element of $267.98 million (excluding FDC) is proposed to be included in the opening RAB. We consider that $265.58 million (99%) of the proposed WIP expenditure on these projects was prudent and should be included in the opening RAB.

However we were concerned about the 8 remaining projects, with a total proposed WIP component of $111.01 million, which at the time of our review had not been submitted for project approval or were still subject to the regulatory test. We have not recommended that this amount be included in the opening RAB as discussed in Section 3.5.6.

A summary of the results of the individual project reviews is shown in Table 3-1, Table 3-2 and Table 3-3. A detailed discussion of each project reviewed is included in Appendix B to Appendix D, while the more general findings are discussed below.

3.5.1 Generic Circuit Design

In reviewing augmentation projects involving the construction of new transmission lines we noted that, generally, single circuit options did not form part of the economic evaluations we reviewed. We discussed this matter with Powerlink, which provided a statement about its approach to single circuit construction. This statement is included in this report as Appendix F.

In some cases it may have been possible to defer part of a project's cost by constructing only a single circuit on double circuit towers, leaving the second circuit to be strung later when it is required. Powerlink argues that for safety reasons it is unable to string a second circuit on a tower while the first circuit is live. We accept this. However it may be possible for Powerlink to program such work for times of the year when the load on the network is reduced and the first circuit can be taken out of service while the adjacent circuit is strung. In such situations it should generally be possible to return the isolated circuit to service, if required, within a recall time of 2 to 3 hours. In our review we saw little evidence of such options being seriously considered, possibly because the 2 to 3 hour outage under these circumstances would breach the requirements of its Transmission Authority and connection agreements.

Powerlink's preference for constructing double circuit lines to maximise the use of easements and avoid the need for future disruption to landholders is understandable, particularly in areas with significant demand growth. As detailed in Appendix F, page 7 of Powerlink's statement on Option Selection makes clear that it will consider the stringing of only one circuit initially if the second circuit is unlikely to be required within six years.

However in our review of specific projects, we did not identify any project where a double circuit line had been constructed that we did not consider was a prudent investment in the long term.

Powerlink has also suggested that one benefit of constructing double circuit lines is the reduction of electromagnetic radiation and the reduction of the overall reactance of the circuits, as a double circuit has a partially self cancelling effect. We accept this as a good design practice. However, in spite of significant and ongoing scientific research, it has still to be proven that electromagnetic radiation is potentially hazardous and we are not aware of any jurisdiction that does not permit the construction of single circuit lines because of concerns about electromagnetic radiation emissions.

Despite this, Australian TNSPs generally apply a policy of "prudent avoidance", so that if the potential risks of exposure to EMFs can be lowered by choosing one option over another option of similar cost, then that option should be preferred. We also note that, in Queensland, all new lines are constructed on dedicated easements and the construction of any building within this easement is controlled. These restrictions include not permitting the construction of any building occupied by the public, for example residential dwellings, thereby reducing any EMF radiation hazard.

While we consider the prudent avoidance approach to be reasonable, given the inconclusive findings of scientific research into the hazards of EMF radiation, we do not consider that it should preclude the construction of single circuit lines. Hence, for the purposes of this review, we have assumed that single circuit construction is acceptable where it is the most economically efficient project alternative.

In one project that we reviewed – the Bohle River to Townsville GT line – Powerlink applied the prudent avoidance principle to the area immediately outside of the easement. This increased the project cost by $2.4 million. Powerlink provided a Draft State Transmission Code proposed to be made under s.264 of the *Queensland Electricity Act 1994* that identified the application of 'prudent avoidance' in respect of electric and magnetic fields to the development of land nearby to easements. The draft regulation identifies a distance from the edge of the easement of 20 to 40 metres (depending on the transmission line voltage) to which the consideration of 'prudent avoidance' would be applied. In the Bohle River to Townsville GT line project, it was not clear how the buffer zone distances were established. Furthermore Powerlink was not able to evidence a consistency in its approach to assessing project options under the conditions set out in the draft code. Given that the draft code in not yet effective, Powerlink's is not legally required to apply it. Hence, we have recommend that the $2.4 million difference in cost between the most economically efficient project evaluated and the project actually implemented in the Bohle River to Townsville GT line not be included in the WIP component of the opening RAB.

3.5.2 Division of Projects

In our project reviews, we identified a situation where legal clearance and easement purchase costs were included in a separate project and were incurred less than one year prior to the commencement of the reinforcement project.[29] However, these costs were not included in the economic assessment of the reinforcement project. We recognise that strategic easements purchased well ahead of construction are a sunk cost and, as sunk costs are not avoidable, they should generally not be included in the cost of projects when undertaking an economic analysis in order to rank different project alternatives. However, in this instance the purchase and augmentation timescales were close together and the options evaluated included a grid support (non-network) alternative. In this case we think the easement related costs should have been included in the cost of the network option for evaluation purposes.

Nevertheless, in the above case, after re-analysing the NPV of the reinforcement with the additional easement included, we concluded that the project, as implemented, was prudent. We consider that, as a general rule, project alternatives subject to economic evaluation should be stand-alone and not dependent on projects that are not included in the evaluation. This should ensure that all costs required to fully complete the works are included in the economic evaluation. Where a project is split for administrative purposes this may mean that it is necessary to aggregate the separate individual projects for evaluation purposes. This applies particularly to transmission line and new substation projects where Powerlink's standard practice is to treat land purchase and easement acquisition as separate projects from the construction of the network assets.

3.5.3 Strategic Easements

When considering the second stage of the prudency test, we must *'…assess whether the TNSP proposed the most efficient investment to meet that need…'*.

For short term easement acquisitions this assessment is possible and reasonable supporting documentation was found to be generally available. This is notwithstanding the issues we have raised regarding Powerlink's treatment of easements in the economic evaluation of project alternatives, in situations where the easement was procured a short time before the economic evaluation was undertaken.

It is not possible, however, to verify that an efficient investment was made when applying this part of the prudency test to easements that are acquired well ahead of project construction commencing. This is because purchases of this nature are strategic and there is no evidence of the "efficiency" of the investment.

Nevertheless we believe that it can be good industry practice to purchase easements well ahead of construction, particularly if it is anticipated that changes in land use could have a significant impact on the future cost and availability of easements. To this end, we have divided easement acquisitions into short and long term and have applied the prudency test to the short term acquisitions only. We have made general comments where appropriate on longer term easement acquisition and, where we thought the investment was appropriate, we have recommended that the cost of the easement be included in the RAB.

[29] Project CP.00345 has two elements to the cost – (1) legal clearances and statutory purchase; (2) easement acquisition

Table 3-1: Commissioned Projects Reviewed

Report Reference	Project Number	Project Title	Powerlink's Initial Approved Cost (excl. contingency)	Powerlink's Current/Final Approved Cost (excl. contingency)	Cost at Completion	PB's Recommended Cost to be Included in RAB	Completion	Comments
			$m (escalated to completion)	$m (escalated to completion	$m (nominal)	$m (nominal)		
A.1	CP.00384	Lilyvale 275 kV Reinforcement	23.80	23.80	25.80	25.80	2004/05	
A.2	CP.00667	Molendinar 275 kV Establishment	23.70	23.70	23.50	23.50	2003/04	
A.3	CP.00668	Woree 132 kV SVC	16.30	16.30	14.80	14.80	2005/06	
A.4	CP.00707 CP.00742	Cairns Reinforcement	44.00	44.00	49.20	49.20	2002/03	
A.5	CP.00753	Stanwell-Broadsound 275 kV Line Reinforcement	33.30	39.00	37.40	37.40	2002/03	
A.6	CP.00762	Darling Downs Transmission Reinforcement	73.00	81.00	80.90	80.90	2004/05	
A.7	CP.00771	Belmont 275 kV Line Reinforcement	66.20	82.00	81.10	81.10	2003/04	
A.8	CP.00854	Loganlea 275 kV Establishment	19.00	26.00	23.50	23.50	2001/02	
A.9	CP.01002	Gold Coast Transmission Reinforcement	50.50	69.60	68.20[1]	68.20	2006/07	Completion due Oct 2006
A.10	CP.01081 CP.01121 CP.01038	Goodna, Algester and Summer Substation Establishments	35.30	35.60	39.30[1]	39.30	2006/07	Completion due Oct 2006
A.11	CP.01094	Belmont-Murarrie Transmission Line Reinforcement	42.60	42.60	47.70[1]	47.70	2006/07	Completion due Oct 2006
B.1	CP.00755	Murarrie 110 kV Establishment	23.20	23.20	16.10	16.10	2002/03	
B.2	CP.01030	Belmont-Murarrie Easement Acquisition	5.60	9.40	9.40[1]	9.40	2006/07	Completion due Oct 2006
B.3	CP.01055	Belmont-Murarrie Line Acquisition	1.10	1.10	1.06	1.06	2002/03	

Report Reference	Project Number	Project Title	Powerlink's Initial Approved Cost (excl. contingency)	Powerlink's Current/Final Approved Cost (excl. contingency)	Cost at Completion	PB's Recommended Cost to be Included in RAB	Completion	Comments
			$m (escalated to completion)	$m (escalated to completion	$m (nominal)	$m (nominal)		
B.4	CP.00791	Mackay Transformer Reinforcement	2.50	2.50	2.06	2.06	2002/03	
B.5	CP.01079	Bundamba 110 kV Substation Establishment	3.96	5.10	5.10	5.10	2004/05	
B.6	CP.01199	Queensland Rail Mindi Establishment	11.80	11.80	12.00[1]	12.00	2006/07	Completion Feb 2007
C.1	CP.00079	Substation Protection Upgrade Stage 2 – 220k Transfer to Opex	0.68	0.84	0.70	0.70	2003/04	
C.2	CP.00177	Gladstone South Substation Rebuild	13.60	13.60	13.60	13.60	2003/04	
C.3	CP.00836	Cairns 132 kV Substation Rebuild	11.00	11.00	12.80[1]	12.10	2006/07	Completion Oct 2006. Cost overrun not approved.
C.4	CP.01068	Middle Ridge 110kV Substation Rebuild & Secondary Systems Replacement	7.90	12.80	12.78	12.78	2005/06	
C.5	CP.01092	South Pine 275kV Substation Refurbishment	14.30	14.30	15.90[1]	15.73	2006/07	Completion Aug 2006. Cost overrun not approved.
C.6	CP.01142	Molendinar 110 kV Busbar Establishment	17.60	17.60	17.00[1]	17.00	2006/07	Completion Dec 2006
D.1	CP.00345	Stanwell-Broadsound Easement Legal Clearance	0.70	1.50	1.50	1.50	2001/02	
D.2	CP.00704	Springdale-Tarong Easement Acquisition	8.20	8.20	7.18[1]	7.18	2006/07	Completion Sept 06
D.3	CP.01034	Millmerran-Middle Ridge Easement Acquisition	4.85	8.90	8.28	8.28	2004/05	

Report Reference	Project Number	Project Title	Powerlink's Initial Approved Cost (excl. contingency)	Powerlink's Current/Final Approved Cost (excl. contingency)	Cost at Completion	PB's Recommended Cost to be Included in RAB	Completion	Comments
			$m (escalated to completion)	$m (escalated to completion	$m (nominal)	$m (nominal)		
D.4	CP.01226	Ebenezer Substation Site Acquisition	3.30	4.50	4.50[1]	4.50	2006/07	Completion Dec 06
E.1	CP.01222	Runcorn 110/33 kV Spare Transformer	0.36	0.36	0.42	0.42	2004/05	Contingency approval of 20% given.
E.2	CP.01244	Mackay Area Telecommunication Reinforcement	2.01	2.01	2.21	2.21	2006/07	Completion Nov 06
F.1	CP.96211	Upgrade Desktop Server Configuration	0.53	3.30	3.30	3.30	2003/04	
F.2	CP.96300	Desktop Replacement 02/03	1.50	1.50	1.75	1.75	2002/03	
F.3	CP.96502	Electronic Document and Records Management System	4.50	4.50	4.62[1]	4.62	2006/07	Completion Aug 2006
G.1	CP.00203	Collinsville-Strathmore-Claire Fibre Optic	3.20	3.20	2.50	2.50	2001/02	
G.2	CP.01298	Relocation of NOC Infrastructure	1.60	1.60	1.65[1]	1.65	2006/06	Completion Oct 2006
H.1	CP.01085	Transmission Line Emergency Restoration	1.13	1.40	1.40	1.40	2005/06	
H.2	CP.98200	Buildings	12.03	12.03	12.04[1]	12.04	N/A	Capitalisations as per table B.1
H.3	CP.98201	Virginia Office Complex	12.00	19.90	20.20[1]	15.00	2004/05	Additional cost not justified by Powerlink.
H.4	CP.99204	Tools and Equipment	4.75	4.75	4.75[1]	4.75	N/A	Capitalisations as Table
I.1	CP.00510	Alan Sherriff Substation & Garbutt Substation	5.50	11.00	11.40	11.40	2004/05	Initial project cost of $5.5m. Scope changed and cost increased to $11.1m

Report Reference	Project Number	Project Title	Powerlink's Initial Approved Cost (excl. contingency)	Powerlink's Current/Final Approved Cost (excl. contingency)	Cost at Completion	PB's Recommended Cost to be Included in RAB	Completion	Comments
			$m (escalated to completion)	$m (escalated to completion	$m (nominal)	$m (nominal)		
I.2	CP.00525	Edmonton 132 kV Establishment	9.20	9.20	9.68	9.68	2005/06	Initial cost of $0.7m for initial works at future site. Increased by $8.5 million to $9.2m following project planning.
		TOTAL	**616.30**	**704.69**	**707.30**	**701.21**		

Note: 1. Estimated cost.

Table 3-2: Work In Progress Projects Reviewed

Reference	Project Number	Project Title	Financial year the cost have been escalated to	Powerlink's Initial Estimated Cost (excl contingency)	Powerlink's Current Approved Cost (excl contingency)	Powerlink's Current Estimated Cost (excl contingency)	Powerlink's Cost Incurred up to the end of the Regulatory Period	PB's Recommended WIP Component of RAB	PB's Forecast Capex For the Next Regulatory Period	Comments
				$m (Escalated to completion)	$m (Escalated to completion)	$m (Escalated to completion)	$m (nominal)	$m (nominal)	$m (Escalated to completion)	
J.1	CP.01035	Ross-Townsville South Transmission Reinforcement	2007/08	17.30	17.30	16.50	11.23	11.23	5.14	Completion Oct 2007
J.3	CP.01186	NQ Transmission Reinforcement – Stage 1	2007/08	91.20	91.20	91.20	64.12	64.12	26.31	Completion Oct 2007
J.4	CP.01294	Strathmore 275 kV SVC	2007/08	38.00	38.00	38.00	21.02	21.02	16.50	Completion Oct 2007
J.5	CP.01124	Mackay Transmission Reinforcement	2007/08	46.70	46.70	47.00	32.93	32.93	13.65	Completion Oct 2007
J.6	CP.01138	South East Queensland Augmentation	2007/08	99.90	99.90	99.90	50.26	50.26	48.30	Completion Oct 2007
J.7	CP.01144	Townsville East Substation Establishment	2007/08	24.30	24.30	24.20	17.53	17.53	6.50	Completion Oct 2007
J.8	CP.01204	Lilyvale-Blackwater 132 kV Transmission Line	2007/08	30.30	30.30	26.50	16.13	16.13	10.12	Completion Oct 2007
J.9	CP.01266	Abermain 275 kV Substation Establishment	2008/09	22.60	21.20	21.00	8.40	8.40	12.23	Completion Oct 2008
K.1	CP.00752	SVC Secondary Systems Refurbishment	2007/08	28.90	28.90	12.39	1.34	1.34	10.26	Completion Jun 2008

Reference	Project Number	Project Title	Financial year the cost have been escalated to	Powerlink's Initial Estimated Cost (excl contingency)	Powerlink's Current Approved Cost (excl contingency)	Powerlink's Current Estimated Cost (excl contingency)	Powerlink's Cost Incurred up to the end of the Regulatory Period	PB's Recommended WIP Component of RAB	PB's Forecast Capex For the Next Regulatory Period	Comments
				$m (Escalated to completion)	$m (Escalated to completion)	$m (Escalated to completion)	$m (nominal)	$m (nominal)	$m (Escalated to completion)	
		Replace								$12.40m in this regulatory period, $10.26m in forecast capex and $1.34m as WIP.
K.2	CP.01022	Townsville South Secondary Systems Upgrade	2006/07	10.50	10.50	10.50	8.00	8.00	2.41	Completion Aug 2007
K.3	CP.01087	Bohle River-Townsville GT 132 kV Line	2006/07	18.00	18.00	18.10	16.15	13.75	1.88	Least cost option was not selected due to ESAA policy which is not explicit. Option 2 cost was $2.4 million higher than the most economical.
K.4	CP.01286	Tarong Substation Refurbishment	2007/08	20.80	20.80	23.80	20.87	20.87	2.84	Completion late 2007. Allowed contingency 20%
		TOTAL					**267.98**	**265.58**		

Table 3-3: Non-Approved Projects

Reference	Project Number	Project Title	Powerlink's Estimated Cost excl contingency $m (06/07)	Powerlink's Proposed WIP component $m (nominal)	Board Approval Sought by Powerlink	Estimated Completion Date	Comments
J.2	CP.01101	North Queensland Transmission Reinforcement – Stage 2*	110.05	22.68	During 2006	Oct 2008	
L.1	CP.01137/B	Ross-Yabulu Transmission Reinforcement*	35.66	7.63	Not confirmed	Sept 2008	Board approval has not occurred
L.2	CP.01198	Wide Bay Transmission Reinforcement	35.94	32.77	May 2006	October 2007	Board approval being made to the May meeting - no approval seen at time of writing
L.3	CP.01265	Bowen Transmission Reinforcement*	43.98	5.77	Not confirmed	2008	The release of the Application Notice in June / July 2006 was delayed
M.1	CP.01531	Bundamba 110/11 kV Transformer*	4.85	3.30	2006	2009	Board approval has not been sought yet. No confirmed date of approval
N.1	CP.01134	South Pine 110 kV Substation Refurbishment*	33.47	20.93	Not confirmed	Late 2008	
N.2	CP.01177	Belmont 110 kV Substation Refurbishment*	32.96	9.70	Not confirmed	2008/09	
O.1	CP.01313	Ross-Chalumbin OPGW Retrofit	8.31	8.23	May 2006	October 2007	Board approval delayed, no confirmed date of approval[1]
		TOTAL	**305.22**	**111.01**			

Notes: *Cost shown in Project Pack is as $m, 2005/06 or $m, at completion – Estimated cost shown in table as $m, 2006/07.

[1] Powerlink recently advised that this project has received formal board approval. PB Associates has not been able to reflect this information into this report.

Table 3-4: Probability weighted WIP Projects

Project Number	Description	Amount requested to be rolled into the RAB as WIP ($m)
CP.00364	Murarrie 275/110kV transformer augmentation	$0.1388
CP.00736	Greenbank 350MVAr SVC	$1.5087
CP.01189/B	South Pine to Sandgate 275kV Double Circuit operating at 100kV	$0.3610
CP.01195/A	Larapinta 275kV Substation Establishment	$0.6598
CP.01243	Bouldercombe to Pandoin 132kV	$0.1659
CP.01271/A	Woolooga to North Coast 275kV double circuit easement clearance and acquisition (TE component)	$0.1503
CP.01528/A	Molendinar 275/110kV transformer augmentation	$1.2141
CP.01533/B	275kV DCST Line into South West Brisbane	$0.3444
CP.01537	Greenbank to Mudgeeraba rebuild	$0.4200
CP.01540	Middle Ridge 330/275kV transformer augmentation	$0.1303
CP.01602	Abermain 110kV Feeder Bays for Wulkuraka	$0.0305
CP.01631/A	West Darra Transformer 110/11kV Transformer	$0.0451
CP.01659	Callide A 132kV Feeder Bay for Monto Mine	$0.0577
CP.01674/B	Brisbane South 110/11kV Substation Establishment Easement Acquisition (TE)	$0.0016
CP.01682/A	Clare 132kV Feeder Bay for Millchester No.2 Additional Land Acquisition (TE)	$0.0107
CP.01690/A	Logan to South Coast Line Rebuild Easement Acquisition (TE)	$0.2341
CP.01690/B	Logan to South Coast Line Rebuild Easement Clearance (compensation)	$0.0281
CP.01692/B	Bouldercombe - Pandoin 132kV DCST Easement Acquisition (compensation)	$0.0015
CP.01708/A	Kamerunga 3rd 50MVA 132/22kV Transformer Additional Land Acquisition (TE)	$0.0095
CP.01752	Woolooga Uprate Feeder Bays for Gympie Circuits	$0.0404
CP.01754	Richlands 2 x 110kV feeder bays	$0.0505
CP.01756	Runcorn 2 x 110kV feeder bays	$0.0485
CP.01771/B	275kV double circuit line to Larapinta	$0.7063

Project Number	Description	Amount requested to be rolled into the RAB as WIP ($m)
CP.01774	Larapinta 275kV connections	$0.1153
CP.01826/A	Easement Clearance into South West Brisbane (TE)	$0.0812
CP.01841	Millmerran Series Line Reactors	$0.0657
CP.01849/A	Callide A feeder bay Land Acquisition (TE)	$0.0146
CP.01850/A	Easement Clearance Larcom Creek to Bouldercombe 275kV DCST Line (TE)	$0.0033
CP.01854/A	Easement Acquisition & Clearance Gladstone to Wurdong 275kV DCST (TE)	$0.0056
CP.01854/B	Easement Acquisition & Clearance Gladstone to Wurdong 275kV DCST (compensation)	$0.0001
CP.01882	Moreton Central 120MVAr No 3	$0.0127
CP.01887	Moreton South 120MVAr No 2	$0.1390
CP.01888	Moreton South 120MVAr No 3	$0.0546
CP.01889	Moreton South 120MVAr No 4	$0.0187
CP.01896	Moreton South 120MVAr No 5	$0.0025
CP.01908	Moreton South East 120MVAr No 1	$0.1200
CP.01909	Moreton South East 120MVAr No 2	$0.0030
CP.01961/A	Sarina 132/66kV Transformer Land Acquisition (TE)	$0.0176
	TOTAL	**$7.01**

3.5.4 Cost Volatility

In its Revenue Proposal, Powerlink stated that a number of factors contributed to the increase in capex during the current regulatory period, including: (i) a demand growth that has exceeded expectations and (ii) higher than anticipated costs associated with labour and construction.

During the detailed review of individual projects we noted the reasons that Powerlink stated for cost overruns. We looked both at the impact of equipment and labour cost increases, which we would expect to cause project budgets to exceed the provisions made in the 2001 capex forecast. We also looked at the reasons for cost increases that occurred during the course of a project, where the final project cost exceeded the initially approved budget. These analyses are discussed in the sections below.

3.5.4.1 Cost Change from the 2001 Decision

Of the 60 projects that we detailed reviewed in detail, 34 projects were related to modifications to the transmission system. We looked at these 34 projects and categorised them according to the identified change. As a base we used the forecast cost from the 2001 Decision. Powerlink provided the additional comment on these 34 projects.

Of the 34 projects, 14 were not identified in the 2001 decision. Table 3-5 lists the reasons for the 14 projects proceeding.

Table 3-5: Reviewed Network Projects Not Included in the 2001 Decision

Reason for Inclusion	Number of Projects
Demand	4
Change to an existing project	4
Projects where a new need was identified after the 2001 Decision	
Obsolescence	1
Spares	1
IT	1
Security	1
Future Easement	1
Maintenance Equipment	1

Source: Powerlink past capex list

As can be seen from the table, of these 14 projects, four were needed due to demand increasing at a faster rate than predicted at the time of the 2001 Decision and a further four projects were variations to projects that were included in the 2001 Decision but that had changed in scope to the extent that a new project number had been assigned. The remaining six projects were identified as being required for the business to function but were not required to meet the demand.

Table 3-6 lists the reasons for any changes in project costs for the 20 projects that were included in original 2001 decision.

Figure 3-5: Reasons for Project Cost changes since the 2001 Decision

Reason for Changes	Number of Projects
On Target	8
Scope Change	4
Input Cost & Scope Changes	3
Legal and Easement Issues	2
Input Costs	2
Demand	1

Source: Powerlink capex list

The first item 'On target' shows that in the case of eight of the 20 projects, the costs came in within the forecast cost in the 2001 Decision.

The second main change was identified as changes in scope from what was originally envisaged. Cost increases for two projects were identified as being driven purely by higher input costs, but another three where due to changes in both scope and input costs. We were not able to identify what percentage of these projects costs was driven by either input or scope changes.

Only one project was identified as having the cost changed due to demand increasing at a higher rate that was originally estimated in the 2001 Decision.

This analysis indicates that while increases in demand and input costs had some effect in causing the actual capex in the current regulatory period to exceed the 2001 forecast, the impact of these factors was not overly significant. There is no doubt that Powerlink's demand, equipment and labour costs over the current five year regulatory period have been higher than assumed in 2001. The fact that these increases are not reflected to the same extent in actual project outcomes would indicate that they were largely absorbed by efficiency gains made by Powerlink. Had the assumptions in respect of demand and input costs that were used as the basis for the 2001 Decision turned out to be accurate, we think Powerlink's actual capex for the current regulatory period would have been significantly lower than the amount allowed in the Decision.

3.5.4.2 Changes from Initial Scope to Completion

The second stage of our review was an analysis of changes in costs from the initial cost estimate to completion of the project. We analysed all the projects that we received project packs for.

Of the 60 projects reviewed, 18 could not be evaluated against budget either because (i) they were projects such as fleet and buildings where an annual provision is made, (ii) they had still to be approved, or (iii) the project construction had not reached a stage where the cost at completion could be reliably estimated. We checked the remaining 42 projects for cost divergence from the initial quote. The actual or expected cost at completion of 26 of these projects was within 10% of the initially approved project cost. The remaining 16 projects were outside the budget contingency. Table 3-6 shows the cost variance grouped by category.

Table 3-6: Reasons for Project Cost Variances

Group	Description	No of Projects	
		Under Approved Cost	Over Approved Cost
On budget	Cost came in within the 10% threshold for business case projects and 15% threshold for regulatory test projects (taking into account year on year escalation of costs)	7	19
Scope change	The scope was changed from the original scope.	3	5
Local opposition	Local opposition and / or courts case delayed the project and increased the cost	-	7
Contract dispute	Dispute with contractor increased cost on resolution	-	1

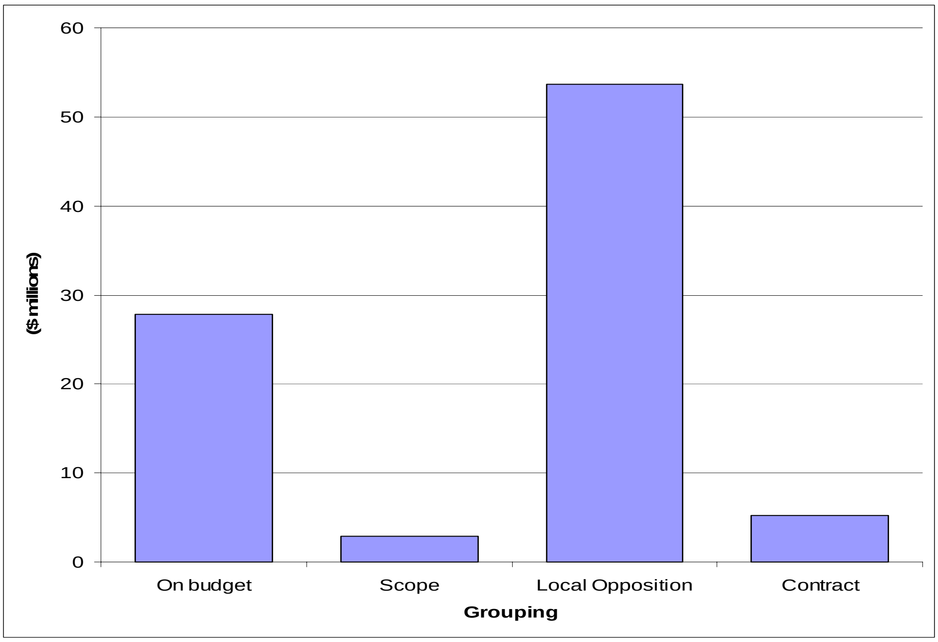
Source: Powerlink

The fact that there were significantly more projects that came in over the approved project cost than came in under is also reflected in Figure 3-6 which shows the overall net cost increase in each of the above groups. Figure 3-7 shows the number of projects in each group broken down by project category.

Additional costs of network augmentation projects were incurred through the cost of public enquiries and dealing with legal opposition to routes that Powerlink had planned as easements. These costs also arose when strategic easements were being purchased or progressed for near future augmentations.

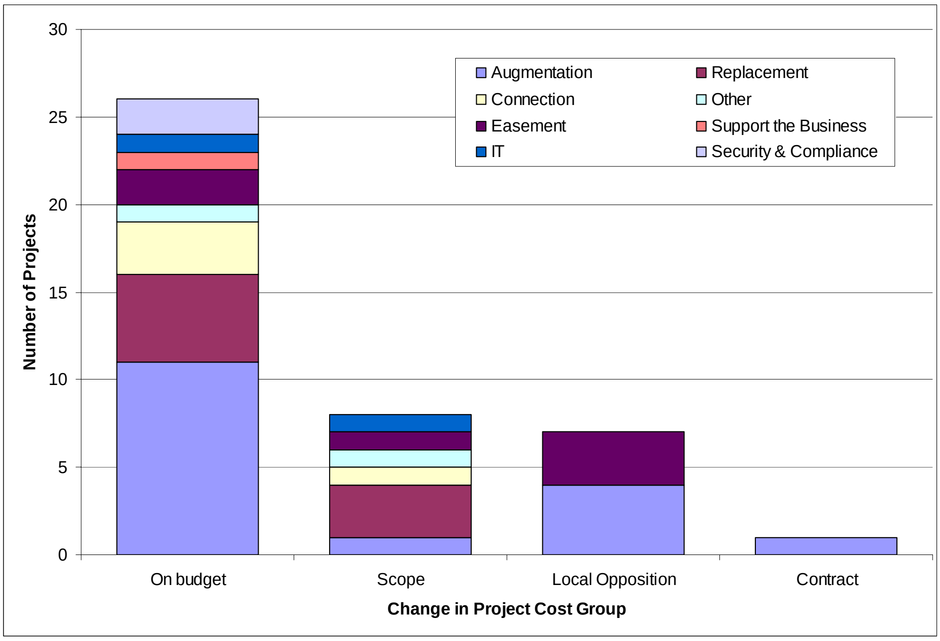
We found that in 23 of the projects that we analysed, scope changes occurred after the initial project approval had been obtained. Problems associated with acquiring land and easement routes were the main contributing factor in 14 of these projects. The reasons for scope changes in the remaining projects varied and are listed in Table 3-7.

Figure 3-6: Change in Cost of Projects by Category from the Initial Cost Estimate to Completion



Source: Table PB Associates; Data: Powerlink Project Packs

Figure 3-7: Project Cost Changes by Group and Category



Source: PB Associates

Table 3-7: Reasons for Project Scope Changes

Reason	No of Projects
Land and easement acquisitions	14
Additional work not included in original specification	23
Ensure security of supply during project implementation	1
Division of projects for administrative efficiency	3
Management of electromagnetic effects	1

Other than for land and easement acquisitions, the reasons shown in Table 3-7 all appear to be within Powerlink's control and in many cases could have been identified during project formulation. In particular, it could be that project synergies are not being identified and captured early in the project cycle. As a general rule scope changes during project implementation cost more than would be the case if the project had been correctly scoped at the time the contract was let.

We recognise that unforeseen work can occur in projects, but as can be seen from Figure 3-7 scope changes affect asset replacement projects in particular. As Powerlink has a significant amount of discretion in determining when an asset should be replaced, this indicates that the original scope assessment of asset replacement projects could potentially be improved. This analysis indicates that Powerlink could review its project development procedures to determine whether it is possible to reduce the need for late scope changes.

3.5.5 Probability Weighted WIP Projects

Of the 113 projects identified as WIP, 38 projects are included on a probability weighted basis. These projects are listed in Table 3-4. The value of these projects included in the proposed opening RAB for the next regulatory period is $7.01 million[30]. This provision

[30] Obtained from the Assets Under Construction spreadsheet supplied by Powerlink

has been derived from the capex forecast for the next regulatory period which has been determined using a probabilistic forecasting methodology. In this methodology, which is described in detail in Section 4.4.3, the annual capex for each theme scenario was derived by applying standard S-curves to work back from the required commissioning date for each project in the scenario. Given the standard S-curve duration was two years this approach indicated some expenditure prior to the beginning of the regulatory period. The $7.01 million therefore represents the weighted average value of the 2007-12 expenditure to be incurred towards the end of the current regulatory period.

Should capex included in the WIP component of the opening RAB not actually be incurred until the next regulatory period, the regulatory arrangements could allow Powerlink to both add the capex as WIP to its opening RAB and to add the actual capex in the 2007-12 period to its RAB on an ‘as built’ basis. Because of this potential for a double recovery of costs, we believe that the WIP component of the opening RAB for the next regulatory period should only include those projects that have a very high probability of actually incurring expenditure during the current regulatory period. Given that it is now less than twelve months before the start of the next regulatory period, we think any such projects should have been identified and included in Powerlink’s 2006/07 business plan. This is not the case for any of these projects.

For example for Project CP01537 – Greenbank to Mudgeeraba Rebuild, the commissioning date is stated as 2008 in the information template[31] but 2012/13 in the Grid Plan.[32] It has been allocated a 78% probability of occurrence. No expenditure has been explicitly identified to occur in the 2005/2006 or 2006/2007 periods. In the WIP/FDC spreadsheet provided by Powerlink, the earliest start date is listed as September 2006 and that $0.4 million will be spent on this project before 30 June 2007. This seems unlikely.

We believe that the probability of any capex being incurred during the 2006/07 financial year on any of the projects in this probability weighted group is very low and therefore recommend that the $7.01 million not be included in the WIP component of the opening RAB. Corresponding adjustments to the forward capex for these projects have not been made as Powerlink would need to adjust either the project completion dates or the expenditure profiles for these projects.

Potential double counting would be reduced if Powerlink and the AER agreed to update the estimate of the WIP expenditure close to end of the regulatory period so that the actual revenue cap reflected a more accurate estimate of the actual expenditure on WIP projects during the current regulatory period.

3.5.6 Timing of Work In Progress Projects

As noted in Section 3.4.1, the WIP component of the opening RAB, excluding FDC, is $480.41 million. Of this amount, $111.01 million (23%) represents eight projects for which business cases had not been finalised and the necessary approvals had not been given at the time of this review. These projects are shown in Table 3-3. Given the stage at which these projects are currently at, and the fact that less than twelve months remain until the start of the next regulatory period, we think it unlikely that Powerlink will be able to achieve all of the forecast WIP capex for these projects during the remainder of the current regulatory period.

We note for example that, while no project approval had been obtained at the time of this review[33], Powerlink is proposing to spend 98% of the estimated $8.4 million cost of the Ross-Chalumbin OPGW Retrofit project within the current regulatory period. It is

[31] Powerlink provided spreadsheets entitled “Powerlink Information Templates 2007 – 2012 proposal – corrected historic capex discriptions.xls”

[32] Grid Plan, version III, p H-14.

[33] Powerlink recently advised that this project has received formal board approval. PB Associates has not been able to reflect this information into this report.

proposed that all construction work on this project will essentially be complete at the end of this financial year (2006/07). We do not think that this work can be done live and consider it unlikely that a project of this nature can be completed by the end of this financial year, given that board approval for construction has not been obtained. Work requiring plant outages can be delayed where there are restrictions on the timing of the outages because of the need to ensure that Powerlink's continuing legal obligations in respect of network security and reliability are met.

Our concerns about potential double recovery of costs, where spending that is included in the WIP component of the opening RAB in not actually incurred until the next regulatory period, as discussed in Section 3.5.5, also apply to these projects. We therefore recommend that none of this $111.01 million be included in the WIP component of the opening RAB unless Powerlink can demonstrate with a much higher level of certainty that the projects have been approved and that the proposed capex can and will be incurred before the beginning of the next regulatory period. This expenditure should instead be included in the forecast capex for the next regulatory period. However corresponding adjustments to the forecast capex have not been made as Powerlink would need to adjust either the project completion dates or the expenditure profiles for these projects.

Alternatively it may be feasible for Powerlink and the AER to agree to update the estimate of the WIP component of the opening RAB close to end of this regulatory period so that it reflected a more accurate estimate of the actual expenditure on WIP projects during the current regulatory period.

3.5.7 Finance During Construction

Under the regulatory arrangements for the current regulatory period, capital works are included in the RAB after a project is commissioned. Hence the current revenue cap only provides for a return on the investment made in an asset after it has been capitalised. Given the high cost and long construction times of many transmission network projects, the financing cost over the construction period can be significant. Hence, in order to provide for the recovery of this cost, in its 2001 Decision the ACCC allowed an FDC factor to be added to Powerlink's actual capitalised expenditure.

FDC has two components. The first component, FDC1, is intended to compensate for the fact that Powerlink receives no return on any investment until the asset is commissioned. This factor varies with asset type, since the spend profile over the construction period will vary with the type of asset being constructed.

The second component, FDC2, is intended to compensate for the potential delay between the commissioning of a project and the time at which revenue is actually received. The need for this factor arises because the RAB is only updated at the end of a financial year, when the cost of all projects commissioned during the year is rolled in. Hence there is potentially a period (assumed to be half a year) between the commissioning of a project and the end of the financial year for which no revenue has been provided.

In its application Powerlink has determined the value of the opening RAB using the FDC factors that were used to derive the revenue allowance included in the 2001 decision[34]. However, we understand that these factors were calculated using the cost of capital parameters that did not reflect those determined by the ACCC and set out in Table 2.2 of the 2001 decision[35].

Under the regulatory arrangements that apply for this reset, the opening RAB for the next regulatory period is determined not by rolling forward the allowed revenue as determined in the 2001 decision, but by rolling forward Powerlink's *actual* capital expenditure over the

34 ACCC, 2001, *Decision: Queensland Transmission Network Revenue Cap 2002-2006/07*. P79

35 ACCC, 2001, *Decision: Queensland Transmission Network Revenue Cap 2002-2006/07*. P28.

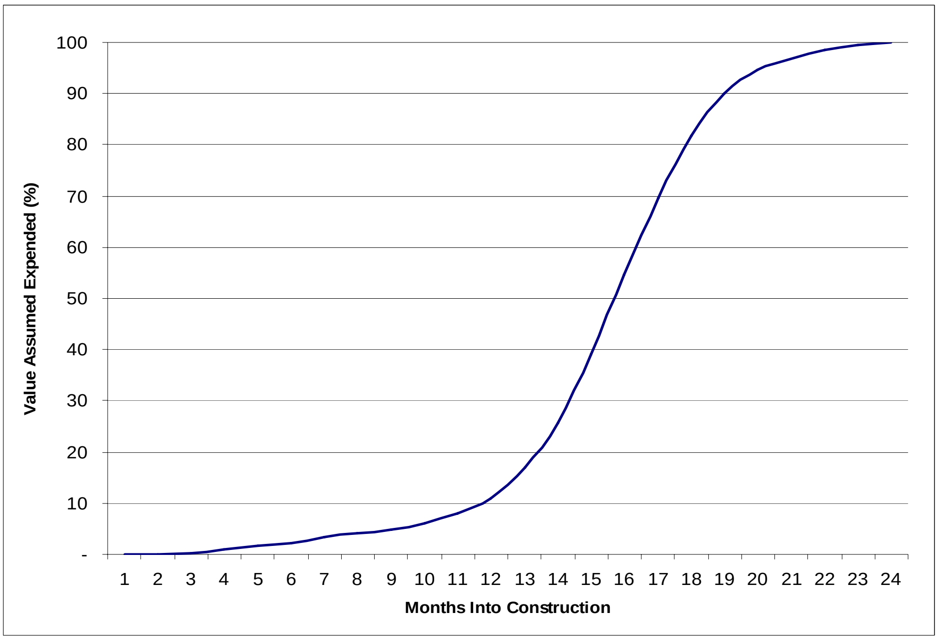
current regulatory period, provided the expenditure is shown to be prudent. In using this approach the AER has decoupled the determination of the opening RAB from the capital expenditure allowed in its 2001 decision.

We therefore consider it reasonable, and consistent with the principles developed by the AER for this revenue reset, that the opening RAB be determined on the basis of FDC components calculated using the cost of capital parameters determined by the ACCC as being applicable to the current regulatory period and set out in Table 2.2 of the 2001 decision. Furthermore, in determining the value of the opening RAB we consider the following approach to the application of FDC to be appropriate:

- For completed projects the recalculated FDC1 and FDC2 components of the opening RAB should be applied in full.
- For WIP projects a portion of the recalculated FDC1 factor should be applied depending on the state of completion of the project at the opening of the next regulatory period. The FDC2 component should not be applied since the expenditure will earn an immediate return from the time that it is included in the RAB.

Powerlink has estimated the portion of the FDC1 component to be applied to each individual WIP project in accordance with the asset type and the estimated months into construction at the end of the regulatory period, using standard normalised S-curve shown in Figure 3-8. This approach is reasonable.

Figure 3-8 Standard S-Curve Values to Calculate the Amount of FDC



Source: Powerlink

However in its application Powerlink has also applied an FDC2 component to the WIP component of the RAB. As noted above, we consider this to be inappropriate and recommend that it be removed.

Except where otherwise stated, all actual and estimated project costs in this report are exclusive of FDC.

3.6 CONCLUSION

The project evaluation and implementation procedures used by Powerlink for the evaluation and implementation of commissioned and WIP projects were consistent with good electricity industry practice and were generally well followed. However there appears to be a lack of rigour in the first stage of the project evaluation process where a long list of possible project alternatives is reduced on technical grounds to a smaller number of projects for economic evaluation. The initial short listing relies on experience rather than documented criteria to determine whether a project is technically acceptable. This could lead to subjectivity and inconsistency in the decision process and a consequent risk that the most economically efficient project alternative is prematurely rejected. Furthermore there is no requirement to document what project alternatives were rejected and the reason for rejection. This it makes it difficult to subsequently review the reasons for possible project alternatives being rejected.

Powerlink's actual capex in this regulatory period is estimated to be $1,144.30 million (excluding FDC), 22% higher than the forecast in the 2001 revenue cap decision. Powerlink is also proposing an additional $529.95 million (including FDC) as WIP to be rolled into the opening RAB ($480.41 million excluding FDC).

While increases in demand and input costs had some effect in causing the actual capex in the current regulatory period to exceed the 2001 forecast, the impact of these factors was not overly significant. There is no doubt that Powerlink's demand, equipment and labour costs over the current five year regulatory period have been higher than assumed in 2001. The fact that these increases are not reflected to the same extent in actual project outcomes would indicate that they were largely absorbed by efficiency gains made by Powerlink. Had the assumptions in respect of demand and input costs that were used as the basis for the 2001 Decision turned out to be accurate, we think Powerlink's actual capex for the current regulatory period would have been significantly lower than the amount allowed in the Decision.

Another factor driving the higher than forecast level of capex is an increase in costs from the initially approved estimate to project completion. We found that the main reasons for these increases were:-

- Project budget overruns due to the cost of resolving legal disputes (over the acquisition of easements)
- Extensions to project scopes after initial approval had been obtained.

We accept that the problems with easement acquisition are largely outside Powerlink's control and little can be done to avoid these. However, Powerlink has control over project scoping and we think it should look at its processes for project formulation to determine whether the scoping of projects during formulation could be improved and scope creep during implementation reduced. Nevertheless, we concluded that the increased expenditures were prudent in the projects that we reviewed.

We also noted that easement acquisition and land purchase costs are sometimes not included when project alternatives are subject to economic evaluation. We observed that in one project legal clearance costs were overlooked and not included in the evaluation. The reason is that, once a need is identified, Powerlink often proceeds to acquire an easement and, by the time the formal economic evaluation of project alternatives is undertaken, the easement costs are considered sunk and not included in the evaluation. This could impact the selected project alternative and potentially disadvantage non-network options. While Powerlink is in a difficult position, given the problems associated with easement acquisition and the time taken to resolve these problems, we think that acquisitions, land clearance costs and land purchases that are made after a firm need for a specific project is identified should be treated as project costs and included in the economic analysis, particularly where non-network alternatives are available.

When applying the prudency test to the acquisition of strategic easements well ahead of asset construction, it was not possible to fully apply the prudency test and, in particular, to confirm that the investment was efficient. This is due to the long term nature of the investment. Nevertheless we consider it good industry practice to consider and make long term acquisitions for easements, in situations where anticipated changes in land use may significantly increase the cost of future acquisition.

First we found two errors in Powerlink's template spreadsheet that overestimated the historic project component of the proposed opening RAB by $1.42 million. These errors were in projects CP.01222 - Runcorn 110/33kV Spare Transformer and CP.01244 - Mackay Area Telecommunication Reinforcement. Correcting these errors reduces the proposed opening RAB to $1,142.88 million (excluding FDC).

For this review we investigated in detail 60 projects to ensure that Powerlink was following its project evaluation and implementation processes and procedures and that the expenditure incurred was prudent.

We reviewed 40 historic projects that have commissioned or are due to commission before the end of the current regulatory period. The total expected capex on these projects is $707.30 million (excluding FDC) and we found that $701.21 million (excluding FDC) was prudent, a difference of $6.09 million. The two projects are discussed below:

- The cost associated with the Virginia Office Complex, where the contract amount was 75% more than the approved estimate. The cost overrun was identified early in the project cycle and we were not satisfied that the project could not have been reformulated to deliver a more economically efficient outcome. PB Associates recommends that $15 million of the requested $21.2 million is rolled into the opening asset base – a difference of $5.20 million.
- Two projects, CP.00836 and CP.01092 have exceeded their approved costs by $700,000 and $170,000 respectively. From the supplied information, the additional approval was not sought as is required by Powerlink's capex management procedures. We recommend that this additional cost of $0.87 million is not included into the RAB as the cost has not been properly approved. Furthermore Powerlink provided no supporting evidence that the cost overrun had been evaluated and found to be justified.

In reviewing these projects, we did not find any consistent or systematic errors in the approach that Powerlink adopted in evaluating or implementing commissioned or work in progress projects. Any problems identified were specific to a particular project under review.

We reviewed 20 projects that are under construction or are due to start construction before the end of this regulatory period and will commission in the next regulatory period. Of the 20 projects there are 12 projects of which a WIP element of $267.98 million (excluding FDC) is proposed to be included in the opening RAB. We consider that $265.58 million (99%) of the proposed WIP expenditure on these projects was prudent and should be included in the opening RAB.

- One project was considered to not meeting the second part of the prudency test – that the most efficient investment was implemented. The Bohle River to Townsville GT line project which incurred an additional expense of $2.40 million above the most economically efficient option on the basis of prudent avoidance of electromagnetic radiation. However, Powerlink was not legally obliged to incur this additional costs and basis on which the buffer zone distances were established was not clear.

- There were an additional 8 projects with a total WIP component of $111.01 million (excluding FDC) that at the time of our review had not been approved. Given the current status of these projects we consider it unlikely that Powerlink will be able to achieve the full proposed capex before the end of the current regulatory period. There is a potential for double recovery of costs if expenditure included in the opening RAB is not actually spent until the next regulatory period. We therefore recommend that these projects not be included in the WIP component of the opening RAB unless Powerlink can demonstrate with a much higher level of certainty that the projects have been approved and that the proposed capex can and will be incurred before the beginning of the next regulatory period. Instead this expenditure could be included in the forecast capex for the next regulatory period. However, as some of this expenditure may be incurred during the current regulatory period it may be possible for Powerlink and the AER to revisit this issue closer to the end of the regulatory period.

We identified a group of 38 projects that were in the probabilistic analysis of forecast capex which, on the basis of the commissioning dates used in that analysis and the assumed lead times, could require expenditure in the current regulatory period if they were to proceed. Powerlink has applied the probability weightings used in that analysis and has included this probability weighted expenditure ($7.01 million) in the work in progress component of the opening RAB. Powerlink, however, has not included any of these projects in the list of forecast capex projects on which expenditure will be incurred during this regulatory period and we therefore recommend that the probability weighted expenditure not be included in the opening RAB.

We consider the FDC factors applied to commissioned and WIP projects have been overstated and require adjustment. However further analysis is required to quantify any adjustment and this is outside the scope of our review.

3.7 RECOMMENDATION

The initial starting revenue request should be adjusted to remove the spreadsheet error of $1.42 million. Therefore the starting value will be $1,142.88 million.

We recommend that the following amounts (excluding FDC) should be rolled into the opening RAB:

- $701.21 million of the proposed $707.30 million relating to the historic projects reviewed;
- $265.58 million of the proposed $267.98 million relating to WIP projects reviewed;
- The cost of the remaining projects that were not reviewed, except for $7.01 million (excluding FDC) of probability weighted capex component of the WIP projects.

In summary, we recommend that the amounts shown in the following table be rolled into the opening RAB.

Table 3-8: Recommended capex to be rolled into opening RAB ($m, nominal)

Item	Amount[1]	
Revenue Request		
Powerlink Historic Proposal (excluding FDC)	**1,144.30**	
Powerlink Work In Progress Proposal (excluding FDC)	**480.41**	
Total proposal to be rolled into the RAB (excluding FDC)		**1,624.71**
Adjustments		
Spreadsheet error	1.42	
Reduction in historic capex (Table 3.1)	6.07	
Reduction in work in progress (Table 3.2)	2.40	
Reduction due to non-approved projects (Table 3.3)	111.01	
Probability weighted project cost (Table 3.4)	7.01	
Total reductions recommended		**127.91**
Recommended Capex to be rolled into the opening RAB		**1,496.80**

Note 1: Excluding FDC.

If these recommendations are accepted, an amount of $7.01 million for the probability weighted projects not allowed and $111.01 million for the projects not approved should be recalculated for revised commissioning dates and/or expenditure profiles and added to the forecast capex provision.

4. FORECAST CAPITAL EXPENDITURE

4.1 INTRODUCTION

The objective of our review was to assess the capex forecast contained in Powerlink's Revenue Proposal to determine:

- the appropriateness of the methods employed by Powerlink to forecast its required capex; and
- the adequacy, efficiency and appropriateness of the proposed capex to meet future reliability and service requirements.

Powerlink's capex allowance should cover all reasonable and efficient capital investment during the next regulatory period.

In contrast to an ex-post regime, an ex-ante capex regime places a greater emphasis on a rigorous review of forecast expenditure before it is actually undertaken. This is because, under the ex-ante regime, a TNSP has an incentive to overstate its forecast capex requirements in its Revenue Proposal since it is allowed to retain any difference between the allowed and forecast capex until the end of the regulatory period. As described in the SRP, this incentive scheme is symmetrical. If Powerlink spends less than the allowed capex, it can keep its excess revenues whereas, if it spends more, it must fund the excess expenditure itself. It is therefore in the interests of both Powerlink and its customers that the capex requirements over the next regulatory period are forecast as accurately as possible.

However, it should be noted that the rigour of the review must be tempered by the fact that the process is a forecast, and as such its accuracy decreases towards the end of the period. The information available on projects required towards the end of the period is more limited than with projects that are planned earlier in the period. Powerlink has advised that for many of its longer term augmentation projects, it has only carried out a high level review of options to provide an indication of which one would be likely to pass a detailed regulatory test assessment. A full regulatory test assessment would only be carried out when planning the implementation of a specific project.

In its Revenue Proposal, Powerlink has forecast its capex requirement on the basis of the policies and processes outlined in Chapter 2. Consistent with the approach outlined in the SRP, Powerlink's forecast capex has been developed through a probabilistic assessment of potential investment during the regulatory period. The output from this analysis is a probability weighted forecast capex requirement for each year of the regulatory period. Under the ex-ante regime, the allowed capex provision does not entail project specific approval and therefore Powerlink is not obliged to develop the specific projects included in the allowance.

In addition to its ex-ante forecast capex allowance, Powerlink has put forward ten projects which it considers are large and uncertain and has proposed that these projects be treated in accordance with the contingent projects provision of the SRP.

4.2 POWERLINK'S REVENUE PROPOSAL

The forecast capex set out in Powerlink's Revenue Proposal is $2.45 billion (on an as-incurred basis) for the next regulatory period as outlined in Table 4.1.

Table 4.1: Forecast Capex over the 2007-2012 Regulatory Period ($m, 06/07)

Type	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Network	527	521	433	446	418	**2,346**
Non-Network	19	22	23	20	20	**104**
Total	**546**	**543**	**456**	**466**	**437**	**2,449**

Source: Powerlink Revenue Proposal, p. 83

This compares to the actual capitalisation over the current 2001-07 regulatory period of $1.27 billion, as shown in Table 4.2.

Table 4.2: Capex over Current 2001-2007 Regulatory Period ($m, nominal)

Item	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	Total
Allowed Capex[1]	155.24	179.04	187.59	230.11	199.56	91.46	**1,042.99**
CPI adjusted	155.24	180.11	190.78	233.23	202.34	93.25	**1,054.96**
Actual Capex	128.37	178.05	145.62	187.30	252.04[2]	252.92[2]	**1,144.30**[2]
FDC	14.89	20.22	17.36	22.10	26.67[2]	28.57[2]	**129.81**[2]
Actual capitalisations	143.26	198.27	162.98	209.39	278.72[2]	281.49[2]	**1,274.11**[2]

Source: Powerlink Revenue Proposal, p. 25 and 26
Note 1: As provided in ACCC's Decision of November 2001.
Note 2: Forecast.

As a consequence of the change in regulatory approach from 'as commissioned' capitalisations to 'as incurred' expenditure from 1 July 2007, Powerlink is seeking to have an additional amount of $529.95 million rolled into its opening RAB for works expected to be in progress at 1 July 2007, in addition to capitalisations of $1,274.11.

Due to this change in approach it is difficult to directly compare Powerlink's forecast capex to its historic capex, but by adopting the 'as incurred approach' and assuming that the work in progress at the start of the current regulatory period that would have been expended in the previous period is around $300 million, then Powerlink's forecast capex for the next regulatory period ($2.4 billion) is approximately 1.6 times the amount that Powerlink is likely to spend over the current (2001-07) regulatory period ($1.5 billion). Powerlink considers the three key aspects underlying its increase in capital expenditure are continuing high demand growth, rising input costs and the ageing of its existing assets. Each of these factors will be discussed in further detail later in this report.

For the next regulatory period, Powerlink's capex allowance must cover all required and efficient investment. Due to the long lead times of transmission network projects, Powerlink's capex forecast includes capex for projects that could be commissioned as far out as 2016. The impacts of the as-incurred approach and project payments are discussed further in Section 4.8.

4.2.1 Network Capex

Expenditure on the network comprises approximately 96% of the total forecast capex for the next regulatory period. It covers investment associated with Powerlink's transmission lines, switchyards, transformers, etc. and can be broken down into separate components associated with key investment drivers as described in Table 4.3.

Table 4.3: Forecast Network Capex ($m, 06/07)

Capex Category		2007/08	2008/09	2009/10	2010/11	2011/12	Total	% of total
Load Driven	Augmentation	364.26	364.14	172.37	177.19	144.76	**1,222.71**	52
	Easements	20.31	15.70	11.59	19.24	37.22	**104.07**	4
	Connections	23.70	7.56	12.27	11.01	14.49	**69.03**	3
Non-Load Driven	Replacement	113.72	93.58	208.07	196.39	201.05	**812.80**	35
	Security / Compliance	2.63	33.02	23.38	37.00	19.82	**115.85**	5
	Other	2.64	7.36	5.51	5.32	0.23	**21.06**	1
Total		**527.25**	**521.36**	**433.18**	**446.16**	**417.57**	**2,345.52**	**100**

Source: Powerlink Revenue Proposal, Information Templates - Table 4.1

Table 4.3 shows that load driven investment accounts for almost 60% of the network capex forecast and non-load driven investment accounts for the remaining 40%. If there was no load growth over the next regulatory period, Powerlink could still be seeking up to $950 million for asset replacement, security/compliance and other non-load driven needs of the existing system.

Powerlink's load driven network capex is reviewed in Section 4.4 and its non-load driven network capex in Section 4.5.

4.2.2 Non-Network Capex

Non-network related capex comprises approximately 4% of the total forecast capex in the next regulatory period. It includes business related expenditure for information technology (IT) systems, buildings, vehicles and tools, etc. Powerlink's forecast for non-network capex in the next regulatory period can be broken down as shown in Table 4.4.

Table 4.4: Non-Network Capex Forecast ($m, 06/07)

Type of expenditure		2007/08	2008/09	2009/10	2010/11	2011/12	Total
Business IT	IT	11.90	11.20	11.05	10.89	12.34	**57.38**
Support the Business	Buildings	2.57	5.70	6.21	3.60	1.54	**19.61**
	Motor Vehicles	2.69	2.92	4.22	4.37	4.32	**18.51**
	Tools	1.89	1.85	1.44	1.49	1.55	**8.22**
Total		**19.05**	**21.65**	**22.92**	**20.33**	**19.7**	**103.72**

Source: Powerlink Revenue Proposal, Information Templates - Table 4.1

Powerlink's non-network capex is reviewed in Section 4.6.

4.2.3 Capex by Asset Class

The forecast capex can alternatively be broken down by asset class as shown in Table 4.5, which shows that approximately 89% of Powerlink's total capex forecast will be based on transmission line and substation infrastructure.

Table 4.5: Forecast Capex broken down by Asset Class ($m, 06/07)

Asset Class	2007/08	2008/09	2009/10	2010/11	2011/12	Total	% of total
Transmission Lines (overhead)	230.05	269.24	182.61	197.59	107.14	**986.62**	40.3
Transmission Lines (underground)	11.24	18.26	26.73	13.13	66.99	**136.34**	5.6
Substations Primary Plant	198.48	158.59	145.43	98.56	93.95	**695.01**	28.4
Substations Secondary Systems	58.00	41.51	55.67	91.38	103.72	**350.27**	14.3
Communications (buildings, towers and site infrastructure)	0.10	4.41	0.20	4.05	0.10	**8.86**	0.4
Communications (other assets)	8.65	13.40	10.95	22.21	8.45	**63.67**	2.6
Network Switching Centres	0.42	0.26	0.00	-	-	**0.68**	0.0
Easements	20.31	15.70	11.59	19.24	37.22	**104.07**	4.2
Land	0.26	0.26	0.26	0.26	0.26	**1.29**	0.1
Commercial Buildings	2.57	5.70	6.21	3.60	1.54	**19.61**	0.8
Computer equipment	11.90	11.20	11.05	10.89	12.34	**57.38**	2.3
Office Furniture, Misc.	0.15	0.15	0.15	0.15	0.15	**0.77**	0.0
Vehicles	2.69	2.92	4.22	4.37	4.32	**18.51**	0.8
Moveable Plant	1.48	1.44	1.03	1.08	1.14	**6.16**	0.3
TOTAL	**546.3**	**543.04**	**456.1**	**466.51**	**437.32**	**2449.24**	**100**

Source: Powerlink Revenue Proposal, p. 82

4.3 REVIEW METHODOLOGY

When reviewing Powerlink's forecast capex, a key issue was to determine whether the processes used to plan network requirements, optimise network utilisation and manage the timing, selection and implementation of investments are effective.

Our strategic review has therefore focussed on these aspects, and in accordance with our terms of reference as presented in Appendix A, we have:

1. reviewed Powerlink's capital governance framework and its capex strategies, policies and procedures to test their effectiveness and how well and consistently they are applied in practice. This is covered in Chapter 2 of this report;

2. reviewed the probabilistic approach used to develop the capex forecast to test the appropriateness of the inputs, scenarios and weightings and the resulting sensitivities to input assumptions. This has included consideration of the demand forecasts used to develop the Revenue Proposal;

3. undertaken a high-level review of the proposed capex forecast to examine the key factors driving the forecast and how the expenditure is allocated based on project and asset categories and geographic locations. At a high-level we have also considered project cost estimating and timing (this is covered in Chapter 2 and also in Section 4.8) and how the capex impacts on operation and maintenance activities (this is covered in Section 5.5.11);

4. undertaken a detailed review of specific projects from each of the main capex categories to critically evaluate whether or not:

- a project aligns with Powerlink's strategic plans and governance arrangements and that capex policies and procedures have been adhered to;
- there has been adequate assessment of the need for the project, given Powerlink's regulatory and statutory obligations and whether that need is genuine;
- a complete range of feasible alternatives has been considered; and
- the preferred project's timing, cost and scope are efficient, appropriate and reasonable.

In the cases where our review has led to the conclusion that the need, cost, scope or timing of a specific project is not prudent or efficient, we have recommended an adjustment;

5. examined the contingent projects in the Revenue Proposal to test whether they are appropriately classified as contingent projects based on the criteria set out in the SRP and that their trigger events are appropriate. We have also assessed the likelihood of the proposed contingent projects occurring in the regulatory period and whether there are any investments in the main ex-ante cap that would be more appropriately classified as contingent projects; and

6. examined the ability of Powerlink to deliver its forecast capital expenditure program given the demand for resources and materials for infrastructure projects in Australia at present.

The remaining sections of this chapter generally follow our review methodology, and they have been structured to address:

- demand driven network capex;
- non-demand driven network capex;
- non-network capex;
- contingent projects;
- the cost accumulation process; and
- Powerlink's ability to deliver the capital program.

4.4 DEMAND DRIVEN NETWORK CAPEX

4.4.1 General

As part of its forecast capex program, Powerlink has identified network related projects in two distinct categories - 'common' projects that are expected to occur at a specific time and in all the potential scenarios and 'variable' projects that are associated with one or more of the considered scenarios and for which the timing may vary between scenarios. These projects have been separately identified in Powerlink's information templates.

In total, 168 common projects and 239 variable projects are explicitly identified in accordance with Powerlink's information templates submitted to the AER in support of its Revenue Proposal and in accordance with the categories in Table 4.6.

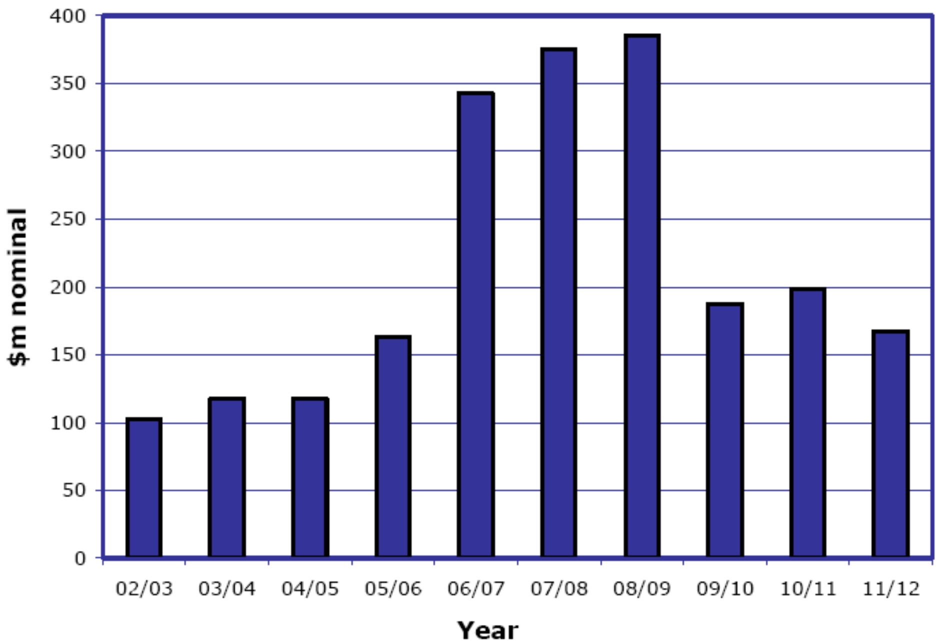
Table 4.6: Number of Forecast Network Capex projects

Project type	Common		Variable	
	Not WIP	WIP[1]	Not WIP	WIP[2]
Augmentation	6	20	119	10
Connection	1	7	33	5
Easement	34	5	62	8
Other	10	3	-	-
Replacement	61	18	-	-
Security/compliance	3	-	2	-
Total	**115**	**53**	**216**	**23**

Source: PB Associates
Note 1 - Refers to projects that are 'works in progress' at the start of the next regulatory period.
Note 2 – Assuming the project commissioning date is the median of the earliest and latest possible.

The majority of Powerlink's forecast capex over the forthcoming regulatory period, (52% or $1,222.71 million) is related to augmentations. An augmentation is defined in the NER as works to enlarge a network or to increase the capability of a network to transmit or distribute active energy. In accordance with clause 5.6.6 and clause 5.6.6A of the NER, all augmentations must be shown to satisfy the Regulatory Test, as promulgated by the AER. Powerlink is projecting a considerable increase in its augmentation related capex over the three year period 2006/07 to 2008/09, as seen in Figure 4-1. Powerlink has developed its augmentation capex forecast through the application of proven transmission planning techniques, as discussed in Section 4.4.3.3, and based on its published Planning Criteria Policy, as discussed in Section 2.4.

Figure 4-1: Historic and Forecast Expenditure on Augmentations



Source: Powerlink Revenue Proposal, p65

It can be seen from Figure 4-1 that there is a considerable increase in augmentation capex over the 2006-09 period, and this is discussed further in Section 4.4.3.4. The general increases in the capex forecast have been attributed by Powerlink as resulting from:

- significant increases in actual and forecast demand, resulting in the need to respond to more reliability based project triggers, particularly in South East Queensland;
- the need for Powerlink to undertake more thorough analyses towards the end of the next regulatory period under the new ex-ante regime;
- increased cost of materials since the market is tending to be more of a seller's market compared to the historical buyer's market;
- increased labour costs;
- additional environmental obligations including new vegetation management requirements; and
- additional workplace safety obligations such as increased use of elevated work platforms.

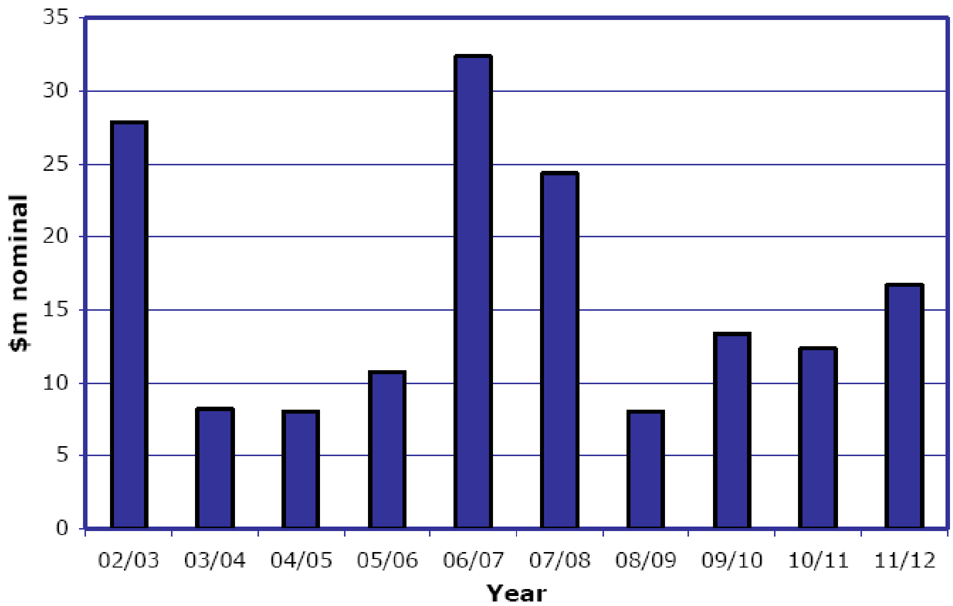
Powerlink's historic and forecast capex on network connections is shown in Figure 4-2. Network connection assets are used to connect customer assets to the shared network. While the provision of connection assets to new customers is unregulated, connection assets serving users of the network prior to introduction of the open access regime still form part of the RAB. These users include Energex, Ergon Energy, the large government owned generators and Queensland Rail.

Figure 4-2 indicates that the requirement for connection assets is cyclical, probably due to the fact that the assets cannot be added incrementally to match growth in demand. We also think that the significant increase in capex on both augmentation and connection assets over the period 2006-08 can be partly attributed to the release of the Somerville report[36] in 2004, where there were strong recommendations made regarding the planning approach adopted by the distribution business such as the use of 10% PoE forecasts[37] instead of 50% PoE forecasts, and the systematic application of an N-1 planning criteria.

[36] Queensland Department of Energy, July 2004, *Electricity Distribution and Service Delivery for the 21st Century,* Detailed report of the Independent Panel,

[37] Probability of Exceedence (PoE) forecast are discussed further in Section 4.4.2, relating to demand forecasts.

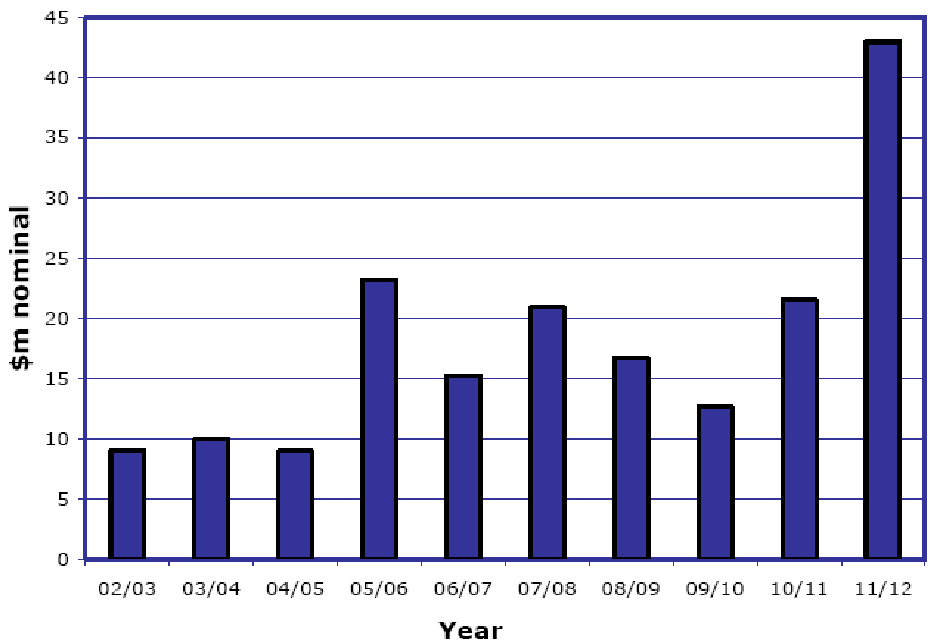
Figure 4-2: Historic and Forecast Expenditure on Connections



Source: Powerlink Revenue Proposal, p66

Historic and forecast capital expenditure on land and easements is shown in Figure 4-3. This includes expenditure on land and easements required for line and substation projects that are included in the forecast capex program. It also includes the acquisition of strategic land and easements. These are land and easement purchases that are not immediately required but are expected to be needed in the medium to longer term and where it is anticipated that changes in land use will result either in the land or easement not being available or in a significant increase in the cost, if the acquisition is deferred until the land or easement is actually required. The significant increase in proposed land and easement related capex in 2011/12 results from planned strategic acquisitions, in particular a planned 500 kV easement in South East Queensland.

Figure 4-3: Historic and Forecast Expenditure on Land and Easements



Source: Powerlink Revenue Proposal, p67

4.4.2 Demand Forecasts

The electricity demand and energy forecasts published in Powerlink's *Annual Planning Report* (APR) 2005 have been used to develop its load driven capex proposal. These forecasts are consistent with those used as part of NEMMCO's 2005 *Statement of Opportunities* (SOO) for the National Electricity Market (NEM). As these were the most recent and complete forecasts available at the time Powerlink prepared its Revenue Proposal, we consider it valid for Powerlink to have used them as the basis for its transmission planning.

4.4.2.1 Forecasting Process and Methodology

As described in Section 4.1 of Powerlink's APR 2005, the basis of Queensland's demand forecasts includes:

- historical demand as reviewed by DNSPs and directly connected customers;
- projected economic activity and growth (3 scenarios – high, medium and low);
- weather impact on demand patterns (3 scenarios – 10%, 50% and 90% probability of exceedence, (PoE));
- co-generation and renewable energy sources; and
- new committed connection point loads.

There are three different energy forecasts – one for each economic scenario, and nine different summer and winter peak demand forecasts - one for each combination of the three economic scenarios and the temperature scenarios. Powerlink presents its forecasts on the basis that they are "as-delivered" from the transmission grid. Such forecasts exclude resistive transmission network losses, power station auxiliary usage or generator transformer losses[38]. The forecasts are also presented based on the ten geographic zones defined by Powerlink.

The Queensland demand and energy forecasts are fundamentally derived on an annual basis using a "bottom-up" methodology. In accordance with Schedule 5.7 of the NER, DNSPs and directly connected customers provide ten-year forecasts at each of their individual supply points. These connection point forecasts are based on a review of the most recent summer and winter periods and detailed local knowledge of each connection point's historic and future demand, including any corrections for one-off operational demand transfers. They also form the key mechanism to ensure optimal joint planning for the transmission and distribution networks as they act as a common point of reference.

The "bottom-up" forecasts include medium growth 50% PoE conditions only. Powerlink aggregates these into a regional coincident forecast by applying suitable diversity factors[39] based on historical observations and then summating them. The diversity factors are an important characteristic of the Queensland forecasts as they capture the significant variations in conditions across the wide geographical region covered by the transmission network.

38 NEMMCO's SOO presents forecasts for all regions on an "as generated" basis, which includes the resistive transmission network losses and power station auxiliary usage or generator transformer losses. The conversion equations it uses to establish the "as generated" forecasts from the "as delivered" forecasts are detailed in Appendix B of the SOO and as an approximation the "as generated" forecasts are 1.12 times greater than the "as delivered" ones.

39 A diversity factor represents the ratio of a connection point peak demand compared with that which occurs at the time of the coincident state wide system peak.

PoE forecasts aim to capture the sensitivity of electricity demand to weather conditions, in particular ambient temperature. Records show strong correlations between ambient temperature and electricity demand, because when extreme hot or cold conditions occur, air-conditioning and other cooling and heating appliances operate with higher duties. A 10% PoE projection takes into consideration both the probability of extreme daily temperatures and the day of the week and is based on long-run average temperature records likely to be exceeded, on average, once every ten years.[40] Similarly, a 50% PoE projection is likely to be exceeded, on average, once every two years and a 90% PoE projections is likely to be exceeded, on average, nine out of every ten years. A 10% PoE effectively represents extreme weather and the 50% PoE represents average weather conditions. To establish the PoE projections, Powerlink accounts for the large geographic size and diverse weather conditions in Queensland by dividing demand into industrial and non-industrial categories and then sub-dividing the non-industrial demand into geographic zones to correlate the demand in these areas with local weather.

In addition to the “bottom-up” projections, Powerlink also engages the National Institute of Economic and Industrial Research (NIEIR) to provide a “top-down” assessment of energy and demand forecasts for the Queensland region on an annual basis. The “top-down” methodology extends the range of forecasts to include high and low economic growth forecasts and the 10% PoE and 90% PoE weather conditions. NIEIR’s forecasts also include an assessment of demand side management and embedded generation.

NIEIR, which was also engaged by NEMMCO in June 2005 to provide an update on the key factors affecting electricity of demand in the NEM[41] over the period 2005-2015, has identified the following key factors which it accounts for in its analysis:

- Economic growth;
- Evolution of the National Electricity Market (NEM);
- Commonwealth and State economic, energy and environmental policies;
- Competition from natural gas;
- Technological change.

The “top-down” forecast for medium growth and average weather conditions (medium, 50% PoE) is reconciled against the “bottom-up” approach by Powerlink. Through this validation and checking process, Powerlink finds that the two forecasts generally agree closely. As part of our review, Powerlink provided confidential information relating to the outcomes of the 2005 reconciliation process and advised on changes between the first draft of the “bottom up” forecasts for the 2005 APR and the final version. This information showed that the aggregate forecast was reduced to the levels published in the 2005 APR through the reconciliation process.

Powerlink is a member of the national Load Forecasting Reference Group (LFRG) which is convened by NEMMCO and is responsible for ensuring that the energy and maximum demand projections in the SOO (and APRs) are prepared on a consistent basis and use a common set of definitions. The working group includes representatives from each jurisdictional planning body, including Powerlink, and from NIEIR.

Further to the LRFG’s functions, in late 2004 NEMMCO engaged KEMA Inc. to review the load forecasting procedures used by the all jurisdictional planning bodies across the NEM, including Powerlink.

40 As an example, the 10% PoE reference temperature for Brisbane, as measured at Archerfield, is 30.5°C as sourced from Page 159 of Powerlink’s APR 2005.

41 NIEIR, 2005, *Factors affecting the electricity demand in the NEM - A report for the National Electricity Market Management Company*

The LFRG and KEMA Inc. identified that Powerlink has a unique approach to load forecasting in that it predominantly uses the bottom-up approach and then reconciles this with the top-down version. In its report[42], KEMA Inc. highlighted the importance of the reconciliation process since Powerlink does not review the methodology underlying the connection point forecasts. It also found that the overall approaches used by the various parties developing the Queensland demand and energy forecasts were sound, and combined good technical methods with good judgement and experience.

Drawing from our review of documentation published by Powerlink, NEMMCO, NIEIR and KEMA Inc., and discussion with Powerlink staff on forecasting outcomes, we agree that the general methodology applied by Powerlink is reasonable. However, we highlight that, because Powerlink simply applies ratios based on NIEIR's independent forecast for the high and low economic growth scenarios and the 10% and 90% PoE weather conditions to the "bottom-up" medium growth 50% PoE forecasts, there appears to be limited checks or validation on eight of the different forecasts.

4.4.2.2 Summer Peak Demand

In Queensland, summer peak demand conditions are the most onerous when considering the capability of the network to meet its required reliability standards. This is due to a number of key factors – the most important is that the summer peak demand (both real and reactive) is higher than in winter[43], the thermal transfer capability of the network plant is considerably reduced under higher temperatures[44], and duration of high demand during summer peak demand days is longer compared with winter days which are peakier[45].

On this basis, and in accordance with its planning criteria policy, Powerlink primarily takes into account summer peak demand when planning network augmentations. Due to the mandated reliability requirements in Powerlink's Transmission Authority, any inability of the network to meet all forecast peak summer demand under N-G-1 conditions is a trigger for the detailed review of augmentation options. The energy at risk (which accounts for the duration and magnitude of constraints, as measured in MWh) is only considered as a secondary matter and used when evaluating the benefits of alternatives being considered. Energy growth forecasts are more critical for generation planning as opposed to transmission planning. In Powerlink's case this appears reasonable as typically the high demand and energy growth characteristics tend to favour the development of large network augmentations over smaller, incremental alternatives or control schemes. Such alternatives only provide effective relief when demand and energy growth is relatively low, or when constraints are expected to be relieved over time by other means (e.g. by the planting of a new generator or by an associated augmentation project).

Figure 4-4 sets out the (as generated) 50% PoE peak summer demand forecasts in Queensland over the ten year outlook. These forecasts are consistent with the detailed connection point/bulk supply points forecasts used to develop Powerlink's forecast capex.

Growth in peak summer demand, as shown in Figure 4-5, is the key driver dictating the timing and quantity of Powerlink's forecast capex.

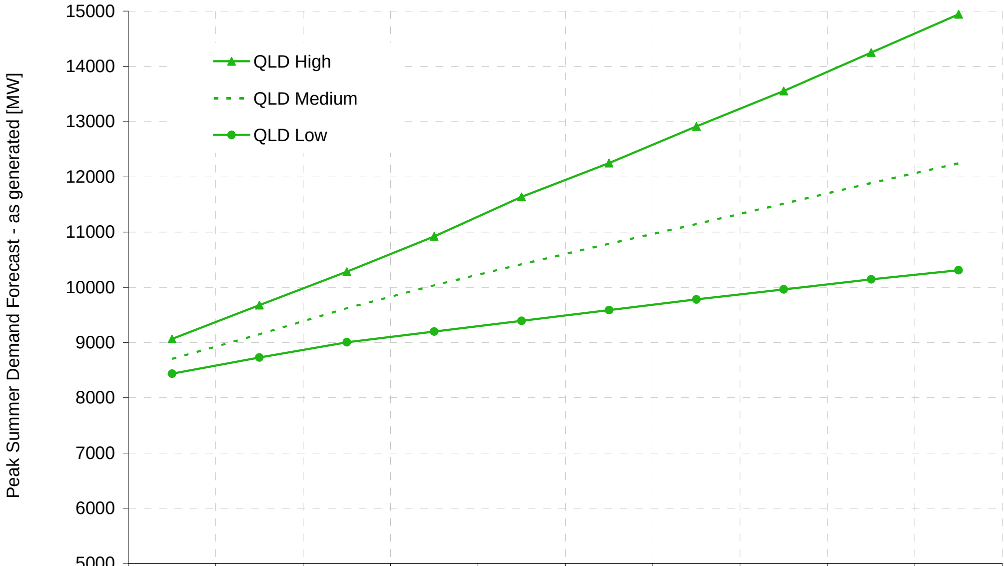
[42] KEMA Inc., Review of the Process for Preparing the SOO Load Forecasts, 17 June 2005.

[43] Peak summer demand in 2006/07 is forecast to be 114% higher (> 1000MW) than the previous 2006 winter peak demand.

[44] As an example, each circuit of a high capacity 275 kV transmission line has a thermal rating at 15°C ambient temperature that is 120% higher than that at an ambient temperature of 35°C.

[45] As evidenced by Figure 3.9: Summer and Winter Peaks 2005/06, on Page 42 of Powerlink's 2006 Annual Planning Review

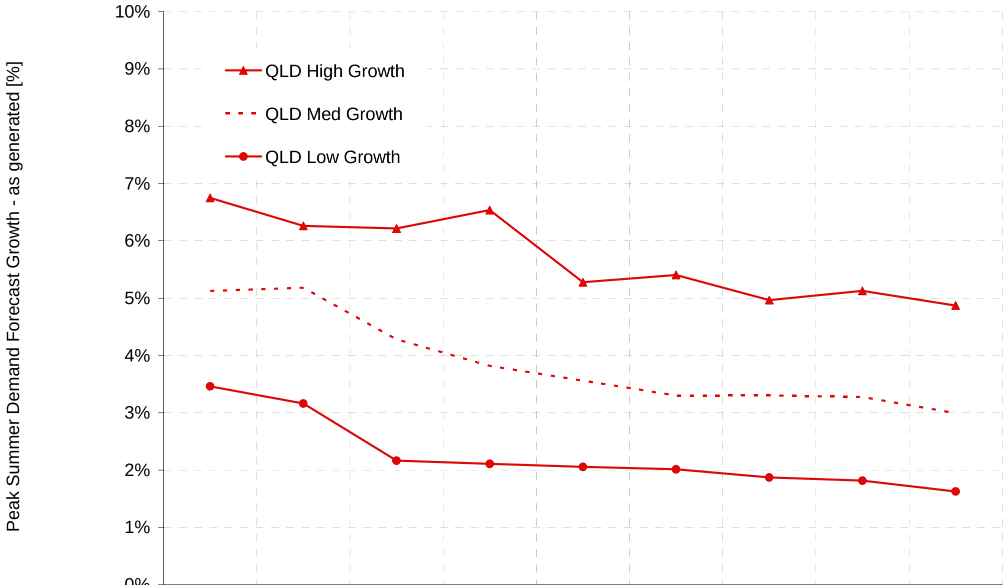
Figure 4-4: Peak summer demand forecasts used to develop Powerlink's forecast capex



	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
QLD High	9065	9677	10283	10922	11636	12250	12912	13553	14248	14942
QLD Medium	8702	9148	9622	10034	10417	10788	11144	11512	11889	12245
QLD Low	8437	8729	9005	9200	9394	9587	9780	9963	10144	10309

Source: NEMMCO's SOO 2005, Page 3-14

Figure 4-5: Growth in peak summer demand forecasts used to develop Powerlink's forecast capex.



	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
QLD High Growth	6.8%	6.3%	6.2%	6.5%	5.3%	5.4%	5.0%	5.1%	4.9%
QLD Med Growth	5.1%	5.2%	4.3%	3.8%	3.6%	3.3%	3.3%	3.3%	3.0%
QLD Low Growth	3.5%	3.2%	2.2%	2.1%	2.1%	2.0%	1.9%	1.8%	1.6%

Source: PB Associates, based on NEMMCO's SOO 2005, Page 3-14.

The figures indicate that over the regulatory period, the annual summer peak demand growth is on average 635 MW, 400 MW and 215 MW for the high, medium and low growth scenarios, respectively. These values also represent the typical levels of new generation required over the next regulatory period in each scenario in order to maintain similar levels of generation reserve as exist at the start of the period.

Figure 4-5 indicates that the forecast demand growth in Queensland, while still higher than in other regions of Australia, will generally reduce under all scenarios over the regulatory period. It reduces from 5.2% at the start of the next regulatory period to about 3.3% by the last year of the period under the medium growth scenario.

From the forecasts, the observed temperature sensitivity of daily peak demands over the 2004/05 summer period in Queensland is in aggregate 181 MW per °C. This has increased considerably from around 77 MW per °C over the 1997/98 summer period, supporting NIEIR's finding that air-conditioning and temperature dependent loads are increasing. It is important to note that this sensitivity primarily applies towards the extreme temperature conditions. This sensitivity is relatively low compared with the Victorian, South Australian and New South Wales figures[46] when normalised for the demand in each state.

NEMMCO confirms this observation by noting that Queensland's maximum demand varies significantly less between the average and extreme years when compared to maximum demand variations in New South Wales, Victoria and South Australia, as shown in Table 4.7.

Table 4.7: Effect of Weather on Maximum Demand projections for Summer 2005/06 (MW)

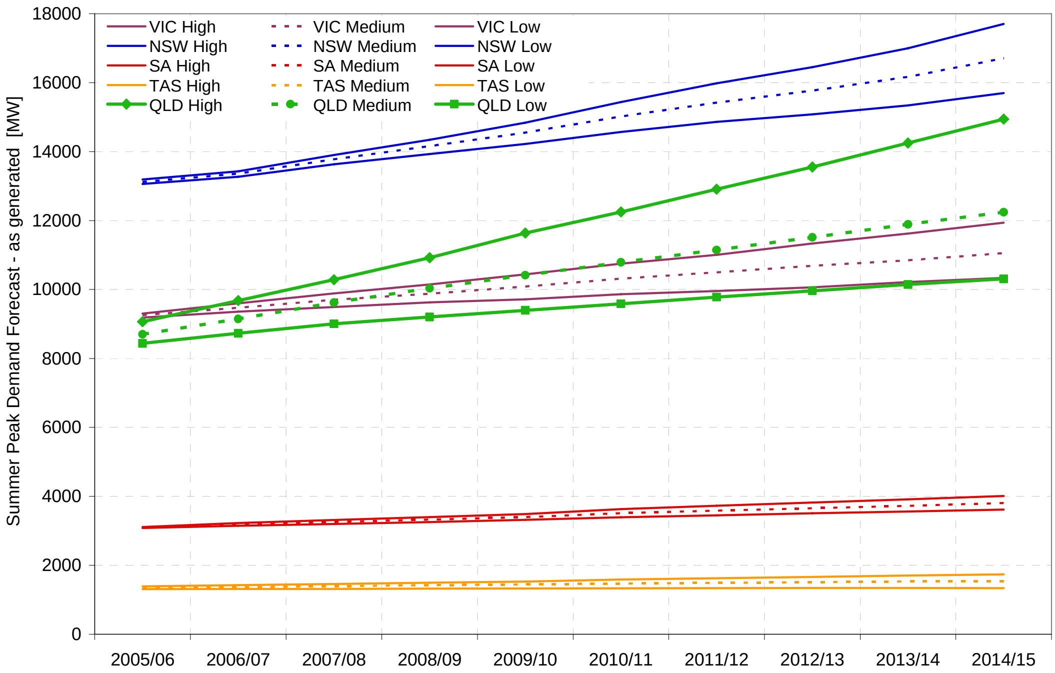
Region	Average Summer Weather Demand (50% PoE)	Extreme Summer Weather Demand (10% PoE)	Difference	Per cent change, %
Queensland	8702	9046	344	4.0
New South Wales	13120	14080	960	7.3
Victoria	9260	10119	859	9.3
South Australia	3091	3378	287	9.3
Tasmania	1346	1364	18	1.3

Source: NEMMCO's "2005 Energy and Demand Projections – Summary Report", July 2005, page 3 and PB Associates for Column 4.

As shown in Figure 4-6, the Queensland summer peak demand forecasts over the next regulatory period and beyond are more difficult to predict accurately than in other regions of the NEM, even in the early years of the period. For instance, in the first year of the forecast, peak summer demand cannot be predicted more accurately than a range of 630 MW based on variation in economic growth scenarios. The range is even wider (1,180 MW) if the weather and temperature variances are taken into account. This uncertainty tends to support Powerlink's use of a probabilistic scenario based approach to capex forecasting that allows the sensitivities to growth rates to be identified and captured in the forecasting process.

46 As determined by demand forecasts and reference temperatures described in Section 3.3 and 3.5 of NEMMCO's *2005 Statement of Opportunities*

Figure 4-6: Comparison of Demand Forecasts for NEM regions.

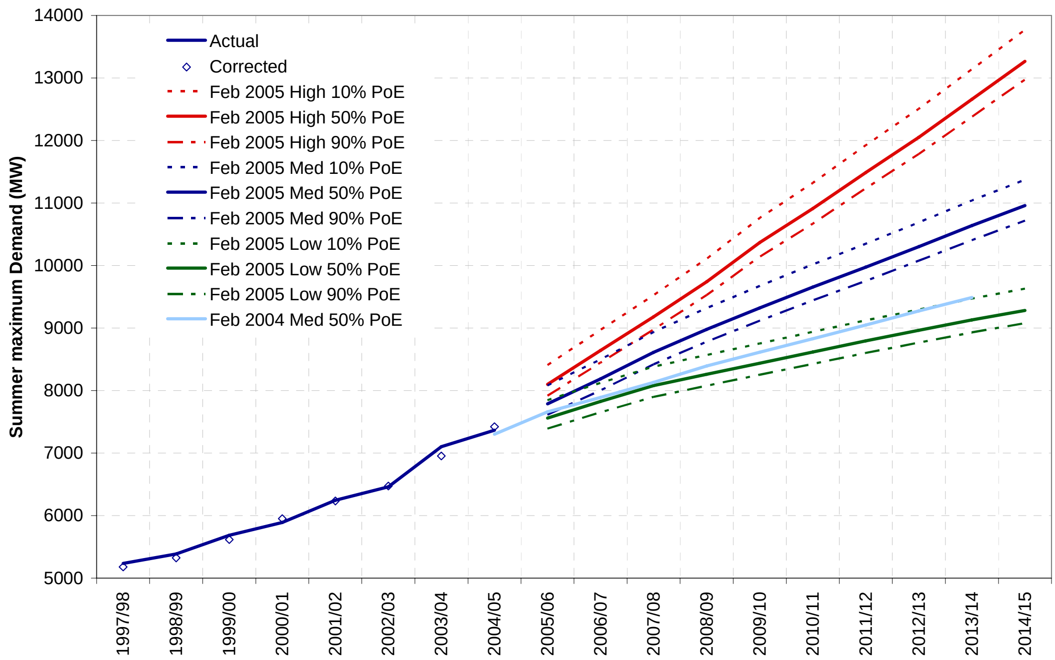


Source: PB Associates and NEMMCO's SOO 2005.

4.4.2.3 Significant Update to Queensland Demand Forecasts in APR 2005

As evident in Figure 4-7 and Table 4.8, there was a significant change in the peak summer demand forecasts in Queensland between the publication of the 2004 and the 2005 APRs. This is reflected in an increase in the 2007/08 medium 50% PoE forecast of 480 MW.

Figure 4-7: Analysis of Summer Demand Forecasts



Source: Powerlink (2005 APR p34)

Table 4.8: Adjustment to zone forecasts for Medium 50% PoE summer maximum demand in 2007/08 between 2004 and 2005 APR.

Geographic Zone	Change in Forecast from 2004 to 2005 MW
Far North	4
Ross	2
North	-26
Central	-6
Gladstone	43
Wide Bay	-1
South West	50
Moreton North	277
Moreton South	10
Gold Coast/Tweed	127
TOTAL	**480**

Source: PB Associates

Powerlink has advised that the basis for the significant correction to its 2005 demand forecast was related to the factors listed below:

- The aggregate summer 2004/05 peak demand of 7,368 MW (being 7,424 MW temperature and diversity corrected) significantly exceeded the 2004 forecast of 7,303 MW.

- Energex and NIEIR both revised their forecasts to reflect a belief that the South East Queensland domestic air-conditioning boom would continue for a further two years, particularly as air conditioning unit prices had fallen substantially. Less dramatic, but still significant, increases were also forecast for other parts of Queensland.

- Record demands were experienced in South East Queensland during February 2004, confirming NIEIR's advice that air-conditioning purchases throughout 2003 were substantially higher than the already record expectations, and that cumulative simultaneous air-conditioning loads could occur under very hot conditions.

- Population growth in Queensland had spiked to around 2.3% to 2.5% over the previous two years and the future population growth rate was revised upwards to just over 2% per annum. This was particularly relevant to South East Queensland where the ten-year average energy growth has increased from 3.4% to 4.2% per annum.

- NIEIR increased the ten-year outlook for Queensland gross state product over all (low, medium and high) growth scenarios.

- A new coal handling plant at Gladstone had become committed.

- Significant expansion in coal mining activity, and associated railway and port handling facilities was now forecast by DNSPs and NIEIR.

- A new industrial load near Swanbank was included.

- Minor demand increases were allowed for in existing aluminium and zinc smelter plant.

- Goondiwindi Shire, previously supplied from NSW, was now included in the forecast due a new 132 kV supply from the South West Queensland grid.

Powerlink has further advised that the increased 2005 forecast has been validated by the following:

- Department of Energy / Energex surveys conducted in May 2004 and May 2005 show that domestic air-conditioning penetration in South East Queensland reached 45% and 56% respectively at those times. The 2004 result confirmed the level of the earlier three year boom, but the 2005 result was well above the prediction. This was consistent with NIEIR air-conditioning sales information.

- Respondents to these surveys also indicated substantial further short term air conditioning penetration increases and an expectation of widespread future upgrades of older air conditioning systems or the addition of further units.

- Powerlink's observations from plots of demand against ambient temperatures have shown substantial increases in sensitivity on working weekdays, and even more so on weekends and holidays, which it considers is directly related to levels of domestic air-conditioning.

While the magnitude of the peak summer demand correction between the 2004 and 2005 APRs was significant and unusual over a single year, we consider it is justified given the deliberation and the reasons outlined by Powerlink. The location based corrections outlined in Table 4.8 also support Powerlink's review, as it can be seen that the significant variations are in South East Queensland.

4.4.2.4 Consideration of Summer 2005/06 Experience and APR 2006 Forecast

While undertaking our review, Powerlink published its 2006 APR, which included an update of energy and demand forecasts in Queensland after taking into account winter 2005 and summer 2005/06 consumption and demand. We consider the consistency of the actual demands through these periods compared to the 2005 APR forecasts as an important check on the validity of the one-off correction in forecasts between 2004 and 2005, and therefore the forecast capex determined by Powerlink.

As part of the new forecasts, there appears to have been a one-off correction for demand in the Gold Coast/Tweed zone, where the Tweed Shire demand of approximately 90 MW is no longer defined as part of the Queensland region and has therefore been removed from Powerlink's forecasts. The change came about as a consequence of a regional boundary change following the conversion of DirectLink to a regulated transmission network asset. As a result of this change the Tweed Shire load is now forecast and reported as part of Northern NSW. However, Powerlink has advised there has been no physical change to the supply arrangement for the Tweed Shire demand, and Country Energy still requires Powerlink to plan the transmission grid to meet this load, so there appears to be no impact on Powerlink's forecast capital expenditure requirements. This definitional correction makes it difficult to make a direct comparison between the 2004 and the 2005 Queensland demand forecasts.

Excluding the Tweed Shire demand, the actual 2005/06 peak summer demand in Queensland was 7,388 MW. This figure also excludes supply to a 20 MW smelter that was forecast but did not eventuate. The actual peak summer demand in 2005/06 was 313 MW lower than the Tweed Shire-adjusted medium growth scenario 50% PoE forecast in the 2005 APR of 7,701 MW. Consistent with previous reviews, Powerlink undertook a temperature sensitivity and diversity factor review. It observed that the temperature sensitivity increased from 181 MW / °C to 245 MW / °C, and that the increase was predominantly in the South East zone. Furthermore, it identified the need for considerable temperature and diversity correction as outlined in Table 4.9.

Table 4.9: Overview of zone based demands and correction for summer 2005/06 (MW)

Zone	Actual demand at system peak	Actual non-coincident peak	50% PoE temperature corrected non-coincident peak	APR 2005 50% PoE medium forecasts, non-coincident	Historic average diversity %	Temperature and diversity corrected demand
South East	4,033	4,149	4,251	4,237	100	4,251
South West	351	401	406	394	93.7	380
Northern (no industry)	1,041	1,140	1,137	1,103	93.7	1,065
Central (no industry).	909	925	968	977	92.6	896
Major industrials	1,054	1,141	1,141	1,201	95.7	1,092
TOTAL	**7,388**	**7,756**	**7,903**	**7,912**	**-**	**7,685**

Source: Powerlink

Key observations from this assessment are that:

- the temperature and diversity corrected demand of 7,685 MW was only marginally lower than the forecast of 7,701 MW; and
- the temperature corrected diversity factors in the South East and South West zones were lower than historical averages – 4033/4251 = 94.9% and 351/406 = 86.5%, respectively.

Without having reviewed and verified the actual temperature or demand records, we consider that the review undertaken by Powerlink has been rigorous and is consistent with previous practices. Our main concern is with the determination of the temperature sensitivity factors and the validity of applying these to demand levels that were below the 50% PoE demand level, as we consider the temperature sensitivity would not necessarily be linear across widely varying temperature conditions.

Powerlink also identified overall changes in the medium scenario, 50% PoE summer peak demand forecast as shown in Table 4.10.

Table 4.10: Revised peak summer demand forecasts, excluding Tweed Shire (MW)

Source	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
APR 2005	8095	8514	8878	9216	9543	9857	10181	10515
APR 2006	8230	9615	8990	9315	9624	9937	10255	10585
Increase	135	101	111	99	80	80	74	69

Source: Powerlink

4.4.2.5 Conclusions on Powerlink's Demand Forecasting

We consider Powerlink used the most recent and appropriate forecasts when undertaking its grid planning as part of its Revenue Proposal.

At a high level, the forecast methodology, including its temperature and diversity correction aspects, appears reasonable on the basis of the considerable effort and analysis carried out and discussed as part of each year's APR preparation.

However, we suggest that the AER should consider undertaking some form of additional review of Powerlink's forecasts - similar to the backcasting exercise undertaken by NIEIR for the Victorian and South Australian regions[47] - to assess the accuracy of Powerlink's summer maximum demand forecasting outcomes. We consider such a review is justified by:

- the very high sensitivity of the forecast capex to the demand forecasts, as discussed in Section 4.5.2;
- the limited checks and verification of the high and low economic growth scenarios;
- our limited understanding of the role an independent observer such as NIEIR plays in the temperature correction process for Queensland, and the validity of applying the highest temperature sensitivity across a wide range of temperature conditions;
- the difficulty in accurately forecasting summer peak demand, as evidenced by the wide spread in the summer peak demands across the nine types of forecasts compared with other regions, particularly in the short term;
- the large and increasing impact (~300 MW) of the diversity and temperature corrections for summer 2005/06, in particular the significant increase in the observed temperature sensitivity of daily peak demands (up to 245 MW per °C compared with 181 MW per °C in summer 2004/05);
- limited evidence to support the major changes in the 2006 APR compared with the 2005 APR of +164 MW for the 10% PoE summer demand in 2006/07, and the -268 MW reduction for the 10% PoE winter demand in 2007; [48]
- our difficulty in understanding the reasons for the inconsistent presentation of historic actual and 50% PoE temperature/diversity corrected summer peak demands from 1998/99 to 2004/05 between the 2005 and 2006 APR's; and
- the timing of KEMA's methodology review, which appears to have been prior to the significant correction between the 2004 and 2005 APR forecasts.

4.4.3 Probabilistic Planning Approach

4.4.3.1 Introduction

To address the uncertainties related to future load growth and generation developments, and consistent with the SRP, Powerlink has adopted a probabilistic scenario-based method for determining a range of probable generation and transmission developments over the next regulatory period. The methodology used is similar to that applied by Powerlink in its 2001 Revenue Proposal. It aims to capture the sensitivity of transmission network development to market outcomes and key investment drivers.

This scenario based approach allows Powerlink to prepare rigorous transmission development plans across a range of foreseeable scenarios. A similar, albeit less comprehensive, approach is used to develop annual transmission plans, which are updated annually and form an integral part of Powerlink's ongoing business planning processes by feeding into its capital expenditure forecasts, its APR and NEMMCO's SOO.

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47 NIEIR, June 2005, *An assessment of the forecasting accuracy of the current summer MD forecast methodology for Victoria and South Australia: A backcasting exercise.*

48 Changes are referenced from NEMMCO's *2006 Energy and Demand Projections – Summary Report*

The probabilistic approach is used to forecast demand and generation driven capex requirements, including augmentations, easements and connections, which comprise approximately 60% of the total forecast capex.

Powerlink engaged specialist market modelling consultants ROAM Consulting[49,50] to undertake the probabilistic generation forecasting work. The focus of the ROAM approach was on determining the quantity and location of new generation to meet forecast demand growth, given certain assumptions about reserve margins and other market and non-market based influences.

The approach includes three key dimensions:

1. Developing top-down market wide theme sets to reflect the changing environment;
2. Developing bottom-up prospective generation development projects; and
3. Identifying prospective generation projects and their optimal timing within each scenario.

In implementing this approach, ROAM Consulting undertook the following key steps:

- Identification of high level variables that would impact on the development of new generation within Queensland using theme sets and theme probabilities;
- Scenario development based on the permutations and combinations of themes;
- Calculation of top-down scenario rankings based on the product of each theme's probability;
- Identification of possible generation development projects and retirements;
- Population of each scenario with generation projects given the theme conditions and assumption about reserve margins, etc;
- Calculation of bottom-up rankings for each scenario given the stream of generation projects identified;
- Determination of an overall scenario probability given the top-down and bottom up rankings; and
- Moderation of scenario probabilities based on reserve margin criteria and generation capacity factors.

4.4.3.2 *Theme Sets*

ROAM Consulting also undertook an extensive review of documentation from a multitude of sources (including both public and confidential information) in developing the key theme sets, their implicit generation projects and the applicable weightings.

These theme sets are described in further detail in Table 4.11 and are made up of:

1. Demand growth, which specifically accounts for annual energy and summer demand growth on a geographical basis;

[49] ROAM Consulting, 2005, *NEM Forecasting – Identification of Generation Development Scenarios.*

[50] ROAM Consulting, 2005, *NEM Forecasting – Scenario Analysis Revisions for PNG Pipeline Developments*.

2. Inter-regional trade, which accounts for the potential impact that expanded interstate trading may have on electricity transmission infrastructure development;

3. Gas supply, to highlight the variability in new generating plant technologies and locations as influenced by the development of a gas pipeline from Papua New Guinea; and

4. Greenhouse options, to highlight the impact carbon taxes may have on existing (coal fired) or new (biomass) generating plant.

The demand growth theme set is the primary theme set which captures the key influence of projected demand and energy variations. ROAM Consulting considers the rate of growth in energy demand across the state will be a major contributing factor to the development of new generation plant as the new entrants need to ensure that the energy generated will be consumed by the market. It also considers that the growth in peak demand will have a bearing on the type of plant (i.e. base load or peaking plant) developed. It has considered each of these factors when determining the generation planting for each scenario.

The secondary theme sets of inter-regional trade and gas supply only influence changes in generation developments in the last two years of the next regulatory period (2010/11 and 2011/12) and beyond, while the greenhouse options theme set introduces small variations in generation planting as early as 2008/09 with increasing impact over the remainder of the next regulatory period.

Table 4.11: Probabilistic Themes Adopted by Powerlink

Theme Set	Themes	Initial Probability	Adjusted Probability
Load growth	Low Growth, 50% POE	20%	**23.93%**
	Medium Growth, 50% POE	35%	**37.09%**
	Medium Growth, 10% POE	25%	20.74%
	Medium Growth, 50% POE, plus 500 MW prior to 2009/10 and further 500 MW prior to 2010/11	10%	**10.97%**
	High Growth, 50% POE	10%	7.28%
Inter-regional trade	Existing QNI transfer of 300 MW to Qld.	70%	65.50%
	Increased QNI transfer (+500 MW to Qld) prior to 2010/11	30%	**34.50%**
Gas supplies	No PNG pipeline driven generation development	50%	**53.54%**
	New generation (but no load) development associated with PNG pipeline timing prior to summer 2010/11.	50%	46.46%
Greenhouse options	No Greenhouse tax	80%	**87.24%**
	Introduction of greenhouse tax	20%	12.76%

Source: Powerlink

The adjusted probabilities shown in Table 4.11 were determined by ROAM Consulting following additional analysis that took into account the uncertainty relating to actual generation projects within each theme, the expected bounds of reserve plant margins, and the expected bounds of power station sizes. Red coloured (bold) weightings have increased, while green coloured weightings have decreased.

The purpose of the initial and adjusted probabilities is to quantify the relative likelihood of one theme occurring relative to another. ROAM Consulting has placed a very high combined weighting (approximately 70%) on the likelihood of the medium load growth scenario and its variants proceeding. This is on the basis that this scenario best reflects the long run average growth in peak-to-peak demand in Queensland. We concur with this position and acknowledge that growth is increasing, but highlight that the average annual load growth under the medium growth theme in the 2005 APR is relatively high compared with previous experience and previous APRs[51].

The use of the medium growth 10% PoE forecast aims to capture the effect of extreme weather impacts and the resulting increase in air-conditioning load in the domestic sector and it has a similar initial weighting (25%) when compared to the medium growth 50% PoE forecast (35%), which reflects average temperature conditions. We consider this weighting is appropriate and reasonable given the industry tendency to use 1/3:1/3:1/3 weightings for 10%, 50 % and 90% PoE scenarios[52] and the outcomes of the probabilistic approach as discussed in the following section.

We have given some consideration as to the appropriateness of applying the same weighting to each theme for all years in the review period, that is, should the weighting of the high growth scenario be constant at 7.28% in all years or increase with time to reflect greater uncertainty. While this may have some merit, we have concluded that it would not make a material difference to the final outcome.

4.4.3.3 Planning Process for Demand Related Network Capex

By combining each of the themes in the four sets (5 x 2 x 2 x 2), 40 separate grid development scenarios have been identified. ROAM Consulting identified explicit generation planting programs for each of these 40 scenarios, based on its assessment of the impact that each of the non-load related theme sets would have on generation development. Our review of these programs is outlined in Appendix G.

In order to capture all foreseeable capex over the 2007-12 regulatory period Powerlink has undertaken detailed transmission planning studies out to 2015/16 assuming the relevant generation planting program developed by ROAM Consulting. This approach ensures the capture of early capex for construction projects where expenditure may be required up to four years prior to commissioning. This is necessary now that expenditure is recognised in the year that the expenditure is incurred rather than on an as commissioned basis.

For each of the 40 scenarios identified, Powerlink has determined an explicit and deterministic program of projects in accordance with the following process.

For each of the 10 geographical transmission grid zones in Queensland, and for each of the 40 scenarios identified, and for each of the study years in chronological order, Powerlink carried out the following steps;

- Created a full alternating current (AC) mathematical load flow model to simulate the operation of the integrated power system, including any projects identified through the previous years' analysis;
- Predicted the future loadings on the transmission network given the load forecast scenario and economic generation / inter-connector dispatch in accordance with its planning criteria;
- Assessed the network loading and utilisation during credible contingencies and compared this against network capability in accordance with its planning criteria;

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51 As depicted in the figure on Page 16 of the ROAM Consulting, 2005, *NEM Forecasting – Identification of Generation Development Scenarios* report.

52 These weightings have typically been adopted to preserve the moments of a normal distribution when converting it to a three value discrete distribution – refer Allen Miller and Thomas Rice published in the Management Science Journal in March 1983 entitled "Discrete Approximations of Probability Distributions".

- Identified constraints and limitations;
- Identified alternatives to alleviate the constraints; and
- Identified the preferred network development option through least cost planning consistent with the reliability limb of the regulatory test.

The outcome from this process was a deterministic transmission plan for each of the 40 scenarios, resulting in an explicit annual project program and associated capex requirement over and beyond the review period. These transmission plans include a total of 407 separate prospective transmission network projects that are included in the formulation of its capex forecast.

Powerlink has adopted a full network model and AC power flow solution (through the combination of a direct current (DC) power flow algorithm followed by an optimal power flow algorithm) as part of its deterministic transmission planning for each scenario. Powerlink considers this approach is a significant improvement on that used for its 2001 revenue application, which was based on a reduced network model and DC power flow solution only. We concur with this statement and consider Powerlink has adopted a rigorous and systematic approach to identifying constraints, which now captures the important effects of parallel transmission/subtransmission paths and reactive power flows. In our opinion, it is likely that this more detailed approach, combined with the required rigour of an ex-ante ‘as incurred’ regulatory model, has resulted in the identification, or at least the advancement, of a number of projects that may not have otherwise been proposed using a less thorough approach. This, in combination with the wide variance in the forecasts of underlying load growth in Queensland, has resulted in the large number of projects identified by Powerlink.

The results of this planning process are documented in Powerlink’s 2005 Grid Plan. These planning documents provide a comprehensive overview of the projects identified through the planning process but could be improved and supplemented with the addition of technical information relating to the need for each project (such as summaries of forecast power flows and overloads for critical plant over time, etc) and additional information on the alternatives considered. Such information was made available for this review on a project by project basis during discussions with Powerlink staff.

Notable elements of Powerlink’s demand driven planning process included:

- An extensive review of reactive compensation requirements to meet forecast active and reactive power demands;
- Joint planning with each of the distribution businesses to optimise technical solutions; and
- A review of easement requirements to identify both short term construction requirements and longer term strategic acquisitions.

We consider Powerlink’s planning process for identifying demand related network capex has been systematic, thorough and of a very high standard. We would be surprised if any system constraints within the considerable planning horizon were not identified, and Powerlink has endeavoured to ensure that all of its reliability obligations will be met. This has been evidenced by the comprehensive Grid Plan document, which is well supplemented by Powerlink’s 2005 APR and the considerable familiarity and knowledge of the network constraints offered by Powerlink’s planning staff during detailed project reviews.

4.4.3.4 Probabilistic Planning Outcomes

The deterministic transmission development plans prepared for each scenario were then costed by Powerlink's cost estimation group to provide an estimated capex requirement for each year of the next regulatory period for each of the 40 transmission plans. Powerlink then weighted the deterministic capex for each scenario plan by its adjusted probability of occurrence (on an "as incurred" basis) and summated these to arrive at an aggregate probabilistic weighted forecast capex. We note that this technique has specifically been used a tool for the purposes of producing Powerlink's regulatory capex forecast and that it does not form part of Powerlink's ongoing business planning processes.

The 40 scenarios for which transmission plans were developed and the relative probability weightings assigned to each, are shown in Table 4.12, which indicates that:

- the top three weighted and ranked scenarios are 9, 11 and 1, respectively, which are associated with medium and low growth scenarios;
- the highest ranked high growth scenario is only the 15th most likely scenario to proceed; and
- the medium growth scenarios of 9 and 11 are between 34 and 50 times more likely to proceed compared to the four least likely scenarios, which are all based on the high growth theme.

The deterministic 'as incurred' capital expenditure identified by Powerlink for each of the 40 scenarios is presented on an annual basis in Table 4.13.

Table 4.12: Probabilistic Scenarios Adopted by Powerlink

Scenario	Load Growth	Inter-regional trade	Gas Supplies	Greenhouse options	Base weighting[1]	Adjusted weighting[2]
1	L50	QNI	No PNG	No Tax	5.60%	**7.88%**
2				Tax	1.40%	1.10%
3			PNG	No Tax	5.60%	**6.78%**
4				Tax	1.40%	1.10%
5		QNI++	No PNG	No Tax	2.40%	**3.79%**
6				Tax	0.60%	0.50%
7			PNG	No Tax	2.40%	2.29%
8				Tax	0.60%	0.50%
9	M50	QNI	No PNG	No Tax	9.80%	**10.87%**
10				Tax	2.45%	1.50%
11			PNG	No Tax	9.80%	**10.07%**
12				Tax	2.45%	1.50%
13		QNI++	No PNG	No Tax	4.20%	**5.88%**
14				Tax	1.05%	0.90%
15			PNG	No Tax	4.20%	**5.58%**
16				Tax	1.05%	0.80%
17	M10	QNI	No PNG	No Tax	7.00%	6.68%
18				Tax	1.75%	0.80%
19			PNG	No Tax	7.00%	4.89%
20				Tax	1.75%	0.70%
21		QNI++	No PNG	No Tax	3.00%	**3.79%**
22				Tax	0.75%	0.50%
23			PNG	No Tax	3.00%	2.89%
24				Tax	0.75%	0.50%
25	M50++	QNI	No PNG	No Tax	2.80%	**3.39%**
26				Tax	0.70%	0.40%
27			PNG	No Tax	2.80%	**2.89%**
28				Tax	0.70%	0.40%
29		QNI++	No PNG	No Tax	1.20%	**1.69%**
30				Tax	0.30%	0.30%
31			PNG	No Tax	1.20%	**1.60%**
32				Tax	0.30%	0.30%
33	H50	QNI	No PNG	No Tax	2.80%	1.99%
34				Tax	0.70%	0.30%
35			PNG	No Tax	2.80%	1.99%
36				Tax	0.70%	0.30%
37		QNI++	No PNG	No Tax	1.20%	1.10%
38				Tax	0.30%	0.20%
39			PNG	No Tax	1.20%	1.20%
40				Tax	0.30%	0.20%
					100.00%	100.04%

Source: Powerlink
Note 1: This is the top down weighting and reflects the likelihood that a combination of themes will eventuate.
Note 2: Red coloured (bold) weightings have increased, while green have decreased.

Table 4.13: Deterministic Network Capex for each Scenario ($m, 06/07)

Scenario	Adjusted Weighting	2007/08	2008/09	2009/10	2010/11	2011/12	Total[1]
1	7.88%	418	358	357	343	293	1768.50
2	1.10%	413	299	366	406	292	1776.16
3	6.78%	418	358	356	340	291	1763.10
4	1.10%	420	378	359	344	294	1794.68
5	3.79%	418	358	357	347	295	1775.43
6	0.50%	419	359	360	339	289	1766.14
7	2.29%	418	358	356	338	289	1758.46
8	0.50%	413	299	366	408	291	1776.76
9	10.87%	519	470	546	527	436	2497.86
10	1.50%	532	584	437	546	443	2542.47
11	10.07%	544	610	402	373	445	2374.88
12	1.50%	532	581	418	457	550	2538.60
13	5.88%	519	469	544	526	450	2508.18
14	0.90%	532	593	529	446	444	2544.53
15	5.58%	541	581	409	376	453	2359.48
16	0.80%	532	581	418	456	549	2536.27
17	6.68%	503	400	457	593	433	2385.40
18	0.80%	532	584	437	548	441	2543.06
19	4.89%	534	613	414	371	430	2362.69
20	0.70%	532	581	416	440	446	2414.31
21	3.79%	519	457	399	409	593	2377.11
22	0.50%	532	584	437	562	455	2570.03
23	2.89%	531	582	412	384	433	2342.45
24	0.50%	532	581	418	457	550	2538.86
25	3.39%	509	483	567	573	437	2569.23
26	0.40%	545	710	508	393	539	2695.66
27	2.89%	544	694	428	425	434	2524.14
28	0.40%	544	698	490	408	445	2585.58
29	1.69%	509	486	570	562	456	2583.66
30	0.30%	542	682	581	488	465	2757.93
31	1.60%	541	663	423	427	438	2491.69
32	0.30%	542	660	425	538	446	2610.91
33	1.99%	886	883	400	660	472	3299.91
34	0.30%	879	835	529	425	441	3109.64
35	1.99%	892	943	372	589	478	3272.89
36	0.30%	879	819	361	426	616	3101.81
37	1.10%	892	943	396	597	484	3311.69
38	0.20%	879	839	544	421	440	3124.21
39	1.20%	892	943	374	591	494	3294.36
40	0.20%	881	824	368	411	457	2940.87

Source: Powerlink
Note 1: Green colouring indicates expenditure less than Powerlink's proposed probabilistic weighted forecast of network capex of $2,345.52 million.

The probabilistic weighted capital expenditure identified by Powerlink in its Revenue Proposal is presented in Table 4.14, along with the maximum and minimum capex streams that represent the boundaries of the range of capex forecasts considered.

Table 4.14: Forecast Network Capex ($m, 06/07)

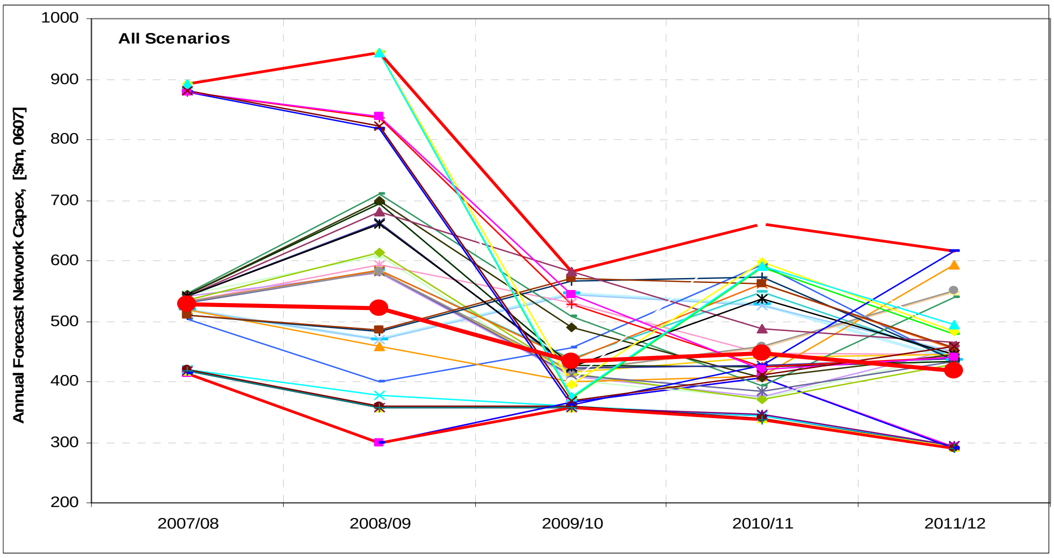
Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Overall weighted network capex	527.25	521.36	433.18	446.16	417.57	2,345.52
Max deterministic network capex	891.79	943.23	581.06	659.99	616.29	3,311.69
Min deterministic network capex	412.97	298.58	356.20	337.74	288.86	1,758.46

Source: Powerlink

It can be observed from Table 4.14 that the demand driven network capex varies considerably across each of the scenarios, and that in 2008/09 the maximum requirement is more than three times that of the minimum requirement.

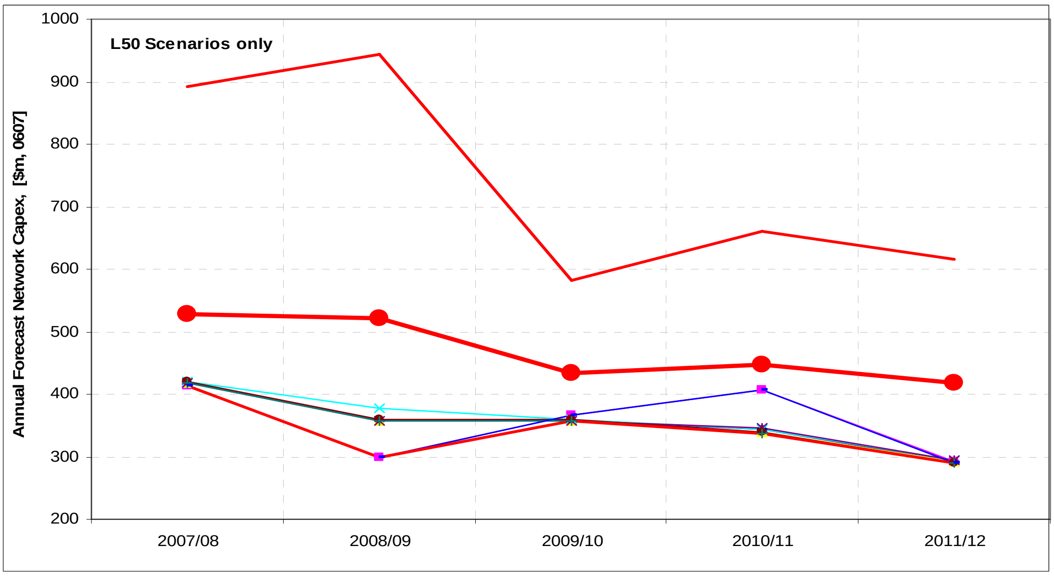
To better understand the drivers behind this variation, the data from Table 4.13 and Table 4.14 form the basis of the network related capital expenditure profiles shown in Figure 4-8 through to Figure 4-11. Each figure shows the individual capex streams from the limited number of scenarios relevant to a particular load growth theme. As a reference, each figure includes the maximum and minimum envelope of the deterministic capex for all scenarios using red traces, with the bold red trace with round markers showing the overall probabilistic weighted capex as used in the Revenue Proposal.

Figure 4-8: Network Related Capital Expenditure for all Scenarios



Source: PB Associates

Figure 4-9: Network Related Capital Expenditure for Low Growth Scenarios (50% PoE)

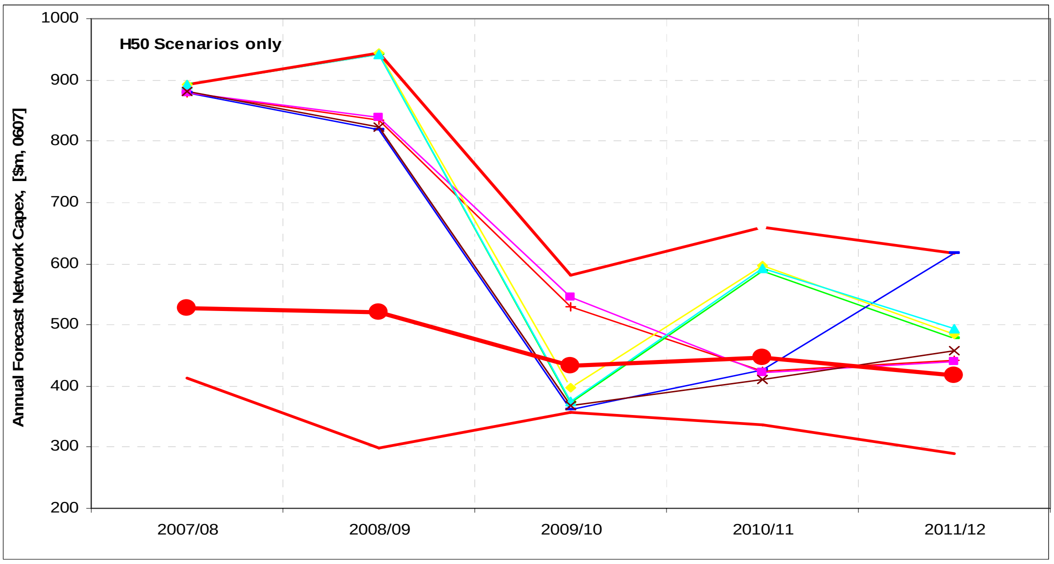


Source: PB Associates

Figure 4-10: Network Related Capital Expenditure for Medium Growth Scenarios (50% PoE)

Source: PB Associates

Figure 4-11: Network Related Capital Expenditure for High Growth Scenarios (50% PoE)



Source: PB Associates

Intuitively, it is expected that the accuracy of any forecast decreases as time progresses. The characteristics of Figure 4-8 through to Figure 4-11 are counter intuitive in the sense that the variations decrease, or improve with time. However, the large variation in capex in the first two years appears to be driven by the high load growth scenario in combination with the 'as incurred' approach. It reflects the advancement in demand driven augmentation projects that Powerlink would face under this scenario. The reduction over the remaining three years appears to be related to slowing demand growth in Queensland and the step-wise nature of transmission investment such that large network augmentations resolve constraints for many years.

Figure 4-8 through to Figure 4-11 indicate that while there is considerable variation in the annual network capex in any given year across all the scenarios, once the scenario capex is categorised into the load growth themes, there are very similar outcomes. This highlights the strong sensitivity of the forecast capex to demand growth. Table 4.15 presents this sensitivity in further detail. The same correlation, reflected in very low 95% confidence interval offsets[53] as shown in column 6 for the load growth themes, does not occur for any of the other theme sets (PNG gas, carbon tax, or QNI upgrades).

Table 4.15: Theme Set Based Forecast Network Capex ($m, 06/07)

Load Growth Theme	Sent-out 2007/08 Demand Forecast 2007/08 MW	Average annual growth, 5 years from 06/07 to 11/12 MW	Average annual growth rate, 5 years from 06/07 to 11/12 %	Average Deterministic Forecast Capex $m	95% Confidence Interval Offset $m	Adjusted Theme Set Weighting %
L50	9,026	215	2.4	1,772	8	23.9
M50	9,626	400	4.0	2,488	53	37.1
M10	9,998	415	4.0	2,442	64	20.7
M50++	9,626	600	5.9	2,602	60	11.0
H50	10,256	635	5.9	3,182	93	7.3

Source: PB Associates

53 The 95% confidence interval offsets represent the statistical upper and lower bounds within which the forecast capex for each of the eight individual scenarios within the load growth theme will occur with a high degree (95%) of accuracy. For each of the load growth themes the offset is less than 3% of the average, which is very low.

There is a significant difference in the average forecast capex for each of the three key load growth themes – low, medium and high and the average capex for the high load growth scenarios is, on average, 1.8 times the corresponding average capex for the low load growth scenarios. It is also important to note that the total probabilistic weighted capex sought by Powerlink of $2,346 million is lower than the average deterministic capex in each of the load growth themes except the low scenarios – this is driven by the relatively high adjusted weighting for the low theme compared with the high theme. It could be simplistically observed that if the high and low load growth scenarios were given the same weighting they would effectively cancel each other out. However, because the low load growth scenarios are given a higher weighting, the weighted average capex forecast is effectively "pulled down".

It is also interesting to note that the medium load growth 10% PoE theme results in forecast capex streams that are on average $46 million less than the average of those that would result from the medium load growth 50% PoE theme. This is due to the slight differences in generation planting across the various scenarios. Specifically, the conversion of Mt Stuart and Oakey power stations from open cycle to closed cycle systems, as well as the planting of additional Braemar generation under the 10% PoE scenario, defers the need for some transmission augmentation.

4.4.3.5 Probabilistic Planning Sensitivities

Sensitivity studies, referenced to the top-down weighting assessment, are shown in Table 4.16. They show the influence of modifying the weightings applied to each of the theme sets.

Table 4.16 shows that the sensitivity of changing the applicable weightings for any of the theme sets is relatively low. The greatest change (4.3%) is for the hypothetical scenario where it is assumed the weighting of each theme is the same.

The results also show that the adjustments made to the initial top down weightings by ROAM Consulting have resulted in a 2% reduction in Powerlink's capex requirement.

The introduction of the PNG theme acted to decrease the network related capex requirement, while modifying the likelihood of the PNG gas theme proceeding from 20% to 50% in accordance with updated analysis undertaken by ROAM Consulting in February 2006, resulted in a further reduction in the network related forecast capex of around 0.73%. The introduction of the increased QNI capacity theme had no material impact on the quantity of the forecast capex, while the use of the greenhouse tax theme increased the network capex requirement 0.53%.

Table 4.16: Network Related Forecast Capex Sensitivities ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total	Change[1] %
Top down weightings	541.89	543.68	431.64	452.13	424.90	**2,394.24**	0
Adjusted weightings	527.25	521.36	433.18	446.16	417.57	**2,345.52**	-2.03
Balanced weightings	579.02	593.06	432.74	456.72	435.69	**2,497.24**	4.30
Top down weightings and no M50++[54]	541.63	536.56	426.60	449.76	425.74	**2,380.28**	-0.58
Top down weightings and 80:20 No PNG:PNG split	537.37	515.50	451.80	482.68	424.37	**2,411.72**	0.73
Top down weightings and 100% No PNG	534.36	496.72	465.23	503.05	424.02	**2,423.37**	1.22
Top down weightings and 100% QNI	541.60	543.95	432.17	458.20	418.36	**2,394.28**	0.0
Top down weightings and 100% No tax	541.13	537.27	432.39	451.27	419.62	**2,381.67**	-0.53
Top down weightings and 100% No PNG and 100% QNI and 100% No tax	530.35	472.59	473.25	524.62	410.41	**2,411.22**	0.71

Source: PB Associates
Note 1: This is the percentage change in forecast capex when weightings have been changed relative to the top down weightings. Red coloured weightings indicate sensitivities where the forecast capex would decrease.

4.4.3.6 Conclusion on Themes, Scenarios and Generation planting,

Apart from the M50++ theme set, which is discussed in Section 4.7.2, we consider the themes and scenarios adopted by Powerlink for its probabilistic approach to be plausible and comprehensive in nature. They should capture most reasonable outlooks in Queensland over the review period. We also consider the weightings applied to all themes, including the load growth themes, to be reasonable and representative of their likelihood. We note that the forecast capex requirement is relatively insensitive to the non-load related themes.

We believe the approach adopted by ROAM Consulting to locate, size and then plant new generation of various technologies, as well as retire existing stations, has provided a reasonable basis for Powerlink's probabilistic based transmission planning, given information contained in NEMMCO's Statement of Opportunities and other information available in the public domain.

The probabilistic weighted network capex sought by Powerlink is slightly lower than that which would be realised under a deterministic medium load growth, 50% POE approach (that is, $2,346 million compared with $2,498 million for Scenario 9, respectively). In our view this provides further evidence that the approach appears to produce a reasonable outcome. The low sensitivity of change in the weighted capex for changes in theme set weighting also indicates the robustness of the outcome.

54 The impact of this sensitivity is determined by assuming the 10% allocated to the M50++ theme set is evenly shared across the M10 and the M50 themes.

4.4.4 Sensitivity of Capex to Economic Growth and Forecast Demand

Given the ex-ante approach to establishing capex requirements and with particular reference to the results in Table 4.15, there are a number of risks for Powerlink due to the high variance in the forecast capex across different economic growth scenarios. If the high load growth scenario is realised, Powerlink could suffer a windfall loss because it will be required to finance a number of capital projects in order to meet its mandated reliability standards. On the other hand, if the low growth scenario is realised, Powerlink could receive a windfall gain as it will not need to invest in its infrastructure as early as envisaged.

Appendix E of the Background Paper published with the ACCC's Decision on the Statement of Regulatory Principles (December 2004) includes a mechanism through which a TNSP may propose a pre-determined adjustment of its capital expenditure allowance for changes in demand by dynamically linking forecast capex to demand at the end of the regulatory period. This concept is suited to Queensland conditions and could minimise the potential windfall gain or risk of loss associated with a demand growth that is highly variable.

Powerlink considered such an approach as part of its Revenue Proposal preparation, and documented this, as presented in Appendix E of this report. It did not propose such a mechanism as it claims that the change from project capitalisations to 'as incurred' has complicated the ability to make such adjustments. In essence, Powerlink considers it appropriate to adjust capex allowances on forecasts of demand as opposed to the actual demand experienced. It also considers it a pre-requisite that the adjustments be made within the regulatory period, whereas the discussion in Appendix E of the Background Paper did not envisage within-period adjustments.

We believe that the probabilistic approach adopted by Powerlink attempts to capture the risk associated with sustained high or low load growth forecasts, and that it does so reasonably well through the appropriate selection of weightings for the defined projections. On this basis, and given Powerlink's views regarding the practical difficulties and complexities associated with an end-of-review adjustment mechanism linked to actual demand (rather than forecasts of it), we consider that the high or low demand scenarios that would be mitigated by dynamically linking forecast capex to actual demand are not likely to occur over the next regulatory period.

4.4.5 Assessment of Demand Driven Network Projects

We assessed in some detail a range of augmentation, connections and easement projects for this review, as shown in Table 4.17. Comprehensive discussion of each of the detailed reviews is included in Appendix H. It can be seen that the projects reviewed covered all of Powerlink's main asset categories and in total represented 32% of the value of the forecast capex requirement.

The project based forecast capex figures presented in Table 4.17 are determined from commissioning dates for the median of the earliest and latest dates envisaged in the scenarios where expenditure occurred within the regulatory period, and are also weighted based on the probability of the project proceeding, which is the aggregate probability of each scenario in which it is required.

The projects were generally selected to capture the cross-section of projects undertaken by Powerlink after giving due consideration to their costs, geographic location, need, timing, the type of constraint the projects addressed, and their probability of proceeding.

Table 4.17: Summary of Probability Weighted Demand Driven Capex Projects Reviewed ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Augmentations						
Strathmore to Ross 275 kV Double Circuit	-	3.37	33.67	1.62	-	38.66
Larcom Creek 275/132 kV Substation Establishment	10.50	31.57	0.46	-	-	42.53
Larapinta 275/110 kV Substation Establishment	-	9.16	39.71	6.23	-	55.10
275 kV Double Circuit Line into Larapinta	-	-	-	7.32	59.16	66.48
Molendinar 275/110 kV Transformer Augmentation	2.77	14.22	0.79	-	-	17.77
South Pine to Sandgate 275 kV Double Circuit Transmission Line Operating at 110 kV)	4.92	27.61	0.17	-	-	32.70
Establish Halys 275 kV substation and Calvale to Halys 2nd 275 kV Double Circuit 1st stage (single circuit strung)	4.76	47.56	2.28	0.00	0.00	54.60
Halys to Blackwall 500 kV Double Circuit Operating at 275 kV	-	-	3.22	32.14	1.54	36.91
Woolooga to North Coast 275 kV Double Circuit and 275/132 kV transformer	-	-	4.42	44.10	2.12	50.64
Moreton West 120 MVAr No.3	0.25	1.70	0.60	-	-	2.55
Rocklea 4th 110 kV 50 MVAr capacitor bank	0.20	1.63	0.06	-	-	1.89
Connections						
Bolingbroke QR Rail Supply	15.65	0.18	-	-	-	15.83
CQ No.1 132/33 kV Transformer	-	-	-	0.17	0.46	0.63
North Goonyella Upgrade	-	0.50	1.91	5.26	-	7.66
Easements						
South Coast 500 kV Double Circuit easement acquisition (TE)	-	-	1.79	1.77	0.34	3.90
South Coast 500 kV Double Circuit easement acquisition (compensation)	-	-	-	0.47	11.22	11.69
Logan to South Coast line rebuild easement clearance (TE)	-	1.56	1.20	0.21	-	2.97
Logan to South Coast line rebuild easement clearance (compensation)	-	-	0.35	5.73	-	6.08
Total Value of Reviewed Projects	**39.05**	**139.06**	**90.63**	**105.02**	**74.84**	**448.59**
Forecast Demand Driven Capex	408.26	387.4	196.23	207.45	196.47	1,395.81
Ratio of value of Projects Reviewed						32%

Source: PB Associates

In order to fully understand the projects under review, we had ongoing discussions with Powerlink staff. During these meetings our questions related to the type, location, timing and characteristics of the constraints experienced within the existing system – in particular the contingencies involved and the profile of the constraints over time and how they were growing. We sought advice on the sensitivity to generation and other market influences, and the way in which the constraints varied across the 40 scenarios under consideration. We also discussed Powerlink's consideration of operational and non-network alternatives, and how the identified network alternatives would resolve the constraints and for how long. We reviewed in detail the cost estimates for each project and its alternatives, and the NPV cash flow analysis Powerlink undertook in its least cost assessment for reliability augmentations. These discussions were supplemented by written questions and answers provided by Powerlink.

In general, our review confirmed the need for expenditure during the next regulatory period on the augmentation, connection and easement related projects. However, in a number of cases we believe that there are more efficient or more optimally timed options that will still allow Powerlink to achieve its reliability requirements. In particular:

- The forecast capex for the Strathmore-Ross line development appears out of proportion with the forecast demand growth and resulting constraint. We consider that a project that excluded the need to string the second circuit on the double circuit towers until after the end of the regulatory period was more economically efficient.

- In all scenarios assessed, Powerlink advanced the specific timing of the Molendinar transformer project to accommodate the timing under the high growth scenario. While the duration of the advancement was relatively short (7 months), it had a material impact on the annual expenditure profile of this project. It is recommended the timing be adjusted to correspond with that under the medium and low growth scenarios.

- The scope of work for the Larcom Creek substation development was excessive given the early stage of industry development in the area.

- The costs and the need for undergrounding of 110 kV lines were inappropriate when developing Larapinta substation.

- The timing of the transmission line development into Larapinta appeared marginal for the year identified and we consider that it could be deferred by one year without significantly changing Powerlink's risk profile.

- The South Pine – Sandgate project cost, timing and need as reviewed was reasonable.

- Powerlink identified and advised of changes in the optimal timing of a number of projects associated with the transfer capability from Central to Southern Queensland.

- Powerlink has not provided sufficient information to support the decision to establish 500 kV lines between Halys and Blackwall.

- There appears to be a lower cost option for dealing with the forecast constraint between Woolooga and Gympie.

- Reasonable and efficient levels of reactive compensation in the form of shunt capacitor banks are programmed.

- Customer related connection projects were generally reasonable and efficient, except for some required under the high growth scenario.

- Easement acquisition projects were generally reasonable but could be staggered more efficiently in the final years of the review period.

Our specific project reviews indicate that Powerlink's demand driven capex forecast is overstated - by approximately $147 million across the sample of projects (refer to Appendix H, and our table of recommendations in Section 4.11)[55]. The key changes related to projects of greater scope than necessary to meet the constraint and inappropriate project timing. On the basis that the projects we selected for review were a good representation of the entire probabilistic based forecast program, we recommend a further 4% reduction on the balance of Powerlink's demand driven network capex, in accordance with Table 4.18, in order to remove what we consider to be a systematically high capex forecast. Our recommendation of a 4% reduction, which equates to around $38 million, or one large project, is based on a conservative estimate of the extent of overstatement in Powerlink's revenue proposal given the outcome of our detailed review.

Table 4.18: High Level Demand Driven Capex Review ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Total Value of Reviewed Projects	39.05	139.06	90.63	105.02	74.84	448.59
Forecast Demand Driven Capex	408.26	387.4	196.23	207.45	196.47	1,395.81
Balance of Forecast Demand Driven Capex	369.21	248.34	105.6	102.43	121.63	947.22
Recommended Proposal	354.44	238.41	101.38	98.33	116.76	909.33
Change	-14.77	-9.93	-4.22	-4.10	-4.87	-37.89

Source: PB Associates

4.4.5.1 General Conclusions on Demand-Driven Project Reviews

We have reviewed Powerlink's proposed forecast of its demand driven network capex on augmentation, connections and easement projects over the next regulatory period. Our main conclusions are listed below.

- Powerlink has undertaken a systematic and rigorous review of a complex network using advanced planning techniques to capture all possible capex in the review period.

- Powerlink has not justified any augmentation projects through the market benefit limb of the regulatory test. However it has used market benefits based on the value associated with reduced transmission losses to differentiate between some project alternatives.

- Powerlink initiated a review of the CQ-SQ transfer requirements and associated projects, which resulted in a reduction in the forecast capex of $41.3 million. While our review of this adjustment has been at a high level, and there has been limited opportunity to analyse the modified project program in detail, we have taken Powerlink's advice on the reduction in forecast capex at face value given the detailed analysis undertaken by Powerlink.

- While Powerlink's grid planning analysis contains a comparison of options in nearly all cases, Powerlink appears to have assessed and documented relatively few alternatives, in particular for transmission line projects. Options considering

55 In estimating revised project costs we have generally adjusted the project configuration and applied Powerlink's BPOs to the adjusted configuration.

the use of lower capacity or single circuit designs, or projects related to improving the capability of existing assets were rare and Powerlink adopted an approach of building high capacity double circuit lines for a large number of its projects. Powerlink provided a number of reasonable arguments as to why less costly projects were less beneficial in a high demand growth environment, such as improved economies because the requirement for the second circuit would occur after only a short period of time, the potential for economic benefits through increased loss reduction, or minimising the social and environmental impacts of piecemeal construction activities along easements. Nevertheless, we consider it would be prudent for Powerlink to consider some of these options in a more detailed and transparent manner on a project by project basis.

- There was limited information presented on the economic analysis undertaken by Powerlink for a number of projects. In some cases this was attributed to the distant planning horizon covered by the analysis and the limited and more speculative information associated with projects required towards the end of the review period. In other cases it was attributed to the sheer volume of analysis required as part of the extensive probabilistic planning approach. We also note that when the NPV analysis was undertaken, the interest rate used was relatively low (7%), which disadvantaged projects that depended on deferring others in time. While Powerlink states that this discount rate (real pre-tax) is similar to that which regulated transmission businesses receive for their investments, we consider sensitivity studies could have been presented consistent with the approach taken in Powerlink's Application Notices, which typically use a discount rate of 8%, 10% and 12% as required under the Regulatory Test. This would have been particularly appropriate where a number of project alternatives had similar NPV's.

- Powerlink presented limited information in its Grid Plan on the overloads that were forecast and how they would grow over time. However this information was made readily available to us upon request. The inclusion of such data in the Grid Plan would support Powerlink's decision process, in particular the basis for its shortlisted network options.

- In some instances, network augmentation tends to take precedence over other non-network options that may be more efficient. There appeared to be some opportunities for Powerlink to use discretion and negotiate with connected parties or implement DSM for constraints that were triggered by a marginal overload in one year but which were then reduced in following years due to generator planting or some other factor.

- There also appeared to be some opportunities for Powerlink to adopt a more innovative approach to its planning by extending its investigations into the use of control schemes to temporarily defer some network augmentation planned to cover for extended and forced generating plant outages under its N-G-1 planning criteria.

- Powerlink appeared to take a number of opportunities to incorporate designs into its projects to meet anticipated longer term requirements. Examples included the proposed construction of switch bays to allow for future lines or capacitors, or the extension of transmission lines to areas not yet constrained. Whilst this shows some strategic initiative, there were occasions identified were this approach was considered inefficient and project costs were recommended to be reduced.

- Powerlink and the DNSPs are undertaking effective and practical joint planning that considers a large number of options and anticipated projects, and the NPV analysis is reasonable and thorough. However, there were 15 projects (with an aggregate unweighted capital cost estimate of over $168 million), out of a total of over 400 projects, for which no suitable documentation was prepared in time for inclusion in the publication of Powerlink's 2005 Grid Plan. Powerlink advised that information would be made available on these projects as required and was able to provide detailed evidence and analysis to support its proposed capex when the information was requested.

- Powerlink has undertaken a rigorous process to develop a reasonable and efficient program of reactive compensation projects comprising shunt capacitor banks and Static VAr Compensators.

- Powerlink has developed plans in the SEQ region, in particular the Gold Coast/Tweed Heads zone, assuming DirectLink flows will be from north to south until 2012/13. The AER recently calculated the regulated asset value for DirectLink based on the assumption that it would flow south and defer grid augmentations in northern NSW. We have not verified this analysis or the assumptions on which it was based.

- The two proposed 275 kV underground cables that we have reviewed as part of our detailed project investigations appear to be reasonable and prudent given their locations.

4.5 NON-DEMAND DRIVEN NETWORK CAPEX

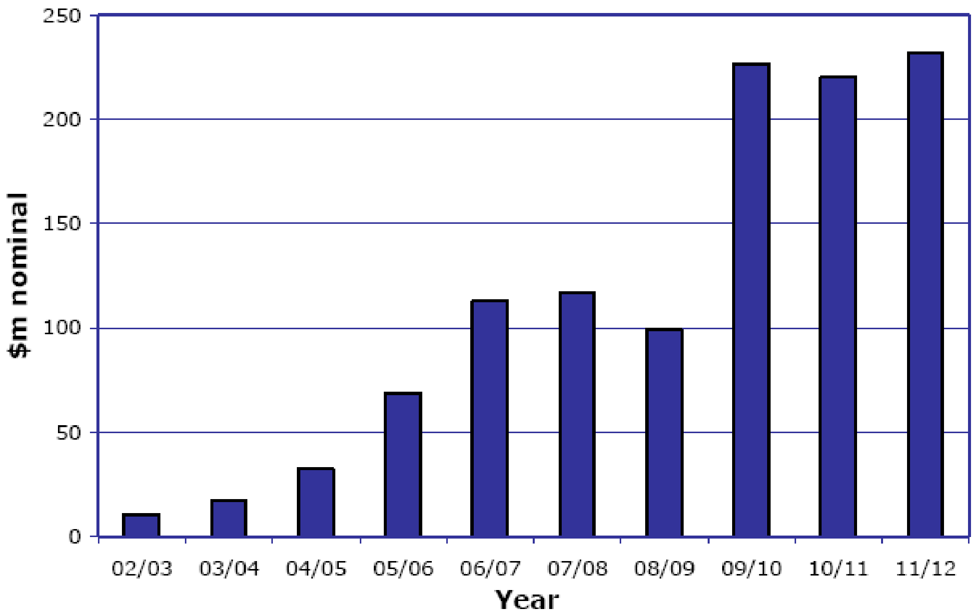
4.5.1 Replacements

4.5.1.1 General

Powerlink has forecast expenditure of $812.8 million over the next regulatory period on the replacement of its existing assets. This represents 33% of its forecast capital expenditure requirements over the period. It is also substantially higher than the $164.4 million of asset replacement expenditure that Powerlink estimates it will capitalise over the current 2002-07 regulatory period. The forecast expenditure requirement has been prepared on the basis of a comprehensive Non-Load Driven Network Development Plan.

As is shown in Figure 4-12, Powerlink's actual and forecast capital expenditure has increased by a factor of three between 2004/05 and 2006/07 and a further doubling is forecast between 2008/09 and 2009/10.

Figure 4-12: Historic and Forecast Expenditure on Replacements



Source: Powerlink Revenue Proposal, p70

According to Powerlink's Revenue Proposal, this substantial increase in expenditure is required as a result of a significant investment in new assets 40 to 50 years ago and these assets are now reaching the end of their life. It considers that transmission lines normally have an economic life of 50 years, substation plant and transformers 40 years and secondary systems 15 years.

These asset lives are lower than used by some other TNSPs. For example, the New Zealand Optimised Deprival Valuation Handbook[56] and the draft New South Wales Treasury Valuation Guidelines[57] specify asset lives of 55 years and 60 years respectively for lattice steel tower transmission lines. The New Zealand Handbook specifies a standard life 55 years for large power transformers and 45 years for other outdoor substation equipment while the New South Wales Treasury Guidelines specifies standard lives of 45 years for all substation equipment.

One driver of earlier replacement may be the climatic conditions that the equipment has to endure over its lifespan. For example corrosion of transmission towers can be accelerated if high humidity is experienced, which will bring forward the replacement date. Importantly, Powerlink does not rely solely on age, but uses age as a trigger to carrying out a detailed condition assessment. Assets are only replaced on the basis of their condition.

Powerlink classifies protection and control secondary systems with a standard life of 15 years. In contrast the New Zealand Handbook specifies a standard life of 40 years while the New South Wales Guidelines values this equipment as part of the primary asset. Like Powerlink, the New Zealand Handbook specifies a standard life of 15 years for SCADA and communications equipment while the New South Wales Guidelines specifies only 10 years. While the lives of protection and control equipment in the New Zealand Handbook are appropriate for electromechanical and hard wired electronic systems, they could arguably be less appropriate to the computerised programmable electronic relays now available. Nevertheless modern relays are designed to fit into modular panels. These panels and the interconnecting cabling used to connect to the primary equipment still

56 New Zealand Commerce Commission, August 2004, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses*.

57 New South Wales Treasury, May 2003, *Valuation of Electricity Network Assets: A Policy Guideline for NSW DNSPs (Draft)*.

make up a significant proportion of the cost of these systems and these components have a life well in excess of 15 years.

In order to better understand the need for asset replacement it is useful to review the history of the development of Powerlink's transmission network. This is discussed below.

Prior to the 1970s there was no interconnected transmission network in Queensland. North Queensland, Central Queensland, Wide Bay Burnett and South Eastern Queensland each had their own individual power systems, which were completely isolated from one another. Each system was initially developed with power stations close to the major towns and as a result transmission capability, at the voltages now operated by Powerlink, was not required.

North Queensland was the first region to require significant high voltage transmission as a result of the development of the 72 MW Kareeya hydroelectric power station in the mid-1950s to supply electricity to Cairns and Townsville. This saw the construction of the Kareeya-Innisfail-Cairns and Kareeya-Tully-Townsville lines that today are the oldest lines on the Powerlink network.

This was followed in South East Queensland in the mid 1960s with the development of a 110 kV network to support the Tennyson B and Swanbank A power stations. At around the same time a 132 kV network was also developed in Central Queensland when the Callide A power station was developed to supply Rockhampton, Gladstone and the new central Queensland coal mines.

The first 275 kV lines were not constructed until between 1969 and 1971 to supply electricity generated by the Swanbank B power station to South Pine, north of Brisbane, Belmont, to the south of Brisbane, and a little later to Mudgeeraba on the Gold Coast. In 1972, the first 275 kV interconnector between two of the isolated systems was constructed between Gladstone and South Pine to allow electricity generated at Gladstone power station to supply Brisbane. This was followed by a second circuit in the early 1980s to coincide with the completion of the final two units at Gladstone. The 275 kV network was extended to Townsville between 1977 and 1984 and more recently as far north as Cairns.

When the electricity supply industry in Queensland was restructured in the 1990s, many of the older radial 110 kV and 132 KV lines were transferred to Energex and Ergon Energy. Lines that formed part of the interconnected transmission network were transferred to Powerlink.

Hence, while most TNSPs will have some much older assets, the oldest assets on the Powerlink network are the 132 kV lines between Townsville and Cairns, which are only now reaching the end of their expected life and which are scheduled for replacement over the next regulatory period. Until now there has therefore been little need to embark on an aggressive program of transmission line replacement, although the replacement of the 132 kV lines in Far North Queensland has been under discussion for some years and the replacement of the lines between Yabulu and Tully was forecast at the time of the last revenue reset in 2001. This project is discussed further in Appendix I. During the next regulatory period Powerlink is also planning a number of life extension projects on 132 kV and 110 kV lines constructed in the 1960s in order to prevent these lines deteriorating to the extent that full replacement will be required. It is also planning to replace earth wires on the 275 kV South Pine-Townsville lines, which are suffering from corrosion and, more particularly, from vibration damage thought to be a result of over-tensioning during construction.

Most of the 132 kV substations in North Queensland have been rebuilt or refurbished over the last ten years but the early 132 kV substations in Central and South East Queensland are now reaching an age where replacement or refurbishment is becoming necessary. These substations are larger than those replaced to date and more numerous and thus require a commensurate increase in the replacement capex budget.

Secondary systems replacement includes replacement or upgrade of protection relays, control devices, ancillary service and protection signalling equipment. It can also include the incorporation of new technologies, such as a change from PLC to dedicated wire or fibre optic signalling. As noted above Powerlink assigns a life of 15 years to secondary systems based on the expected life of equipment containing solid state electronic and computer equipment. However the cabling and panel infrastructure that supports the electronic components, which is often constructed in a modular form to permit ready replacement or upgrade of the electronic components, comprises a significant proportion of the cost of such systems and can have a much longer economic life.

Table 4.19 compares the forecast capitalisation of replacement capex projects for the next regulatory period, broken down by asset type, with the anticipated replacement project capitalisations for similar assets during the final five years of the current regulatory period. This clearly demonstrates the substantial increase in transmission line replacement capex, which represents over 40% of the total forecast replacement capex over the next regulatory period. It can also be seen that the relative expenditure for each asset class is generally consistent with the high level overview presented above.

Table 4.19: Comparison of Forecast Expenditure with Current Expenditure by Asset Type ($m, nominal)

Item	2002-07	2007-12	Increase
Lines	17.44	343.67	1,871%
Substations	99.16	324.15	227%
Secondary Systems	32.42	154.75	377%
Telecommunications	3.47	6.18	78%
Total	**152.49**	**828.75**	**443%**

Source: Powerlink
Note: Costs are presented on a capitalisation rather than expenditure basis and represent the costs of projects Powerlink expects to be completed during the two five-year periods.

4.5.1.2 *Development of Replacement Capex Forecast*

The replacement capex forecast contained in Powerlink's Revenue Proposal was developed in accordance with its Asset Replacement Policy issued in July 2005. While the written policy appears to have been prepared to provide some structure to the process of forecasting replacement capex requirements for the Revenue Proposal, there is evidence to indicate that it largely documents procedures that were already being implemented[58].

The policy identifies four triggers for asset replacement as shown in Table 4.20.

58 Powerlink stated that the policy is actually an update of an earlier document. However this is not reflected by the document control.

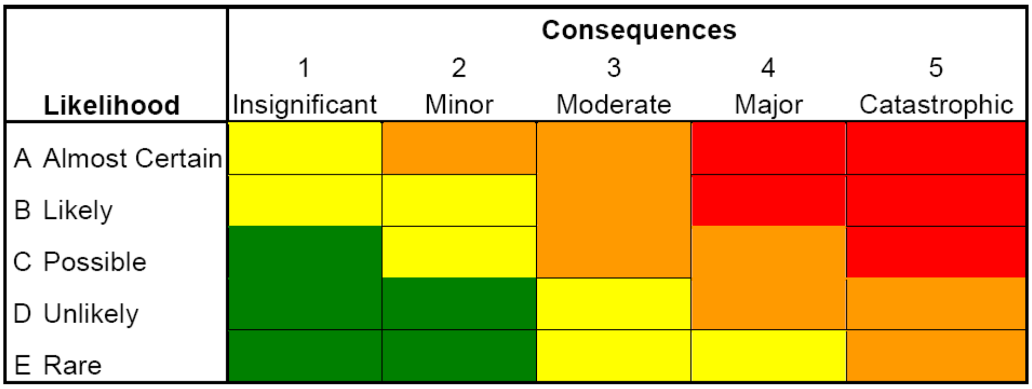
Table 4.20: Asset Replacement Triggers

Trigger	Comment
Age	The policy clearly states that age is a trigger for a condition assessment and not, in itself, a justification for replacing an asset. This is consistent with good electricity industry practice. For primary assets, a condition assessment is indicated when an asset's age reaches 80% of its expected economic life.
Capacity	Capacity reflects the rating of an asset and whether it is adequate for the loading now required. Many asset replacements are triggered by inadequate fault rating. . Powerlink treats the replacement of an existing asset as an augmentation only if it increases the capability of the network to transfer active energy, citing the definition of augmentation in the NER[59]. Hence an increase in the fault clearing capacity of a plant item is not considered an augmentation, but is considered replacement.
Capability	Capability is expressed as the ability of the asset to continue to perform at the required level. An asset's capability will be reduced if it is in poor condition, but it could also be reduced if parts or manufacturer's support are no longer available or if the equipment is of an age where there is no longer technical support within Powerlink.
Compliance	This covers regulatory or legal issues that may impact on a decision to replace an asset. This may involve the application of environmental legislation, the NER, the Electrical Safety Act or relevant workplace health and safety legislation.

Within this framework the Asset Replacement Policy requires a risk analysis to be undertaken in accordance with AS/NZS 4360:2004. This approach assesses the potential consequences if an asset is not replaced using a two dimensional framework. One dimension is the likelihood of the event occurring which is assessed on a scale of A-E, with A being "almost certain" and E being "rare". The second dimension is the consequences of the event, which is assessed on a scale of 1-5 with 1 being "insignificant" and 5 being "catastrophic". Asset replacements are prioritised on the basis of this risk profile. Assets with a risk score of A5 have a high priority for replacement whereas there would be little reason to replace an asset with a risk score of E1. Of course, most assets considered for replacement have a risk score between these two extremes.

This approach is most useful in situations where the budget is constrained. In this situation different risks can be assessed relative to one another and the location of the replacement threshold between the two risk score extremes can be determined by the available funds.

Figure 4-13: Powerlink's two-dimensional risk assessment framework



Source: Powerlink

59 In the NER, network augmentation is defined as works to enlarge a *network* or to increase the capability of a *network* to transmit or distribute *active energy.* This appears to preclude fault rating upgrades from being treated as augmentations.

However availability of funding was not a tight constraint on Powerlink in developing its Revenue Proposal and the policy does not specify where on the matrix the "unacceptable risk" threshold should be. We understand that in preparing its Revenue Proposal Powerlink has generally proposed the replacement of assets where the risk of doing nothing was assessed to be in the red or orange areas of the above matrix, in which case the risk was assessed as "very high" or "high".

While we think the application of the risk matrix has merit, and while we acknowledge that Powerlink has prepared guidelines to assist with the consistent assignment of risk scores, we nevertheless consider that the process of risk determination is still inherently subjective. Furthermore, our reviews of proposed replacement projects provided little evidence to show that Powerlink had seriously considered other measures, apart from asset replacement, as a strategy for mitigating identified risks.

4.5.1.3 Project Assessment

We assessed in some detail a range of asset replacement projects for this review, as shown in Table 4.21. A discussion on each of the projects reviewed is included in Appendix I. It can be seen that the projects reviewed covered all of Powerlink's main asset categories and in total represented 45% of the forecast replacement capex requirement. Where a large project comprised a number of smaller components with each component identified as a separate project, we reviewed the need for all projects since we felt that this would provide a more informed basis on which to assess the need for the work.

In general, we found that there is a need for replacement work during the next regulatory period on all the projects reviewed. However, in many cases the project scope on which the forecast cost was based was greater than the level of replacement likely to be required.

In particular:

- The forecast cost of the Yabulu-Edmonton 132 kV line upgrade was substantially increased by the decision to use 275 kV towers and to construct one circuit at 275 kV in order to provide for a third 275 kV supply to Cairns. While the major driver for implementing this project at this time was to replace the existing 132 kV lines, in our view this project, as scoped, should have been classed as a major transmission system augmentation and subject to the NER regulatory test and consultation requirements. We accept that it is probable that the regulatory test and consultation process would have confirmed the option selected by Powerlink, but nevertheless consider that the alternative of only stringing the 132 kV circuit at this time should have been more seriously considered.

- The forecast cost of the Swanbank 275 kV substation rebuild provides for the rebuilding of the facilities used to connect the Swanbank B power station. However there is a strong possibility that Swanbank B power station will be decommissioned during or soon after the end of the next regulatory period in which case the rebuild of these bays will not be required. ROAM Consulting's generation development scenarios identified Swanbank B power station to be retired within the next regulatory period in all 40 scenarios.

- The forecast cost of the Tarong secondary systems replacement provides for a full rebuild and replacement of all secondary systems on the site. In our view the condition assessment does not support such a major project. While we accept that project implementation is constrained by the need to keep primary plant operational, much of the equipment to be replaced has only recently been installed as a result of operational refurbishment projects and could be reused.

Our project reviews indicate that Powerlink's replacement cost forecast should be considered, at best, an upper bound to the range of possible replacement cost. Unlike augmentation projects, Powerlink has a significant amount of discretion over the timing of asset replacements. We agree that the current level of asset replacement expenditure is not sustainable going forward and that a significant increase is justified. Nevertheless, we consider that a prudent operator working in a competitive environment would be able to continue its operations on a significantly lower replacement cost budget than proposed by Powerlink for the next regulatory period while at the same time avoiding any material reduction in the level of service provided to customers.

Furthermore, as Powerlink acknowledges in its proposal, the level of capex proposed for the next regulatory period will stretch available resources and will only be implemented with difficulty. Should the volume of capex that Powerlink is able to deliver be limited by resource constraints, then replacement, rather than augmentation, projects are most likely to be deferred because Powerlink has more discretion over their timing. Overall, we think that it is highly likely that some of the significant amount of replacement capex programmed for the last three years of the next regulatory period will need to be deferred to the 2012-17 regulatory period. As an example of the type of delay that can occur, the replacement of the Yabulu-Ingham-Cardwell-Tully lines were provided for in the 2001 revenue cap decision but did not proceed due to delays in obtaining the required approval from the Commonwealth Environment Minister.

While our detailed project reviews indicate that Powerlink's proposed capex on asset replacement is high, from the information available we were not able to form a view on the amount by which the replacement forecast should be reduced. We therefore believe that a top-down analysis is a better approach to addressing this issue and this is discussed in the following section.

Table 4.21: Summary of Replacement Capex Projects Reviewed ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Transmission Line Replacements						
Yabulu-Ingham		5.59	41.64	27.03		74.26
Innisfail-Edmonton		6.82	50.41	0.58		57.81
Cardwell-Tully				10.94	35.82	46.76
Ingham-Cardwell			3.31	31.82	6.62	41.75
Kareeya-Innisfail[1]	19.14	18.60				37.74
Wurdong – South Pine Earth Wire Replacement	1.41	6.66	11.58	4.69	15.39	39.74
Substation Primary Plant Replacements						
Swanbank B Rebuild	-	-	2.43	9.40	25.97	37.80
Substation Secondary Systems Replacement						
Tarong Secondary Systems Replacement	-	-	4.74	20.23	1.56	26.53
Communications Systems Replacement						
Eagle Heights to Mudgeeraba Microwave Radio Replacement	0.22	0.17				0.40
Virginia to Mt Gravatt Microwave Radio Replacement			0.26	0.20		0.46
Wilkes Knob to Mt Glorious Microwave Radio Replacement				0.51	0.05	0.56
Metropolitan Communications Systems Replacement – Stage 2				0.20	0.15	0.35
Total Value of Reviewed Projects	**20.77**	**37.84**	**114.37**	**105.60**	**85.56**	**364.16**
Forecast Replacement Capex	113.72	93.58	208.07	196.39	201.05	812.80
Ratio of value of Projects Reviewed						45%

Source: PB Associates
Note 1: In addition $9.91 million is budgeted for this project for the two year period 2005-7.

4.5.1.4 Assessment of Asset Replacement Capex Forecast

We have reviewed Powerlink's proposed forecast of its asset replacement requirements over the next regulatory period and undertaken a more detailed assessment of a number of replacement projects proposed for implementation over the period. Overall we consider that:

- The rationale that Powerlink uses to justify the substantial increase in asset replacement requirements is well founded and, going forward, asset replacement expenditures need to be increased.

- Powerlink's standard asset lives are lower than we would expect and are generally lower than the standard asset lives used in other jurisdictions. However this should not impact the level of asset replacement required since Powerlink's asset management systems clearly specify that asset age should only be used as a trigger for a more in-depth condition assessment.

- Powerlink has documented procedures for identifying and prioritising asset replacement requirements. While these procedures are consistent with good electricity industry practice, most appear to have been prepared primarily to provide some structure to the process of forecasting replacement capex requirements for the Revenue Proposal.

- A number of our detailed project reviews have indicated that the project scope used as the basis for estimating the cost of the project replacement costs was greater than justified by the condition assessments. We believe that the forecast should therefore be considered, at best, an upper bound of a range of possible replacement cost forecasts and that an operator in a more competitive environment would be able to rely on a significantly lower replacement budget without any material impact on the level of service.

- Powerlink has a significant level of discretion over the timing of replacement cost projects. Powerlink has acknowledged that its forecast capex will be difficult to achieve given the limited availability of implementation resources. We think it highly likely that much of the replacement work programmed for 2009/10-2011/12 will need to be deferred to the 2012-17 regulatory period.

A useful rule of thumb for determining an appropriate level of asset replacement is that expenditure on asset replacement should reflect the depreciation cost since, if the age profile of an asset is flat, this will ensure that there is no increase in the average age of the asset base. Powerlink may have applied this rule of thumb to test whether its proposed asset replacement forecast is realistic – its forecast asset replacement for the next regulatory period of $812.8 million is only 7% lower than its forecast depreciation requirement of $875.6 million[60]. However, a significant component of this depreciation will include depreciation on assets installed over the next regulatory period, as can be seen from the fact that the depreciation requirement is forecast to increase by 25% over the period.

An age profile of Powerlink's asset base is provided in Figure 2.6 of its Revenue Proposal. This shows that until about 1998 the asset age profile is relatively flat but the development of the network has accelerated since then. A closer analysis of the profile indicates that approximately 35% of the current asset base has been installed over the ten year period 1996-2005. Assuming the standard asset lives used by Powerlink, none of these newer assets will need replacement before the end of the next regulatory period. Hence assets that will be replaced over the next regulatory period will be selected from the remaining 65% of the asset base, since these assets will be over 15 years old by the end of the period.

Powerlink assumes a 50 year life for transmission lines, a 40 year life for substations and a 15 year life for secondary systems. Based on the relative proportions in a typical transmission system, we think that a conservative assumption for the capital weighted average life of the RAB is 35 years. Powerlink's estimated depreciation for 2007/08 is $154.12 million, which would indicate an undepreciated opening RAB of $5.4 billion of which $3.51 billion would be more than 15 years old at the end of the current regulatory period.

We believe that it would not be unreasonable for Powerlink to be replacing assets at this point in time at a rate that would ensure that this $3.51 billion portion of the asset base was renewed over a 35 year period. This would indicate a requirement of $100 million a year or $500 million over the regulatory period. However, as noted in the project reviews, there is an augmentation element in many of Powerlink's replacement projects. Furthermore, there is an additional cost involved in replacing assets because of the need to maintain supply and work around existing live infrastructure. This indicates that a replacement premium and an augmentation premium should be added to this base cost. We estimate that the replacement premium is likely to be around 20%. The appropriate value for the augmentation premium is more difficult to estimate since it is dependent on the way that Powerlink categorises its projects. Nevertheless, we think a 20% augmentation premium would also be reasonable. On this basis we consider that an asset replacement requirement of $140 million per year on average, or $700 million over the regulatory period, would be reasonable, in accordance with the proposed asset replacement capex profile shown in Table 4.22.

60 Powerlink Revenue Proposal, Table 8.1.

Table 4.22: High Level Review of Proposed Replacement Capex Profile ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Aggregate Powerlink proposal	113.7	93.6	208.1	196.4	201.1	812.8
Aggregate Recommended Proposal	113.7	93.6	155.0	165.0	175.0	702.3
Change	0.0	0.0	-53.1	-31.4	-26.1	-110.5

Source: PB Associates

The quantity and timing of cash flow changes has been established to allow Powerlink to achieve its original replacement objectives over the initial years of the regulatory period.

We consider that this provision should be sufficient to cover all asset replacements and major refurbishments, including the $48.36 million capital related operational refurbishments that we recommended should be treated as capex in Section 5.5.8. If this capital refurbishment is to be treated as a separate line item then the recommended asset replacement capex provision in Table 4.22 should be reduced accordingly.

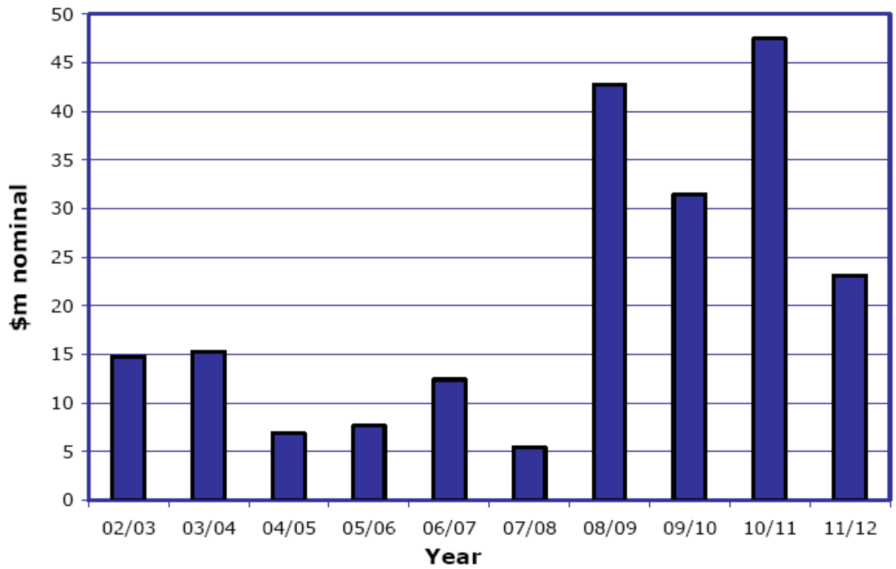
Given the high level analysis that is relied on to reach this conclusion, and the fact that the amount we have suggested is significantly less than requested in Powerlink's Revenue Proposal, it is appropriate to consider the consequences for Powerlink if we have got this wrong. The $140 million per year is well in excess of the average replacement capex over the current regulatory period and is more than sufficient to cover Powerlink's proposed requirement for the first two years of the next regulatory period. Any shortfall will not be apparent until the final three years. As we noted above, the timing of much of this expenditure is discretionary and we consider it highly likely that much of this proposed capex will be deferred to the 2012-17 regulatory period for other reasons. However, if Powerlink is able to show at the 2012 regulatory reset that the amount provided has been insufficient to meet its prudent asset replacement requirements, then the AER could increase the provision in the early years of the 2012/17 regulatory period to allow Powerlink to catch up on any backlog.

4.5.2 Security/Compliance and Other

4.5.2.1 General

Powerlink has forecast expenditure of $136.9 million over the 2007-12 regulatory period related to security/compliance and other non-demand driven network obligations. While this is only approximately 5.6% of all forecast capex, the amount is considerably higher than expenditure in these categories during the current regulatory period, as shown in Figure 4-4. The program is comprised of five individual security/compliance projects which make up 75% of the capex, and 13 other projects.

Figure 4-14: Historic and Forecast Expenditure on Security/Compliance and other Non-load driven network investment



Source: Powerlink Revenue Proposal, p71

According to Powerlink's Revenue Proposal and its Non-Load-Driven Network Development Plan, these project types undergo the same project scoping, risk profiling, option identification and estimating processes as the replacement program projects.

The increase in expenditure is predominantly associated with an identified program of investment required to satisfy the obligations contained within new *National Guidelines for Protecting Critical Infrastructure from Terrorism.*[61] This is consistent with Powerlink's proposal in that the security/compliance component makes up 75% of the combined security/compliance and other capex.

Compliance projects include an ongoing program of work to meet Australian Standards and the NER, and "other" non-load-driven projects are associated with telecommunication network upgrades, and protection system and switching configuration changes to maintain power system security.

4.5.2.2 Project Assessment

In combination with our high level review of the security/compliance and "other" non-demand-driven network capex program, we assessed two projects in detail comprising 71% of the forecast amount, as shown in Table 4.23.

[61] Refer Australian Government website, www.nationalsecurity.gov.au

Table 4.23: Summary of Security/Compliance and Other Capex Projects Reviewed ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Substation Access Security	-	6.48	17.31	6.76	18.09	48.64
Transmission Line Structure Security Upgrade	2.51	20.73	3.10	21.69	0.49	48.53
Total Value of Reviewed Projects	**2.51**	**27.21**	**20.41**	**28.45**	**18.58**	**97.17**
Forecast Security/Compliance and Other Capex	5.27	40.38	28.89	42.32	20.05	136.91
Ratio of value of Projects Reviewed						71%

Source: PB Associates

Our assessment of the Substation Security Upgrade project provided an understanding of the risk based approach adopted by Powerlink in respect of site access to approximately 100 switchyards and substations. The scope of work includes a detailed risk assessment of each site, categorisation of sites into those that require basic, medium and high security upgrades/requirements and implementation of appropriate passive and active security measures in accordance with the National Guideline for the Prevention of Unauthorised Access to Electricity Infrastructure. The average cost per substation was around $400,000, but in some cases this increased to over $1.1 million. We are satisfied that there was a genuine need for this project, that Powerlink has undertaken a reasonable approach in considering other alternatives, and that its final classification of substation sites is such that the costs are efficient while ensuring identified risks have been mitigated. We do note however, that Powerlink does not intend to initiate this project until the 2008/09 financial year. If anything, given the importance of the project, we would expect expenditure to have been advanced for this work. On this basis, we recommend that some of Powerlink's proposed scope be advanced and that the capex be slightly redistributed over the review period, as described in Table 4.24.

Table 4.24: Adjustment to Substation Access Security Upgrade Project ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink Proposal	-	6.48	17.31	6.76	18.09	48.64
Recommended Proposal	4	10	14	8	12.64	48.64
Change	4	3.52	-3.31	1.24	-5.45	0

Source: PB Associates

Our assessment of the Transmission Line Structure Security Upgrade project provided an understanding of the history, the need and the risk based approach Powerlink undertook to identify works to minimise the access to and maximise the security of its extensive transmission line infrastructure. We are satisfied of the need for the proposed works, which involves prioritising towers based on their location and criticality, and visiting each one to implement specific security measures. However, given the wide-scale nature of Powerlink's project, by prioritising its works we believe it would mitigate the majority of its envisaged risks once 50% of the project was completed given that many towers located in remote locations would be far less exposed to security related breaches and that the impact of any security breach would be limited. As with some replacement projects, we believe that Powerlink will have more discretion to defer the timing of some of this work should its overall ability to deliver its capex program become an issue. On this basis, we recommend that some of Powerlink's proposed scope be carried into the next regulatory period and that the capex be slightly redistributed over the review period, as described in Table 4.25.

Table 4.25: Adjustment to Transmission Line Structure Security Upgrade Project ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink Proposal	2.51	20.73	3.1	21.69	0.49	48.53
Recommended Proposal	2.51	15	8	8	2	35.51
Change	0	-5.73	4.90	-13.69	1.51	-13.02

Source: PB Associates

4.5.2.3 *Conclusions on Security/Compliance and Other Forecasts*

We have reviewed the detailed internal policies and plans Powerlink has established for both substation and transmission line security requirements and undertaken a high level review of Powerlink's other non-demand driven network capex projects.

Overall, we consider that the need for Powerlink's investment is genuine, and that the basis for the considerable increase towards the end of the regulatory period is generally valid. A large proportion of this capex is in accordance with newly developed national guidelines on the security of critical infrastructure. We also consider Powerlink has taken reasonable steps to identify a number of alternative developments and that its cost estimates appear reasonable and efficient. However, in accordance with Table 4.24 and Table 4.25, we consider that the timing of some of the work can be modified without considerably increasing Powerlink's security risk profile.

The other non-demand-driven network capex includes a wide variety of projects ranging from the purchase of system spare transformers through to energy management system upgrades and communication system works. While it could be argued that some of these projects would best be categorised differently (i.e. replacements or even augmentations in the case of fault level based works), in general they are of relatively low value and there should be no issues in incorporating them into the ex-ante allowance as proposed by Powerlink.

4.6 NON-NETWORK CAPEX

4.6.1 General

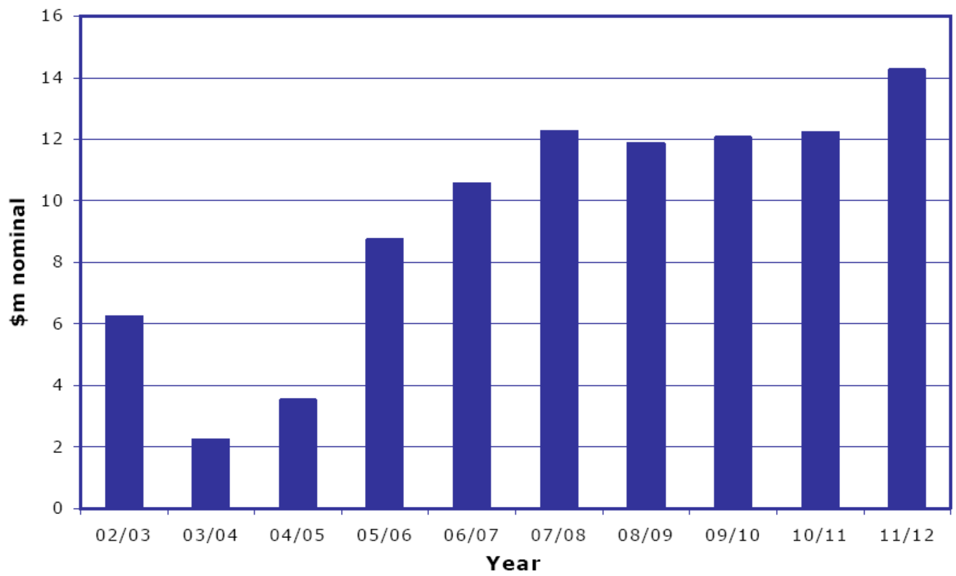
Powerlink has produced a detailed Non-Network Development Plan that is categorised into Business Information Technology (IT) and Support the Business. With $57.38 million forecast for Business IT and $46.34 million for Support the Business, this represents 4.2% of the entire forecast capex.

4.6.2 Business Information Technology

Business IT includes digital technology infrastructure and applications and is further subdivided into IT Replacements, which covers hardware and cyclical upgrades, and IT Projects which covers infrastructure or application based projects.

As shown in Figure 4-15, the requirement for capex in this category is expected to remain relatively constant over the review period. However, this is after a significant increase between 2003/04 and 2005/06.

Figure 4-15: Historic and Forecast Expenditure on Business IT



Source: Powerlink Revenue Proposal, p75

The IT Replacement schedule adopted by Powerlink includes age based replacements of desktops, laptops, monitors and printers every three years and switches, servers and routers every fourth year.

In reviewing Powerlink's average annual expenditure on desktops and laptops and other cyclic replacements we see a consistent cycle with no considerable increase. We also note that, on average, the $1.15 million expenditure for desktops/laptops represents around 300 units based on a cost of around $4,000 per unit. This appears reasonable and we recommend that all the forecast replacement based IT costs be included in Powerlink's capex allowance.

Powerlink's IT Infrastructure projects are driven by the need to maintain manageable, stable, secure and effective applications architecture. Each project is presented with a high level cost estimate and a relative priority compared with other projects in the program. Given the difficulty in forecasting IT projects due to the rapidly changing nature of information technology products and solutions, Powerlink has prepared a project by project forecast only to 2008/09. After that, it has been pragmatic and adopted a rolling three year average for the remaining years of the regulatory period.

We have undertaken a high level review of the scope, priorities and costs of the nineteen IT application projects and the ten IT Infrastructure projects that have been identified for the first two years of the regulatory period. We consider the range of projects to be comprehensive in nature and that a reasonable approach has been undertaken to establish the forecast. However, we consider that this level of expenditure does not appear to be necessary or efficient over the entire regulatory period, as evidenced by the considerable increase between 2003/04 and 2005/06. A number of the projects within this period of high expenditure appear to be one-off projects and on this basis we recommend that Powerlink's three year rolling average, used to establish its forecast capex between 2009/10 and 2011/12, be reduced by approximately 15% for both IT infrastructure and application projects, as per Table 4.26. The 15% reduction is a conservative estimate to reduce the level of Business IT capex to a level more commensurate with the long run average, including the capex over the current regulatory period.

Table 4.26: Adjustment to Business IT Forecast Capex ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink Proposal	11.9	11.2	11.05	10.89	12.34	57.38
Recommended Proposal	11.9	11.2	9.67	9.5	10.98	53.25
Change	0	0	-1.38	-1.39	-1.36	-4.13

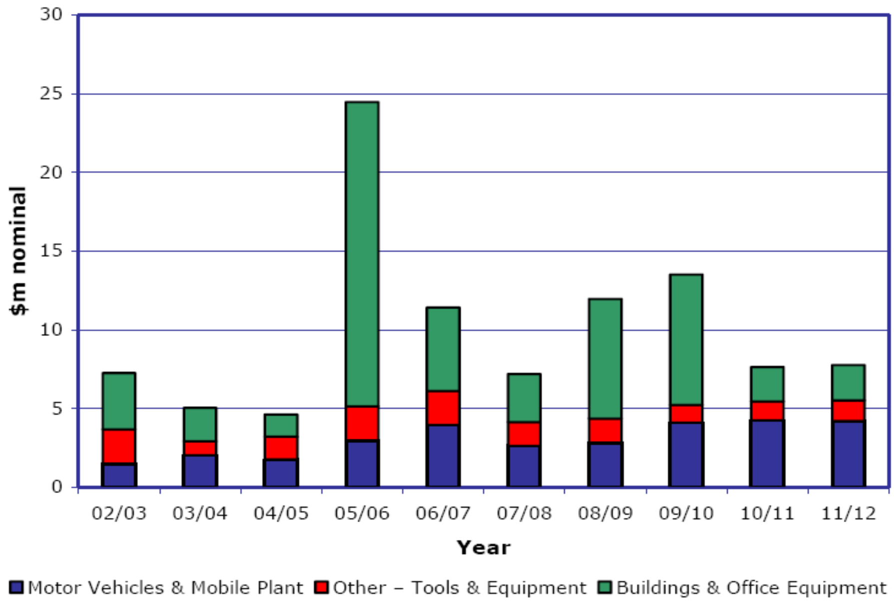
Source: PB Associates

4.6.3 Support the Business

The Support the Business category, with a forecast capex of $46.34 million, includes all other non-network related capital expenditure including buildings, office equipment and assets, motor vehicles and mobile plant and other specialist tools and equipment. Consistent with Figure 4-16, Powerlink's support the business capex is relatively constant with significant one-off expenditure in 2005/06 related to the Virginia Office Complex and further expenditure in 2008-10 related to additional warehousing and storage and a 'live' training facility.

Motor vehicles comprised $18.51 million, office buildings, infrastructure, furniture and equipment comprised $9.24 million, a new warehouse for storage was $6.21 million and a new live line training facility was $4.16 million.

Figure 4-16: Historic and Forecast Expenditure for Support the Business



Source: Powerlink Revenue Proposal, p76

In our review of Powerlink's motor vehicle and mobile plant expenditure, Powerlink indicated that the drivers for expenditure are the replacement of existing vehicles, as well as the purchase of additional vehicles for construction and additional maintenance. We note that Powerlink has adopted the methodology of escalating the number of 2006/07 vehicles it has in proportion to the expected number of staff employed by Powerlink over the regulatory period, while accounting for around 20% to be disposed of per annum. While the number of staff employed by Powerlink is expected to grow by 30% over the review period (from approximately 830 to 1080 employees), this results in only moderate annual increases in motor vehicle capex when accounting for the subtracted value of disposals. We consider the forecast level of capex for motor vehicles is reasonable and relatively consistent with historic expenditure.

The increase in capex for buildings across 2008/09 and 2009/10 is related to two one-off projects, a warehouse establishment for which we have reviewed the business case and a new transmission line training facility for which we reviewed the scope and estimate. Powerlink consider a number of alternatives to each of these projects and has presented costs that appear reasonable for the establishment of the respective facilities. We consider each of these projects is important to Powerlink's strategic development and recommend that the full expenditure be approved.

4.6.4 Conclusions on Non-Network Forecasts

Powerlink has prepared a well considered and strategic forecast of its non-network capex requirement. A large portion of this expenditure is ongoing, and trended consistently with historical expenditure, but it also provides for a logical and sound provision to support Powerlink's continued and significant network capex program over the forthcoming years. In particular, we fully support Powerlink's initiative to develop a new transmission line training facility, which will ensure that linespersons can develop new techniques for existing assets and refine maintenance practices, while it will also allow designers the opportunity to prototype new structures and hardware. This project will enhance Powerlink's capabilities across many aspects of its business.

In our review of the various components of the non-network forecast, we observed a genuine need for the majority of work, but consider that Powerlink has overstated its requirements for sustained IT projects towards the end of the regulatory period. We also observed that due consideration was given to various alternatives in its planning. We recommend that Powerlink's forecast non-network capex be included in its regulatory allowance except for the reduction in the IT capex forecast discussed in Section 4.6.2.

4.7 CONTINGENT PROJECTS

In accordance with the SRP, large and uncertain investments foreseen over the next regulatory period (that are associated with unique investment drivers not attributable to the actions of the TNSP) may be excluded from the ex-ante capex allowance if they lead to excessive windfall gains or losses.

To avoid the risk of excessive windfall gains or losses, the SRP specifies a materiality threshold to be applied to each contingent project, which is equal to 10% of the expected revenues from the project as a proportion of the expected revenues from the total ex ante allowance. A proxy for this threshold is 10% of the total forecast capex sought by Powerlink, or approximately $240 million.

The AER has some discretion with regard to the 10% threshold where it considers that the inclusion or exclusion of the project in the ex ante allowance may have the effect of leading to a windfall gain or windfall loss to the TNSP. The unique investment drivers, or triggers, associated with contingent projects must also be specific and unambiguous events such as the establishment of a new point load or power station as opposed to general investment drivers like load growth in a region.

The decision to allow investment on a contingent project occurs during the regulatory period if the trigger is realised and the need for the expenditure becomes known with greater certainty. A strong principle of the SRP is to maximise regulatory certainty by minimising the number of contingent projects and the potential for excessive regulatory burden. This is also anticipated in the SRP through the determination of a probabilistic based allowance that does not entail project specific approval - it is envisaged that some projects originally anticipated through general investment drivers such as load growth will not proceed and be replaced by others that were not identified during the revenue reset process.

According to the Decision Paper on the SRP, the rationale for treating a project as a contingent project is that "including the project in the ex-ante allowance would cause a substantial misalignment of the allowance with efficient costs over the regulatory period".[62]

4.7.1 Powerlink's Proposed Contingent Projects

Powerlink has proposed ten projects, as outlined in Table 4.27, to be classified as contingent projects and excluded from its main ex-ante capex allowance for the 2007/12 regulatory period. The projects were identified on the basis that, while Powerlink considers there is a possibility that they may need to proceed during the next regulatory period, they have not been included in any of the 40 scenarios from which the capex forecast was developed.

We note that the indicative costs of all these projects are well below the 10% materiality threshold specified in the SRP. However, given the number of these projects, and in particular the cumulative risk Powerlink could face if a number of these speculative projects were to proceed, we recommend the AER consider reducing the materiality threshold to a quite conservative $50 million (compared with the indicative threshold of $240 million), which would allow some of these projects to be excluded from the main capex allowance.

To assist in our assessment, Powerlink provided supplementary information regarding the timing, size and location of these projects, as well as details of the scope of works underpinning the indicative project costs. Of the ten projects, eight are specifically related to new load points. Powerlink has stressed that these eight point load driven projects (identified with an asterisk in the trigger column in Table 4.27) have not already been captured in demand forecasts underpinning the probabilistic ex-ante capex allowance.

Table 4.27: Powerlink's Proposed Contingent Projects, Triggers and Costs

Project Name	Trigger	Indicative cost $m
QNI Upgrade - QLD Component	Passes the "net market benefits" limb of the Regulatory test	100 #
Supply to Queensland Rail for "Missing Link"	Additional supply points for new section of railway line *	70
Augmentation of supply to SEQ	Significant changes in generation pattern in SQ	50
Ebenezer 330/275/110kV Establishment	Mooted "point load" Industrial developments west of Ipswich*	40
Yabulu 275/132kV 300MVA Transformer	Mooted "point load" Industrial development in Thuringowa area*	25
Stuart North 132/66kV industrial substation	Mooted "point load" industrial development in Stuart North area (Townsville)*	10
Nebo to Moranbah 275kV DCST & Lilyvale to Dysart 132kV SCST	Coal mining demands in the Bowen Basin expand at levels materially above the load forecast*	17 – 115
Biloela to Moura SCST	Mooted additional industrial load in Biloela area*	17
Nudgee establishment and 275 kV Nudgee – Murarrie	Change of reliability standard, or higher than forecast demand at Brisbane airport*	100
Desalination plant in SEQ	Approximately 80 MW point loads requiring new 275/110 kV injection and upstream augmentation *	37

The allocation of project works and therefore costs between Powerlink and TransGrid are yet to be finalised.

Source: Powerlink Revenue Proposal, p83

Our assessment of whether each of the ten projects identified qualifies as a contingent projects is considered in turn:

1. QNI Upgrade – QLD component: We note that, while the impacts of the QNI upgrade scenario on the rest of the network has been captured by the QNI++ theme set, the costs of the interconnector upgrade itself were not. The likelihood of the QNI upgrade proceeding was identified as 30%, its timing was prior to summer 2010/11 and it did not introduce a material change in the probabilistic

62 SRP Decision Paper p58.

weighted forecast capex. The indicative cost of this project of $100 million exceeds our proposed materiality threshold and the trigger is the justification of the project through the net market benefits limb of the Regulatory Test. The NSW component of this project has also been included as a continent project in TransGrid's 2004 revenue cap decision. On this basis we consider this project should be treated as a contingent project.

2. Supply to Queensland Rail for "Missing Link": This project relates to four new 30 MW connection points to electrify a new railway track in Northern Queensland. The timing is late 2012. Easement acquisition and the development of four 132/50 kV substations are required. Powerlink has advised that the specific trigger for this project is the decision by Queensland Rail to electrify the track section for coal haulage. We note that this decision was expected in July 2006. On the basis that a commitment to proceed has not yet been made, we recommend that these combined projects not be treated as contingent projects because the majority of expenditure is likely to be delayed and fall within the 2012-17 regulatory period.

3. Augmentation of Supply to SEQ: This network project relates to a variation to the timing of generating planting assumptions in SEQ made under the probabilistic scenarios. Given the supporting advice on this matter, we consider that a qualified trigger is valid and as the estimated project cost of $50 million exceeds the materiality threshold. We therefore recommend that the project be treated as a contingent project.

4. Ebenezer 330/275/110 kV Establishment: This network project is triggered by an overload of the Energex network in SEQ in the event that a large industrial and commercial area is developed. The timing is unknown, the size of the point load is unknown, the development requirements are quite speculative and the estimated project cost of $40 million is less than the materiality threshold. On this basis we consider the project should not be treated as a contingent project.

5. Yabulu 275/132 kV 300 MVA transformer: This network project is triggered by an overload of the Ross transformers in Townsville in the event that a large industrial development proceeds. The timing is unknown, the size of the point load is unknown, the development requirements are quite speculative and the estimated project cost of $25 million is less than the materiality threshold. On this basis we consider the project not be treated as a contingent project.

6. Stuart North 132/66 kV substation: This network project is triggered by an overload of the Ergon distribution network in Townsville in the event of a large industrial development. The timing is unknown, the size of the point load is unknown, the development requirements are quite speculative and the estimated project cost of $10 million is less than the materiality threshold, and on this basis we consider the project not be treated as a contingent project.

7. Nebo to Moranbah 275 kV DCST & Lilyvale to Dysart 132 kV SCST: This is a package of three network projects that are anticipated to be required to support increased demand from major mining companies in the Bowen Basin area over the next five years. The trigger is an additional point load of 30 to 80 MW. However the exact magnitude, timing and specific location of the new demand is uncertain – therefore the network development is highly speculative. One of the projects is estimated at approximately $90 million, which exceeds the materiality threshold. On this basis, we consider the Nebo-Moranbah 275 kV DCST line project should be treated as a contingent project triggered by the commitment of a point load of greater than 50 MW in the Bowen Basin.

8. Biloela to Moura SCST: This network project is triggered by an overload of the 132 kV network to Moura in central Queensland in the event of increased industrial development in the area. The timing is expected in around 2008 and

the estimated project cost of $17 million is less than the materiality threshold, and on this basis we consider the project should not be treated as a contingent project.

9. Nudgee establishment and 275 kV Nudgee-Murarrie line: This network project is triggered by either an increase in demand in the Brisbane airport area or a change to an N-2 reliability standard. The timing of any such triggers has not been established, nor specific information about the potential constraints. The estimated project cost of $100 million exceeds the materiality threshold. While we would expect any decision to change a reliability standard would require considerable public consultation due to the potentially material economic impacts, such a change is beyond the control of Powerlink and is therefore a risk it may face. On this basis, we consider the project should be treated as a contingent project and that it should be triggered by a change in the reliability standard for Brisbane airport.

10. Desalination Plant in SEQ: The original project related to a speculative new 80 MW point load being committed in SEQ. During our review, the Queensland government committed to investment in the construction of a large water desalination plant to be constructed on the Gold Coast[63]. The actual demand to be supplied is 70 MVA, the timing of the project is for late 2008 and the estimated project cost is $37 million. Given that this large additional load was not implicit in Powerlink's forecasts when preparing its Revenue Proposal, and irrespective of project estimate being slightly lower than the materiality threshold, we consider the project should be treated as a contingent project as the likelihood of the project proceeding is very high.

In assessing Powerlink's proposed contingent projects, we conclude that the projects outlined in Table 4.28 qualify as contingent projects.

Table 4.28: Recommended Contingent Projects, Triggers and Costs

Project name	Trigger	Indicative Cost, $m
QNI Upgrade – QLD component	Justification of the project through the net market benefits limb of a Regulatory Test application.	100
Augmentation of Supply to SEQ	Significant changes (greater than 3 years from assumptions) in generation pattern in SQ	50
Nebo to Moranbah 275 kV DCST	Commitment of a point load of greater than 50 MW in the Bowen Basin near Moranbah.	90
Nudgee establishment and 275 kV Nudge-Murarrie	Changes to the reliability standard for Brisbane Airport.	100
Desalination plant in SEQ	Approximately 70 MVA point load requiring new 275/110 kV injection and upstream augmentation.	37

Source: PB Associates

Many of the drivers for projects that we have recommended not to be classified as contingent projects are unspecified industrial developments. While we are reasonably satisfied, based on advice from Powerlink, that none of these are explicitly included in the load forecasts used in the probabilistic scenario analysis underpinning Powerlink's forecast capex requirement, it is possible that a number of these projects may be implicitly captured in the high demand growth scenario. In reality, apart from energy intensive major projects, the location of all new industrial load is speculative and it is likely that, while Powerlink's actual transmission development will mainly include projects drawn from the range of projects included in the probabilistic analysis, it will also include

[63] Refer to public statement by Queensland Deputy Premier: http://www.sdi.qld.gov.au/dsdweb/v3/guis/templates/content/gui_cue_cntnhtml.cfm?id=46704

a small number of projects that have not yet been identified by Powerlink. On this basis, we consider the removal of these projects from the contingent list will not materially increase the risk faced by Powerlink in supplying these speculative load points.

4.7.2 Contingent Projects Included in Ex-ante Allowance

As part of our review of Powerlink's forecast capex, the 'M50++" theme set[64] has been identified and analysed in an attempt to capture the sensitivity to a significant point load occurring within the probabilistic based ex-ante allowance. The possibility of the point loads in the M50++ theme proceeding was identified as relatively small by ROAM Consulting and attributed a probability of only 10%. While this approach did capture the sensitivity, we consider the scenario is better addressed through the use of contingent projects and that it should be removed from the theme sets. The projects in Table 4.29 are exclusively associated with the M50++ theme and should be removed and packaged appropriately to be triggered based on the commitment of a major industrial load greater than 500MW in the Gladstone area of central Queensland. The combined cost of these projects is $240 million and exceeds the recommended materiality threshold.

Table 4.29: Unique projects to the M50++ theme sets

No. of Scenarios	Probability	Project Code	Project Title	Total Capex in review period
8	11%	CP.01280	Gladstone Area Transmission Reinforcement	128.58
8	11%	CP.01971	Larcom Creek Remote 132 kV bus Establishment[65]	9.39
2	2%	CP.01615/D	Auburn River Switching Station (3 switched circuits)	12.71
3	4%	CP.01615/C	Auburn River Switching Station (4 switched circuits)	27.78
1	3%	CP.01615	Auburn River Switching Station (2 switched circuits)	17.28
4	15%	CP.01916	Gladstone Zone 120 MVAr No. 2	2.00
4	10%	CP.01784	Calvale 275 kV Substation Refurbishment	43.16
Total				**240.9**

Source: PB Associates

Powerlink has indicated that the removal of the M50++ theme set and the redistribution of its 10% top-down weighting evenly across the M50 and M10 themes sets reduces the overall forecast capex by approximately $15.7 million.

We are also satisfied that, even though some very large capex projects only occur in very few scenarios, none of the remaining projects included in the main ex-ante capex allowance qualify as contingent projects because they have all been established within the bounds of the combined theme sets used in the probabilistic approach. None of the remaining projects appear to be triggered by a unique driver, although this is difficult to exhaustively conclude given the large number of specific generation projects underpinning the transmission plans.

[64] The M50++ theme set represents a unique driver which is associated with two 500 MW step changes in industrial load in central Queensland within the Gladstone State Development Area in 2009/10 and 2010/11.

[65] This project is additional to the Larcom Creek project in the ex-ante allowance (CP 1958), which has been triggered by the committed 40 MW project at Wiggins Island. The Gladstone redevelopment and Larcom Creek 132 kV bus extension transferred to contingent projects (CP 1280 and CP 1971) have a much bigger scope which is primarily mutually exclusive of that required for the Wiggins Island development in order to account for a much larger load (in excess of 500MW).

4.8 COST ACCUMULATION PROCESS

This section describes general adjustments made to Powerlink's project cost estimates in order to translate them into an annual profile of capital expenditure. This process has been undertaken for each of the 40 transmission plans, and includes matters such as the escalation of costs for labour and material over time, the timing of projects, the determination of expenditure profiles, risk adjustment factors and other related matters.

4.8.1 Cost Escalation Factors

In establishing its annual forecast capex requirement over the review period, Powerlink has adopted cost escalation factors for all of its project estimates as outlined in Table 4.30.

Table 4.30: Powerlink's Proposed Escalation Rates for Forecast Capex

Item	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
Annual Labour Escalation	1.0769	1.0583	1.0560	1.0560	1.0560	1.0560
Annual Other Escalation[66]	1.0270	1.0291	1.0291	1.0291	1.0291	1.0291
Annual non-urban property compensation	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500
Annual urban property compensation (nominal)	1.0861	1.0861	1.0861	1.0861	1.0861	1.0861

Source: Powerlink

We note that Powerlink has escalated its easement acquisition costs by the long term appreciation trend of Australian grazing property index for non-urban properties, which has been 5% per annum real over the past 25 years for Qld. For urban properties, Powerlink has used 10 year average growth in Brisbane and Townsville local government areas of 8.61% per annum nominal. These are reasonable benchmarks to use for determining easement escalation rates for the different types of land.

Generally in accordance with our assessment of the labour escalation rates applicable to Powerlink's forecast opex, as discussed in Section 5.5.4, we recommend the annual labour escalation factors for Powerlink's future capex be reduced, as shown in Table 4.31. However, on the basis that a large proportion of the design and construction associated with Powerlink's forecast capex is being competitively outsourced, these recommended rates incorporate a small reduction over the years 2006/07 and 2007/08, when compared to the escalation rates recommended for opex. This further reduction brings the recommended annual escalation rate for capex over the period 2006-08 in line with that recommended for use after the expiration of Powerlink's current EBA.

Table 4.31: Recommended Labour Escalation Rates for Forecast Capex

Item	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
Annual Labour Escalation	1.0560	1.0560	1.0560	1.0560	1.0460	1.0460
Reduction in Annual Labour Escalation from Powerlink's proposal	-0.0209	-0.0023	-	-	-0.0100	-0.0100
Cumulative Reduction in Labour Escalation	-2.090%	-2.455%	-2.592%	-2.737%	-4.134%	-5.666%

Source: PB Associates

66 The "Annual Other Escalation" rate applies to all capital expenditure except labour and property compensation and includes materials and electrical plant.

The impact on Powerlink's proposed forecast capex program, assuming the labour cost comprises 30% of the entire forecast[67], due to this recommendation is presented in Table 4.32.

Table 4.32: Impact on Forecast Capex due to Reduced Labour Escalation Rates ($m, 06/07)

Item	2007-08	2008-09	2009-10	2010-11	2011-12	TOTAL
Powerlink Proposal	546.30	543.02	456.10	466.49	437.32	2,449.24
Recommended Proposal	542.28	538.79	452.36	460.71	429.89	2,424.03
Change	-4.02	-4.22	-3.75	-5.79	-7.43	-25.21

Source: PB Associates

Powerlink has applied the cost escalators in the following manner to determine its annual expenditure (which is stated in constant 2006/07 dollars) over the regulatory period:

- The capital cost of each project has been estimated assuming current (05/06 dollar) costs;
- The expenditure profile in each year of the regulatory period is determined based on pre-defined generic S-curves based on project type;
- The escalation factors shown in Table 4.30 have been applied to the estimated labour and "other" components of the project to give the estimated cost in nominal dollars for the years in which the expenditure is forecast to occur.
- These costs are then de-escalated at CPI (2.91%) to give the estimated project cost in 06/07 dollars.

The treatment of S-curves and cost escalation factors are illustrated in Table 4.33 and Table 4.34, which reflect the application of Powerlink's cost escalation methodology for a specific project, (CP.01195/A) Larapinta 275/110/33 kV Substation Establishment, which is a $50.6 million project (05/06 dollars) and is required in October 2010. The 24 month S-curve that applies to this project is shown in Table 4.33, where the cost contributions shown are cumulative.

67 This is a reasonable assumption as Powerlink has identified that within its BPOs that labour accounts for 30.5%, 25.8% and 50% of line projects, feeder bay developments and transformer costs, respectively.

Table 4.33: S-Curve Application for Substation Project, CP.01195/A

S-curve period	Cost distribution %	Months Oct commissioning	S-curve period	Cost distribution %	Months Oct commissioning
1	6.6	11	13	31.6	11
2	6.7	12	14	37.8	12
3	7.9	1	15	41.4	1
4	9.0	2	16	51.6	2
5	9.9	3	17	59.5	3
6	12.7	4	18	74.6	4
7	14.4	5	19	84.8	5
8	16.7	6	20	88.8	6
9	21.5	7	21	94.3	7
10	22.3	8	22	97.5	8
11	24.9	9	23	98.9	9
12	27.7	10	24	100.0	10

Source: Powerlink

Table 4.34 shows (i) the application of a 2.6 % risk adjustment factor to the costs estimated by Powerlink's cost estimation group, (ii) the application of the S-curve to allocate the total expenditure in $05/06 to the years in which this expenditure is forecast to occur, (iii) the escalation of the costs in each year to nominal dollars using the relevant cost escalation factors, and (iv) the de-escalation of these costs at CPI to constant $06/07. The risk adjustment factor is discussed in Section 4.8.6.

Table 4.34: Regulatory Allowance for CP.01195/A ($000)

Item	Type	Project costs	Risk adjusted Amount (+2.6%)	Risk adjusted amount by year					Total
				2007/08	2008/09	2009/10	2010/11	2011/12	
Expenditure $,000, 05/06	Total	50,598							50,598
	Labour	12,657	12,986	0	2,172	9,356	1,458	0	
	Other	37,941	38,927	0	6,511	28,046	4,370	0	
Escalated nominal expenditure	Labour			0	2,614	11,890	1,956	0	
	Other			0	7,082	31,392	5,033	0	
Expenditure $,000, 06/07	Total			0	9,156	39,713	6,232	0	55,101

Source: Powerlink

A range of key BPOs used by Powerlink to estimate the cost of projects are escalated in Table 4.35 to illustrate the impact of Powerlink's proposed escalation factors over the next regulatory period. Since the labour escalation rates are greater than CPI, the BPOs increase at a rate greater than CPI.

Table 4.35: Representative Escalated BPOs ($000, nominal)

Year	275 kV DC Sulphur Line – per km	275 kV AIS Feeder bay	275/132 kV transformer 375 MVA
05/06	541	1,914	3,935
06/07	564	1,990	4,140
07/08	585	2,064	4,321
08/09	608	2,139	4,507
09/10	631	2,217	4,702
10/11	655	2,299	4,906
11/12	680	2,383	5,120

Source: Powerlink

4.8.2 Project Timing and Implementation: Use of Generic S-curves

For each individual project that does not have a detailed implementation plan[68], Powerlink has used a generic S-curve to estimate the forecast capex required. These S-curves are based on historical project expenditure profiles. In practice, the application of the generic S-curves results in the realistic scenario that most of the capex is incurred well in advance of the project commissioning date.

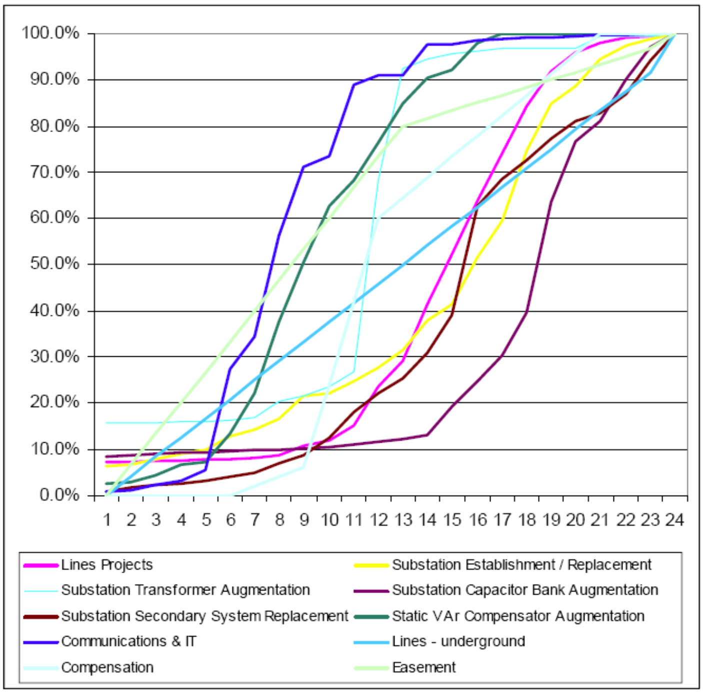
We note that Powerlink has identified about 150 projects where commissioning is required after the end of the next regulatory period (i.e. beyond 30 June 2012), but where, due to the application of generic S-curves, a portion of the actual project capex is forecast to fall within the 2007-12 regulatory period. In these cases the generic S-curves are used to determine that portion.

As shown in Figure 4-17, Powerlink has established 10 (adjusted)[69] generic S-curves that cover the majority of projects. These S-curves have been normalised over a 24 month period, which is the typical length of transmission construction projects. The curves are applied by project type to determine the incidence of expenditure in each financial year, working back from the nominated commissioning date.

68 Detailed implementation plans only exist for those projects that are imminent.

69 We note that Powerlink adjusted its original S-curves and this is discussed further in Section 4.8.3.

Figure 4-17: The (adjusted) generic S-curves used to develop Powerlink's forecast capex.



Source: Powerlink

Powerlink supplied background information to support the construction of each of the ten generic S-curves. The information showed that Powerlink had developed seven of the S-curves based on a simple average of a number of 'typical' historical projects. Four of these curves have also been adjusted in accordance with the following Section 4.8.3.

In general the averaging approach appears sound and while we note that some of the curves appear to be protracted given the nature of the project (e.g. those for capacitor banks and secondary system replacements), we are satisfied that the S-curves established using historical projects are suitable for the purposes of Powerlink's forecast capex, subject to the discussion in Section 4.8.3. We note, however, that we did not review each of the historical projects and highlight that there was reasonable variation across each of the projects used to determine the average. We would also have expected to see more projects used to determine the averages, as in five of the seven generic S-curves cases reviewed, there were fewer than three historical projects used. While some degree of variation can be expected across similar types of projects, the variation across each of historic S-curves was considerable and this indicates that there is scope for Powerlink to tune its commercial procurement arrangements to defer its actual expenditure compared with the generic S-curves on which the forecast capex was based. However, any commercial gain that Powerlink might obtain would be small relative to the potential errors in the forecasting process.

4.8.3 Adjustments to Historic S-curves

Powerlink provided information on adjustments it made to four of its key project S-curves[70] to account for tightening market conditions in the supply of specialist transmission infrastructure. The key risk envisaged by Powerlink was delays in the delivery of plant, so it considered two options to ensure that plant and equipment are available for its projects as required:

[70] The original S-curves had been derived from the analysis of historic project information using the methodology discussed in Section 4.8.2.

- order equipment two months earlier than normally required; or
- pre-pay up to 25% of the cost of the manufactured items.

Powerlink concluded that the pre-payment option was preferred as it did not introduce risks associated with early ordering of plant for projects that had not been approved or for which the design was incomplete. Powerlink has therefore adjusted four of its historic S-curves to account for pre-payment of manufactured items.

The four historic based S-curves adjusted were those for lines projects, substation establishment/replacements, substation transformer augmentations and substation capacitor bank augmentations. Manufactured items account for 25%, 31%, 63% and 34% of the total project costs, respectively for these projects and therefore Powerlink adjusted to S-curves to incorporate pre-payments of 6.25%, 7.75%, 15.75% and 8.5% of the total project costs. In comparison with the unadjusted S-curves, this represents an advancement of this proportion of expenditure in each project by, on average, approximately 9 months. We note the significance of this adjustment as these four project types account for around 68% of all of Powerlink's forecast capex.

Table 4.36 shows the impacts of the s-curve adjustments for three typical projects, one for which all expenditure occurs within the 2007-12 regulatory period, one for which the expenditure spans across the current regulatory period and the next, and a third project for which the expenditure spans the 2007-12 regulatory period and the one after that.

Table 4.36: Project examples of impacts due to adjustments to S-curves ($m, 06/07)

Project, s-curve type	2006 - 2007	2007-08	2008 - 09	2009 - 10	2010 - 11	2011 - 12	2012 - 13	2013 - 14	TOTAL in reg. period
CP.1195/A, adjusted	-	-	9.16	39.71	6.23	-	-	-	**55.10**
CP.1195/A, historic	-	-	6.79	41.51	6.83	-	-	-	**55.12**
CP.1265/A, adjusted	7.59	33.02	5.19	-	-	-	-	-	**38.21**
CP.1265/A, historic	5.63	34.51	5.69	-	-	-	-	-	**40.20**
CP.1537/A, adjusted	-	-	-	-	-	5.80	47.00	1.05	**5.80**
CP.1537/A, historic	-	-	-	-	-	3.09	49.17	1.56	**3.09**

Source: Powerlink

To support its application of the S-curve adjustments, Powerlink states that current conditions for the purchase of electricity transmission infrastructure requires earlier ordering and reservation of manufacturing slots with equipment suppliers. While we have some understanding of the issues raised by Powerlink, we are not satisfied that the risks envisaged by Powerlink exist, as to a large extent they should already be captured in the historic S-curves. We do not expect that all historic projects reflected 'just in time" procurement. We also question whether the 25% pre-payment is an efficient or appropriate method to mitigate any such risk and we do not believe that such a pre-payment will be necessary for all projects of the nominated type or that they will be needed for the entire duration of the regulatory period. Furthermore, we highlight Powerlink's use of long term, high volume supply contracts to ensure timely delivery of long lead time critical items. On the basis of these considerations we asked Powerlink to re-run its cost accumulation process to quantify the impact of this adjustment.

After re-running its cost accumulation process, Powerlink advised that, while generally advancing the timing of capex requirements, the adjustment of S-curves for the tight supply conditions lowered the capital expenditure in the next regulatory period by $0.62 million compared with the use of the historic S-curves, as shown in Table 4.37 . This result is supported by the examples presented in Table 4.36, where it is seen that the net effect on the overall five year capex is small.

Table 4.37: Overall impact due to adjustments to S-curves ($m, 06/07)

S-curve type	2007-08	2008-09	2009-10	2010-11	2011-12	TOTAL
Historic	518.38	476.03	462.78	505.61	444.91	**2407.71**
Adjusted	523.64	480.17	463.33	501.19	438.76	**2407.09**
Change	5.26	4.14	0.55	-4.42	-6.15	**-0.62**

Source: PB Associates

The minor reduction in the overall five year forecast capex is caused by the result that more costs were advanced into the existing 2002-07 regulatory period than were advanced into the 2007-12 regulatory period from the subsequent 2012-17 regulatory period. Powerlink also indicated that the WIP component of the opening RAB increased by approximately $12.9 million as a consequence of the adjustment. On this basis, we recommend modifying Powerlink's forecast capex to reflect the historic s-curves and that the WIP component of the opening RAB for the next regulatory period be reduced by $12.9 million.

4.8.4 Project Commissioning Program

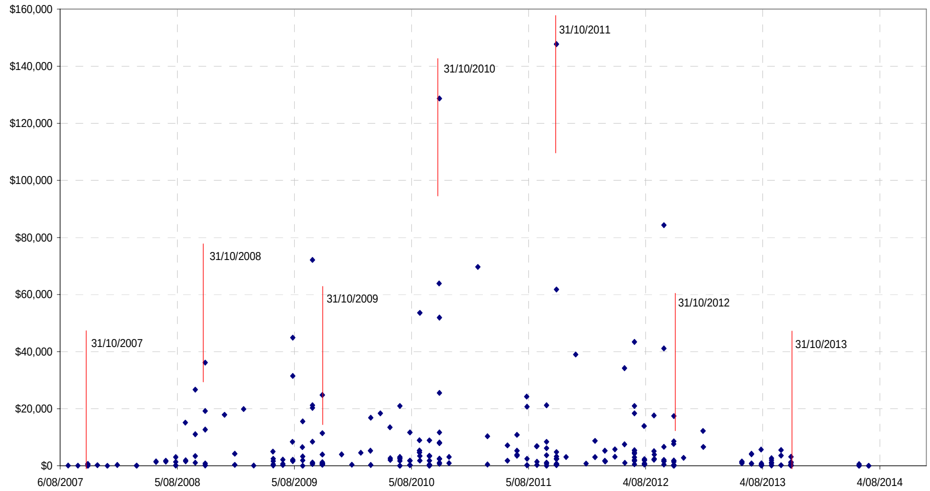
For demand driven investment, once the need for a project has been identified as part of the transmission planning process, the timing will be dictated by the need to complete the project prior to any significant risk exposure. On this basis, most augmentation or connection related projects are timed for commissioning by the beginning of the summer period. Given the large capex program required by Powerlink, it would not be practical or prudent to attempt to commission many projects in close proximity to one another. On this basis, the commissioning time for projects in Powerlink's forecast capex program are identified after considering the following holistic approach:

- A requirement for new projects to be commissioned prior to the summer trigger (i.e. the latest commissioning date is end of October);
- Any plant outages required, which would dictate windows of opportunity to allow for construction with minimal risk of supply interruptions (e.g. over shoulder periods May-September);
- Any linkages to other projects on the transmission or distribution network (i.e. requirements for pre-requisite works);
- Regulated connection projects as dictated by requested customer connection timing;
- Project management, construction and commissioning resources (including construction outage scheduling) will require a co-ordinated approach to deliver multiple projects prior to the summer trigger timing. This will require scheduling (advancement) of project commissioning dates to ensure all projects are delivered before the summer period.

This process considered those projects with comparatively smaller capex and less intensive resource requirements to be candidates for advanced commissioning. Network effects and co-ordination within each geographic area were also considered.

The outturn impact of this approach is that practical considerations dictated that some adjustments to the capital expenditure profile were necessary and Powerlink proposed such adjustments. To assess such impacts, we considered the deterministic commissioning program for one of the forty scenarios (Scenario 9), as shown in Figure 4-18.

Figure 4-18: Project Commissioning Dates vs. Project Value for Scenario 9.



Source: PB Associates

Figure 4-18 shows that commissioning of most of the more expensive projects is planned to occur prior to the summer period and that, as the cost of a project decreases, the commissioning date will be more evenly spread over the entire year. This is consistent with Powerlink's stated approach. However it means that numerous small projects will be commissioned before they are required and that the capex forecast provides for earlier project funding than would otherwise be necessary.

Given the extent of the overall capex program, and the beneficial practicalities of staggering project outages and commissioning times, and giving some consideration to our recommendation to remove the 25% prepayment adjustments incorporated into S-curves, we consider Powerlink's commissioning program is reasonable and we recommend no wholesale adjustment to the proposed project timings.

4.8.5 Short Line Adjustments and Location Factors

Powerlink has applied short line adjustment factors to a number of transmission line projects on the basis that typical line BPOs are developed using economies of scale with large projects that have line lengths approaching 100 km. As an example the 7.5 km South Pine to Nudgee 275 kV double circuit line has been costed with a short line adjustment factor of 187% applied to the BPO of $540,000 per km, effectively increasing the rate to over $1 million per km. We consider the magnitude of some adjustment factors to be disproportionate given the considerable program of works being undertaken by Powerlink over the forthcoming regulatory period and the opportunities for economies of scale. However having investigated the extent and principles behind the application of such factors, it became apparent that Powerlink had applied some discretion over the application of the factors - and in some cases had not applied them at all. On this basis, we recommend no change in Powerlink's forecast capex based on a review of the application of short line adjustment factors.

Powerlink has applied location factors to all its project cost estimates, including both line and substation projects, based on site locality and the vast geographic area that Powerlink's network covers. These location factors are direct multipliers of the capital city based cost of a construction type project, using Brisbane as the reference as recommended by quantity surveyors Rawlinsons. We consider the location factors adopted by Powerlink to be suitable for the purposes of developing its forecast capex, and while Powerlink has used some discretion in applying locality factors to transmission line developments between defined locations, we have found no evidence of the inappropriate application of the location factors.

4.8.6 Risk Adjustment Factor

Powerlink has identified that it often experiences actual project costs that are higher than the initial estimates, as its construction projects progress through to completion. To quantify this risk, Powerlink engaged consultants Evans & Peck to undertake a risk review of its capital works program[71].

The consultant's review examined inherent risks associated with the uncertainty in pricing a project of known scope in advance and it also captured contingent risks associated with events during the life of a project that were not envisaged during the original pricing. Each project forecast by Powerlink was classified as a high, medium or low risk. Each of these risk categories was then assigned a risk profile based on a Pert distribution. The uncertainty in each project's cost, based on "industry" experience, was assumed to be as follows:

Low Risk:	±10%
Medium Risk:	+20%, -15%
High Risk:	+35%, - 20%

After the consultant applied a Monte-Carlo technique to 500 potential forecast capex projects, the mean of the risk adjusted cost distribution was found to be 2.6% higher than the non-risk adjusted cost estimate. In its Revenue Proposal, Powerlink applied this 2.6% risk factor to all of its initial capital cost estimates (real 2005/06 dollars prior to their escalation) as part of its capex forecasting process (See Section 4.8.1). Powerlink did not apply any other contingency type cost adjustments to its cost estimates.

We note that the consultant has adopted a symmetrical distribution for low risk projects. Hence there is an equal probability of a cost increase as a cost decrease and therefore this category does not contribute to the 2.6%.

The medium and high risk categories are assumed to be skewed distributions with a higher risk of a cost increase than a cost decrease. The consultant's report does not quantify the various individual risks but takes a pragmatic approach to acknowledge that such risks exist. The probability distributions were determined based on the combined judgement and experience of Powerlink and its consultant.

The report states that the risks of cost changes in the cost risk categories include, amongst other things, issues associated with labour availability, changes in legal requirements and planning approvals, uncertain staging and outage costs, site variations, technology changes and difficulty in scoping and designing projects. We note that:

- Many of the listed uncertainties relate to items that are minor cost components of the projects. For example, the report states that substation (replacement and establishment) costing risk relates to decommissioning and disposal, staging (labour) and access. Applying an uncertainty of 80%-135% for these items on the total project costs appears unrealistic; given that the major cost components of substation projects is plant and equipment.

- Some of the listed uncertainties have been explicitly taken into account in the forecast capex and opex estimates. For example, the report states that for lines projects, costing risk relates to changes in legal requirements and planning

[71] Evans & Peck, 2006, *Risk Review of Capital Works Program*.

approvals, labour rates, plant and material cost increases and design risks. We consider each of these items, and risks associated with likely changes to these items, have already been factored into the cost estimates and capex forecasts, as discussed elsewhere in this report.

- The assumed risk profiles are not based on Powerlink's experience. The report provides no evidence to show Powerlink's actual history of cost overruns is material or of the order indicated.

- It is not clear that any cost uncertainties are not already built into Powerlink's BPOs. We understand that BPOs are updated on an ongoing basis to factor in actual historic project costs.

- The review only examines costing risk. It does not take into account some benefits. For example, a risk that a project may be deferred is likely to advantage rather than disadvantage Powerlink because it will have use of the forecast revenue until it incurs the cost of the project. Powerlink places a higher probability on projects being deferred than on being brought forward.

- If an allowance for risk is made in the revenue build up, the cost of the risk moves to customers, who are unable to manage that risk. Powerlink should only be compensated for non-diversifiable risks. The report does not make clear what part if any of the listed risks are non-diversifiable.

- The rate of return applied by the AER already incorporates a commercial risk factor.

We conclude that the consultant's report does not provide sufficient evidence to establish that a material costing risk exists and that it would therefore be inefficient to include such a risk factor as part of Powerlink's forecast. The impact of implementing our recommendation and removing the 2.6% risk factor from Powerlink's proposed forecast capex is shown in Table 4.38.

When coming to our decision on this matter we have also noted the various arguments Powerlink has used to provide assurances that it can meet its forecasts capex program, as discussed further in Section 4.9.

Table 4.38: Impact on Forecast Capex due to Removal of the 2.6% Risk Factor ($m, 06/07)

Item	2007-08	2008-09	2009-10	2010-11	2011-12	TOTAL
Powerlink Proposal	546.30	543.02	456.10	466.49	437.32	**2,449.24**
Recommended Proposal	532.10	528.90	444.24	454.36	425.95	**2,385.56**
Change	-14.20	-14.12	-11.86	-12.13	-11.37	**-63.68**

Source: PB Associates

4.8.7 Capacitor Bank Costs

Given the number of reactive compensation projects envisaged over the next regulatory period, Powerlink has derived generic project costs which it has applied to capacitor bank projects rather than costing each project individually. The standardised capacitor bank sizes are 50 MVAr at 110 kV and 120 MVAr at 275 kV. The methodology used to derive the generic costs was as follows:

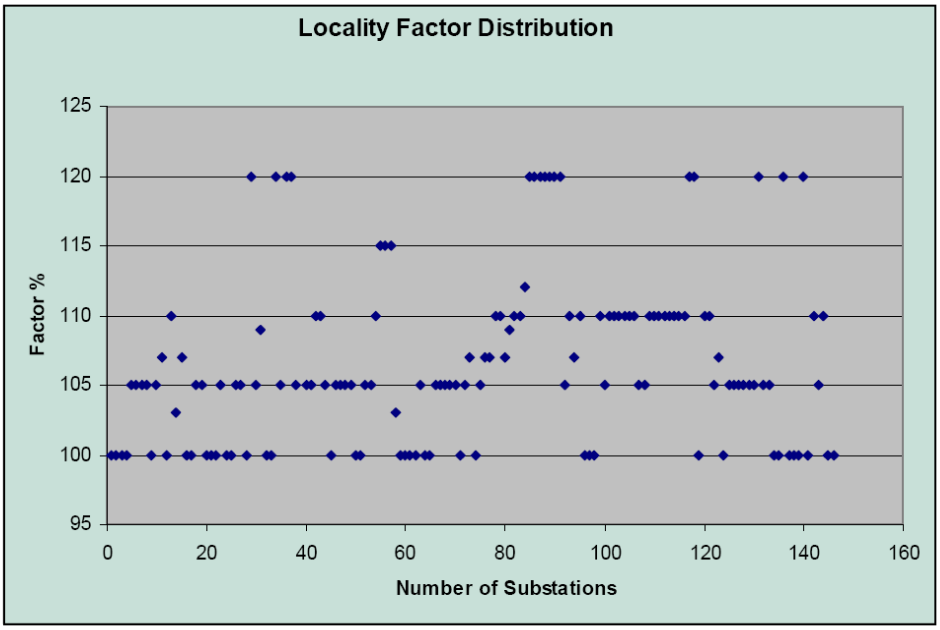
- Actual completed projects in both categories were analysed to derive relevant BPOs. Additional allowances and factors were applied to allow for site-specific conditions.

- These standard BPOs were then used to develop costs for 50 MVAr and 120 MVAr capacitor bank projects at different sites.

- From these site-specific capacitor bank projects the average cost for a 50 MVAr (132/110 kV) and 120 MVAr (275 kV) capacitor bank was determined. The two individual capacitor bank projects that most closely aligned with the 50 MVAr and 120 MVAr averages were then identified.

- As substation locality factors range from 100% to 120% across Queensland, an additional substation locality factor of 5% was applied to the estimates based upon the frequency distribution chart as shown in Figure 4-19, to account for the unknown site locations for expected capacitor banks.

Figure 4-19: Frequency Distribution of Substations and Locality Factors



Source: Powerlink

In reviewing the approach adopted by Powerlink to determine generic capacitor bank costs, we accept the need to develop such costs given the large number required as part of the forecast (approximately 47 in total). However, we consider it unnecessary to adopt a generalised locality factor, given that the final sites have been established. We recommend locality factors based on the final site be applied and consider this is likely to reduce the overall costs as the vast majority of capacitor banks are required close to the reference capital city of Brisbane. Our recommendation, based on reducing the locality factor from 1.05 to 1, is outlined in Table 4.39.

Table 4.39: Impact on reducing Capacitor Bank Locality Factor to 1.00 ($m, 06/07)

Item	2007-08	2008-09	2009-10	2010-11	2011-12	TOTAL
Powerlink Proposal	6.9	6.61	7.53	19.57	26.42	67.02
Recommended Proposal	6.555	6.2795	7.1535	18.5915	25.099	63.669
Change	-0.345	-0.3305	-0.3765	-0.9785	-1.321	-3.351

Source: PB Associates

4.8.8 Conclusions on Cost Accumulation Process

Overall, Powerlink has applied a systematic process to translate its individual project cost estimates (based on 05/06 costs) into an annual profile of capital expenditure over the next regulatory period (based on 06/07 costs). However, we make the following observations about the cost accumulation process:

- In our view, the labour escalation rate used by Powerlink over the regulatory period is too high and we do not think such levels will continue. However, the other escalation rates appear to be reasonable.
- Powerlink has identified the commissioning date of each project using a reasonable, logical and practical methodology that accounts for the actual need of the project and its ability as a business to deliver the program using finite resources.
- Powerlink has adopted the use of ten S-curves that are based on its historic experience. We consider that they are reasonable and representative for forecasting Powerlink's network related capex. The S-curves adopted should allow for some opportunity to realise minor efficiencies.
- Powerlink has incorporated adjustments into some S-curves to allow for pre-payment of manufactured goods to ensure deliverability. We do not consider this to be a reasonable approach and Powerlink provided limited evidence to demonstrate the envisaged risks, or the extent to which its approach would mitigate them. We consider these adjustments should not be applied so generally and recommend that they be removed.
- In our opinion, the short line adjustment factors used by Powerlink are not appropriate given its large capex program. However, Powerlink has applied these factors in a way that mitigates these problems in a manner that we consider reasonable.
- The process applied by Powerlink to develop location based cost estimates is reasonable.
- Powerlink's application of a general 2.6% risk factor to all cost estimates is not justified and we recommend that it not be applied.
- The generic locality factor applied to capacitor banks was inappropriate and should have been based on the actual location after the project was finalised.

4.9 ABILITY TO DELIVER CAPEX PROGRAM

As outlined in section 6.8 of Powerlink's Revenue Proposal, the following initiatives have, and will be, implemented to ensure Powerlink can deliver its increased capital program:

- the use of large, established and experienced contractors for its network construction;
- the application of a high degree of standardisation for new lines and transformers;
- the application of high level project management covering larger programs (as opposed to a project by project model), to capture economies of scale and provide a higher degree of certainty in ongoing work for sub-contractors;
- the use of long term, high volume supply contracts to ensure timely delivery of long lead time critical items;

- participation in the Asia Pacific Utilities Group to identify new, credible sources for materials and equipment;

- the adoption of a streamlined easement acquisition process to alleviate the risks of potentially more time consuming approval processes; and

- increased outsourcing of engineering design work, increased internal staffing and strengthened governance/management structures.

We have discussed these initiatives with Powerlink and agree that they will provide it with a higher degree of certainty so that it can deliver its forecast capex program, notwithstanding some uncertainty related to the realisation of some of the contingent projects. We do however have some concerns regarding Powerlink's ability to meet the project program associated with the high demand growth scenario and consider some of it to be unrealistic, especially in the early years of the review period. However, given the very low likelihood of this level of growth occurring, even more so after the recent summer 2005/06 experience where the actual demand supported the medium growth scenario, the chances that Powerlink will be required to service these demand levels by building the necessary projects is very low.

Like most project based infrastructure investment, the ability to deliver a program within a given time frame must be considered against two other factors, resources and costs. As identified previously, Powerlink is expected to place increasing demands on its use of specialist sub-contractors and to increase its own labour force by 30% over the review period, so it does appear the resources issue will be addressed. Powerlink also seems to be telegraphing its large capex program to the general construction industry as part of its current work program, so we have the impression that Powerlink's sub-contractors will be able to support it. This is also evidenced by considerable public reporting of the contracts that Powerlink has entered into for the ongoing construction and maintenance of transmission lines and substations.[72]

Furthermore, we note that Powerlink has identified that, while the capex program is 60%[73] larger than the previous review period, a significant proportion of this is due to increased costs as opposed to increased physical work. This is evidenced by Powerlink increasing its expected labour costs, its integration of adjustment factors into its S-curves for increased pre-payments to suppliers to guarantee delivery times, its use of a general 2.6 % risk factor, and by it establishing a warehouse to stockpile plant and equipment so that it can accept early delivery of high volume, standard equipment. We think some of these costs are inefficient and have made recommendations to remove risk factors and the pre-payment adjustment to S-curves proposed by Powerlink. We have also recommended a number of projects be reduced in scope, or deferred in timing through to the next regulatory period (2012-17).

Overall, we consider the amended capex program is achievable and that there is still reasonable scope for Powerlink to achieve some efficiencies and realise these efficiency benefits over the regulatory period.

In reviewing the main reasons why Powerlink's historical projects ran over budget or over time, we found that much of the overrun was due to legal opposition during easement acquisitions. Powerlink has now mitigated these risks by adopting approval through the designation process available through the Queensland Government. As a general rule, Powerlink appears to be able to meet its project timetables and we think this is managed by building sufficient margins into its project time frames and by the use of well established, governed and standardised procurement practices, which are documented in its Procurement Policy Manual. We also note that Powerlink has been proactive in determining the final commissioning dates of its projects to ensure that the annual work

72 Contract with Downer DEI, Courier Mail, Page 041 (Wed 28 Jun 2006).

73 Determined by Powerlink as the increase from $1.5 billion to $2.4 billion

load is staggered to account for its finite resources and in some cases projects have been advanced to ensure a more realistic workload.

4.10 OVERALL CONCLUSIONS OF FORECAST CAPEX

Powerlink has forecast a capex requirement of $2.45 billion (on an as incurred basis) over the next regulatory period. It has undertaken a comprehensive and systematic process to develop this forecast. The major components of this forecast relate to augmentation and replacement of its electricity transmission network.

We consider the themes and scenarios adopted by Powerlink for its probabilistic approach were plausible and comprehensive. They should capture most reasonable outlooks in Queensland over the review period. We consider the analysis, where the probabilistic weighted capex was less than that which would have been required under a deterministic medium load growth, 50% PoE approach, to be a reasonable basis for developing a capex forecast for use in the determination of an appropriate revenue cap.

We believe the approach adopted by ROAM Consulting to locate, size and then plant new generation of various technologies, as well as retire existing stations, has provided a reasonable basis for Powerlink's probabilistic based transmission planning.

Powerlink has undertaken a systematic and rigorous review of a complex network, and used advanced planning techniques to capture possible capex in the review period. However, through our detailed project reviews we identified a number of cases where an amended project scope or modified project timing would deliver more efficient outcomes. Our recommendations as a consequence of these observations are outlined in Section 4.11.

We consider that only five of the ten contingent projects proposed by Powerlink should be excluded from the main ex-ante revenue cap but that the Gladstone load development captured by the M50++ scenario meets the requirements for a contingent project.

4.11 RECOMMENDATIONS

As an outcome of our high level and detailed projects review of Powerlink's forecast capex requirements over the next regulatory period, we have identified a number of areas within which we believe Powerlink has overstated its capex requirements. On this basis, we recommend a reduction in forecast capex of approximately $407 million, or 17%. The basis of this recommendation is summarised in Table 4.40, which shows project specific changes on a year by year basis, and in Table 4.41, which shows the impact of systematic adjustments to be made to the entire (adjusted) capex program.

Table 4.40: Project related capex review (step 1) ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink proposal	**546.30**	**543.02**	**456.10**	**466.49**	**437.32**	**2,449.24**
Strathmore to Ross 275 kV DC	-	-1.47	-14.68	-0.71	-	-16.86
Larcom Creek 275/132 kV Substation Establishment	-4.43	-5.33	3.61	-	-	-6.14
Larapinta 275/110 kV Substation Establishment	-	-1.01	-4.40	-0.69	-	-6.10
275 kV DC Line into Larapinta	-	-	-	-7.32	-25.72	-33.04
Molendinar 275/110 kV Transformer Augmentation	-2.77	-10.62	12.90	0.56	-	0.07
Establish Halys 275 kV substation and Calvale to Halys 2nd 275 kV DC 1st stage (single circuit strung)	-21.36	-60.66	6.00	33.42	1.57	-41.03
Halys to Blackwall 500 kV DC Operating at 275 kV	-	-	-0.78	-7.79	-0.37	-8.95
Woolooga to North Coast 275 kV DC and 275/132 kV transformer	-	-	-1.57	-15.71	-0.75	-18.24
CQ No.1 132/33 kV Transformer	-	-	-0.39	-1.90	-2.47	-4.76
South Coast 500 kV DC easement acquisition	-	-	-1.79	-0.45	-9.32	-11.56
High level demand driven adjustment	-14.77	-9.93	-4.22	-4.10	-4.87	-37.89
Replacement Change	-	-	-53.10	-31.40	-26.10	-110.50
Capacitor locality factor	-0.35	-0.33	-0.38	-0.98	-1.32	-3.35
Line Security	-	-5.73	4.90	-13.69	1.51	-13.02
Substation Access	4.00	3.52	-3.31	1.24	-5.45	-
Business IT	-	-	-1.38	-1.39	-1.36	-4.13
M50 ++ removed	-1.00	-14.00	-4.00	2.30	1.00	-15.70
Aggregated change – Step 1	-40.68	-105.56	-62.59	-48.91	-73.65	-331.50
Recommended proposal – Step 1	**505.62**	**437.46**	**393.51**	**417.88**	**363.67**	**2,118.04**

Source: PB Associates

Table 4.41: Systematic capex review (step 2) ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Recommended proposal- post Step 1	505.62	437.46	393.51	417.88	363.67	2,118.04
Remove 25% pre-payments	-5.26	-4.14	-0.55	4.42	6.15	0.62
Remove 2.6% risk factor[1]	-13.15	-11.37	-10.23	-10.86	-9.46	-55.07
Adjust Labour escalation[1]	-3.72	-3.40	-3.23	-5.18	-6.18	-21.72
Aggregated change – Step 2	-22.13	-18.92	-14.01	-11.63	-9.49	-76.17
Recommended proposal – Step 2	**483.49**	**418.54**	**379.50**	**406.25**	**354.18**	**2,041.87**

Source: PB Associates
Note 1: The amounts recommended for removal of the 2.6% risk factor and the reduced labour escalation rates account for the Step 1 adjustment and therefore differ from those in Table 4.38 and Table 4.32, respectively, which were based on a reduction from Powerlink's original proposal.

The adjustments recommended in Table 4.40 and Table 4.41 do not include the impact of transferring a portion of the WIP component of the opening RAB into forecast capex as recommended in Section 3.7.

We do not believe that the recommended reductions in its allowed capital expenditure over the next regulatory period will materially degrade Powerlink's ability to meet its reliability based network obligations or detrimentally impact on Powerlink's service standards.

We also suggest that the AER should consider undertaking an additional review of Powerlink's demand forecasts - similar to the backcasting exercise undertaken by NIEIR for the Victorian and South Australian regions[74] - be undertaken to assess the accuracy of Powerlink's summer maximum demand forecasting outcomes prior to the decision on Powerlink's 2007-12 revenue cap.

We recommend the six projects shown in Table 4.42 be treated as contingent projects.

Table 4.42: Recommended Contingent Projects, Triggers and Costs

Project name	Trigger	Indicative Cost, $m
QNI Upgrade – QLD component	Justification of the project through the net market benefits limb of a Regulatory Test application.	100
Augmentation of Supply to SEQ	Significant changes (greater than 3 years from assumptions) in generation pattern in SQ	50
Nebo to Moranbah 275 kV DCST	Commitment of a point load of greater than 50 MW in the Bowen Basin near Moranbah.	90
Nudgee establishment and 275 kV Nudge-Murarrie	Changes to the reliability standard for Brisbane Airport.	100
Desalination plant in SEQ	Approximately 70 MVA point load requiring new 275/110 kV injection and upstream augmentation.	37
Gladstone load development	Commitment of a point load of greater than 500 MW in the Gladstone State Development Area.	240

Source: PB Associates

74 NIEIR, June 2005, *An assessment of the forecasting accuracy of the current summer MD forecast methodology for Victoria and South Australia: A backcasting exercise*.

5. OPERATIONAL EXPENDITURE

5.1 POWERLINK'S MAINTENANCE POLICIES, STRUCTURE AND PROCESSES

The asset owner, asset manager and service provider business model described in Section 2.3 is also designed to ensure efficient and effective asset management by separating the asset maintenance strategy and maintenance service provision functions. Consistent with this business model, Powerlink has structured its asset management function to clearly differentiate between plant management and work management. Accountability for Powerlink's plant management strategy rests with the asset manager and accountability for its work management strategy rests with its service providers. These two strategies are described in more detail below.

5.1.1 Plant Management Strategy

Powerlink uses techniques such as reliability centred maintenance (RCM) to optimise the performance of its assets. In order to minimise maintenance costs, Powerlink introduced in 2001/02 a structured RCM strategy known as RCM2. This is a process used to decide what must be done to ensure that its physical assets continue to provide the required performance. Initially Powerlink utilised external service providers to train its staff in the application of RCM2 but now has fully accredited internal trainers. The implementation of RCM2 is now well advanced and Powerlink estimates that the roll out at the end of the 2004/05 year was approximately 85% complete with the majority of the gains captured. It is anticipated that the implementation of RCM2 will be fully complete by the beginning of the next regulatory period.

The RCM2 process establishes what users want in terms of risk (safety and environmental integrity), quality (precision, accuracy, consistency and stability), control, comfort, containment, economy and customer service. It then identifies ways in which the system can fail while still meeting these expectations (failed states) and undertakes a failure mode and effects analysis to identify all the events which are reasonably likely to cause each failed state. Then, a structured process is used to identify a suitable failure management policy for dealing with each failure mode in the light of its consequences and technical characteristics. Failure management policy options include: predictive maintenance, preventive maintenance, failure-finding, changing the design or configuration of the system, changing the way the system is operated or run-to-failure.

We consider that Powerlink has applied and used the RCM2 process in a systematic and structured manner and that this produces appropriate, robust and cost-effective asset management programs, while at the same time delivering acceptable network performance outcomes.

5.1.2 Work Management Strategy

Powerlink uses both internal and external service providers to maintain, refurbish and operate its assets. Powerlink's asset management team has established long term service level agreements (SLAs) with its operation and maintenance service providers, from which work plans and performance targets are set and managed. SLAs have been negotiated with Powerlink's internal Network Field Services (NFS) and Network Operations business units and with an external service provider, Ergon Energy. Ergon Energy provides maintenance services in the central and northern regions of Powerlink's network and Powerlink's internal NFS group provides maintenance services in the southern region.

Powerlink's Network Operations Group is responsible for operating the system across all three regions. It established an asset monitoring team in the southern region in 2002 to assist in maintaining efficient levels of operational expenditure and acceptable network performance outcomes. The team concentrates on minimising emergency maintenance costs by remotely managing faults and monitoring asset performance. This results in faults being diagnosed and the network reconfigured remotely, reducing the need to dispatch crews to site and minimising restoration costs. The team is resourced by engineers and senior technical officers who have the experience to remotely interrogate secondary systems to identify root causes of faults and then reconfigure the network to restore supply. They are not directly involved with operating the system. The team has now been expanded to cover the three network regions.

In order to provide timely line patrols and general maintenance activities, which can be more efficiently performed by helicopter, Powerlink has contracted for the provision of helicopter services. Aeropower, the current contractor, keeps a helicopter available to provide a 24 hour 7 day service for emergency line patrols in the Northern Region, but provides these services over Powerlink's three regions as required. This arrangement provides a higher level of responsiveness in the difficult terrain of North Queensland. While Aeropower is the only supplier of aerial maintenance services in Australia, Powerlink has advised that the cost of using its services is similar to that of doing similar work using ground staff. The use of Aeropower also increases the speed at which activities such as line patrols can be provided and releases ground staff for maintenance works that cannot be performed from a helicopter platform.

In addition to live line work, Powerlink has introduced live substation work in order to continue to maintain assets whilst minimising outages. Powerlink advises that supply interruptions are becoming increasingly difficult to arrange during off peak times due to the very flat load profile in most of Queensland. The live substation crews are based in the southern region but also service the central and northern regions.

Powerlink believes that its implementation of SLAs using internal and external service providers replicates a commercially competitive environment since the costs, performance, and responsiveness of its two providers can be compared to leverage a "best practice" approach. Ergon Energy and Aeropower together undertake approximately 60% of Powerlink's maintenance services.

We have reviewed the arrangements Powerlink has in place with its service providers and consider that:

- Ergon Energy is the only organisation that is currently capable of providing 24 hour 7 day planned and unplanned maintenance services in central and northern Queensland. We do not believe that outsourcing these services through a competitive tender process would generate any significant cost savings;

- the current practice of negotiating SLAs with internal and external service providers provides a reasonable approach to manage costs and identify and leverage efficiencies;

- Powerlink appears to manage its SLAs in a manner that contains costs and it actively identifies and implements "best practice" maintenance procedures through the RCM2 process;

- the contract with Aeropower is appropriate considering the need to maintain helicopter availability in northern Queensland. Aerial patrols are the only way of providing a reasonable level of responsiveness for line fault patrols in an area as large and remote as northern Queensland;

- the SLA arrangement with Ergon Energy in northern and central Queensland avoids the need to fully fund depot, storage and supervisory functions. These costs are shared with Ergon Energy and result in an arrangement that delivers a very efficient outcome for Powerlink; and

- the introduction of RCM2 in combination with SLAs with Ergon Energy and internal service providers appears to be a significant factor in Powerlink achieving the lowest composite cost position in the ITOMS 2005 transmission line maintenance benchmarking study.

We have also reviewed the differences in maintenance cost in the three regions and found that:

- the work unit costs in northern region are higher than the other two regions due to the travel and accommodation costs incurred in providing maintenance services in remote locations;

- the substation and secondary systems work unit costs in the central and southern regions align within a few dollars;

- lines work unit costs in the central region are higher than in the southern region due to travel costs as the southern region is relatively compact and can easily be serviced from the depot at Virginia;

- communication work unit costs are higher in the southern region as the more highly technically qualified communication staff are based in this region and provide specialist support for the entire network. Hence the work unit costs in the southern region include travelling and accommodation costs; and

- Aeropower services are the same cost in all three regions.

As discussed in Section 5.3.2, Powerlink's operational expenditure (opex) benchmarks well against its peer utilities. We consider that this is due to the use of RCM2 and whole of lifecycle maintenance costing strategies together with the application of well managed and efficient SLAs with its service providers.

5.2 POWERLINK'S OPEX PROPOSAL

In its Revenue Proposal, Powerlink has categorised its operational and maintenance expenditure (opex) into controllable expenditure and other expenditure. Controllable expenditure includes direct operating and maintenance expenditure as well as support and corporate expenditure and insurance. Other expenditure includes contracted grid support costs, capex efficiencies, debt management and equity raising expenditure.

Controllable expenditure is considered relatively predictable and has been forecast on the basis of Powerlink's historical opex requirements. Conversely, grid support requirements are relatively unpredictable and can vary significantly from year to year. The remaining components of the "other expenditure" category represent adjustments to the proposed expenditure forecast that are not directly related to the operation and maintenance of Powerlink's network.

A comparison of the actual and expected controllable opex for the next regulatory period and the expenditure allowed in the ACCC's 2001 revenue cap decision is set out in Table 5.1.

Table 5.1: Comparison of Powerlink's Actual and Expected Controllable Opex with the ACCC's 2001 Decision ($m, nominal)

Item	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	Total
Decision[1]	65.64	71.97	76.43	80.40	84.51	89.43	468.38
Decision – CPI Adjusted	65.64	72.41	77.72	81.49	85.69[2]	90.84[2]	473.79
Actual	69.66	73.20	78.31	87.50	94.81[2]	107.01[2]	510.49
Variance[3]	+6.1%	+1.1%	+1.1%	+7.4%	+6.4%	+17.8%	+7.7%

Source: Powerlink Revenue Proposal – Table 7.1.
Note 1: Excludes grid support and QNI capex efficiencies.
Note 2: Forecast.
Note 3: Variance between Decision – CPI Adjusted and Actual.

Powerlink's opex forecast for the next regulatory period (2007-12), including both controllable and other expenditure, is shown in Table 5.2. The terms of reference for this review include consideration of all line items except the debt management and equity raising components of the "other expenditure" category. In relation to capex efficiencies we have only been requested to examine the efficiency claim relating to reinforcement of the Gold Coast supply.

During the course of our review we identified a mistake in Powerlink's opex model, relating to the corporate support projections. The error was caused by an incorrect formula used to derive the support projections. Powerlink has corrected the error and supplied us with a corrected model. The correction results in an increase in the corporate support requirement of $3.45 million over the next regulatory period. As a result the controllable opex requirement increases from the $631.49 million shown in Table 5.2 to $634.94 million. Our analysis is based on the revised figures.

Table 5.2: Powerlink's Opex Forecast 2007-12 ($m, 06/07)

Item	2004/05[1]	2007/08	2008/09	2009/10	2010/11	2011/12	Total[2]
Field Maintenance	26.08	34.81	38.04	41.08	44.11	47.63	205.67
Operational Refurbishment	15.15	18.60	19.60	20.65	21.76	22.93	103.54
New Requirements	-	1.87	1.94	2.01	2.08	2.15	10.05
Maintenance Support	7.66	9.05	9.50	9.93	10.36	10.82	49.66
Total Maintenance	**48.89**	**64.33**	**69.08**	**73.67**	**78.31**	**83.53**	**368.92**
Network Operation	**8.50**	**10.11**	**10.53**	**10.95**	**11.38**	**11.84**	**54.81**
Asset Manager Support	22.12	25.00	25.78	27.38	30.97	29.36	138.49
Corporate Support	11.12	8.24	8.41	8.58	8.75	8.93	42.91
Insurance	2.50	4.93	5.10	5.28	5.45	5.60	26.36
Total Opex Support	**35.74**	**38.17**	**39.29**	**41.24**	**45.17**	**43.89**	**207.76**
Controllable Opex	**93.13**	**112.61**	**118.90**	**125.86**	**134.86**	**139.26**	**631.49**
Grid Support		24.03	17.34	22.15	8.22	8.30	80.04
Capex Efficiencies		7.70	7.70	7.70	7.70	7.70	38.50
Debt Management		4.89	4.20	4.28	4.40	3.79	21.56
Equity Raising		2.47	2.47	2.47	2.47	2.47	12.35
Total Other Expenditure		**39.09**	**31.71**	**36.60**	**22.79**	**22.26**	**152.45**
Total		**151.70**	**150.61**	**162.46**	**157.65**	**161.52**	**783.94**

Source: Powerlink Revenue Proposal – Tables 7.8 and 7.11
Note 1: Base year – see Section 7.4.2 Powerlink Proposal.
Note 2: For 2007-12 regulatory period.

The average actual and projected controllable expenditure (in 2006/07 dollars) for the current regulatory period is $93.26 million per annum and the projected annual average controllable expenditure submitted in the Powerlink Revenue Proposal for the next regulatory period is $126.29 million, an increase of 35%.

5.3 FORECAST CONTROLLABLE OPERATING AND MAINTENANCE EXPENDITURES

The analytical process used by Powerlink to forecast its controllable opex includes the following steps:

- Determine the controllable opex in a base year (2004/05) by removing one-off items from actual expenditures;
- Confirm that the base year opex is efficient;
- Identify opex cost drivers and the impact of efficiency initiatives;
- Project the base year opex forward for each year of the regulatory period, taking into account projected changes in the cost drivers and the impact of any efficiency initiatives; and
- Confirm that the resulting opex forecast is efficient.

Each of the above steps is discussed in more detail in the following sections.

5.3.1 Determination of Controllable Opex in the Base Year

Powerlink has selected the 2004/05 financial year as its base year for developing its forecast controllable opex over the next regulatory period as this is the most recent year in which full data is available and for which the financial accounts have been audited. Powerlink also introduced the RCM2 program in 2001/02, which has reduced both routine and preventative maintenance costs. The roll-out of RCM2 was about 85% complete by the end of the 2004/05 financial year. We agree with Powerlink that many of the gains from the introduction of RCM2 would have been captured by the end of that financial year. Powerlink has removed one-off items from the base year.

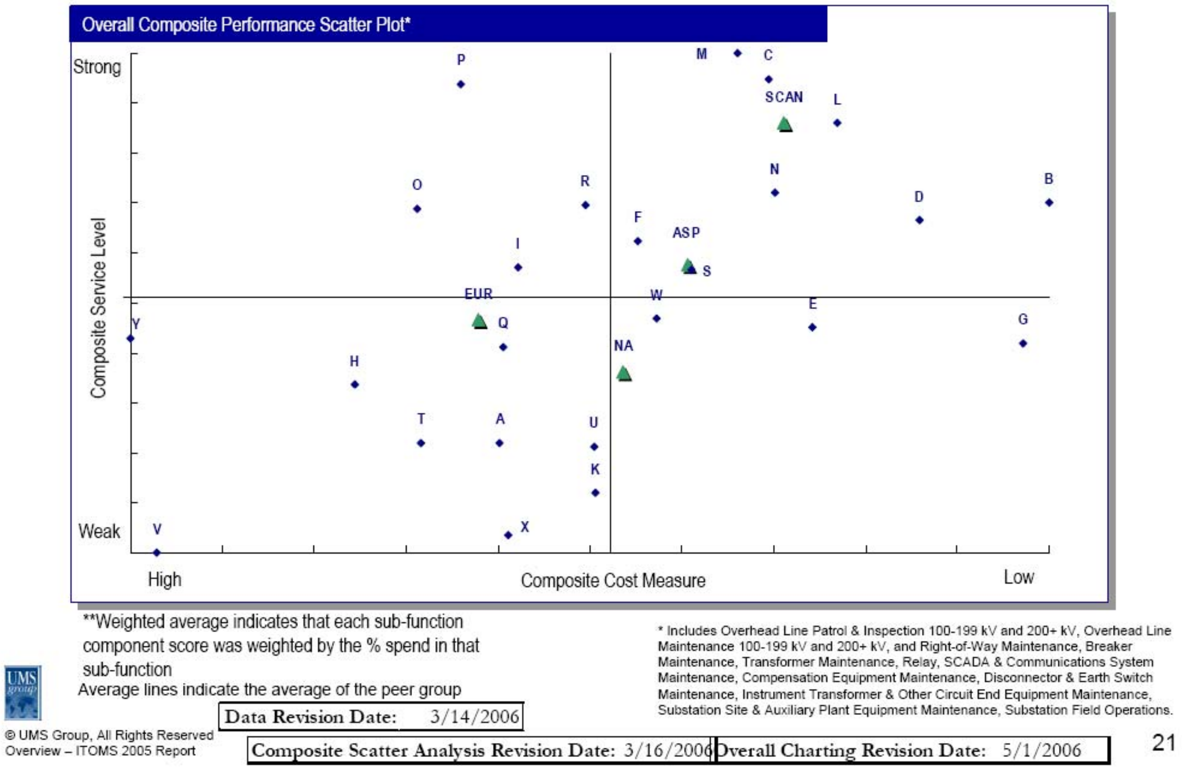
Powerlink's actual controllable opex (2006/07 dollars) for the 2004/05 year is shown in Table 5.2.

5.3.2 Confirmation that the Base Year Opex is Efficient

Powerlink has relied on benchmarking to confirm the efficiency of its opex and has included both International Transmission Operation and Maintenance (ITOMS) and ACCC benchmarking results in its Revenue Proposal. Powerlink participated in the 2005 ITOMS study, which involved TNSPs from the Asia Pacific, Europe, Scandinavia and North America regions. The study is done annually and focuses on the competing indicators of operation and maintenance costs and network reliability or performance. This study is organised by a steering committee representing transmission organisations from Australasia, Europe, United Kingdom and United States and managed by the consulting group UMS Group Inc. (UMS). It compares, at a detailed level, the comparative costs of individual maintenance functions and their associated outage service levels. The study is designed to provide insights into current 'best practice' work outcomes and identify opportunities for improvement by participants. The benchmarking results are presented as scatter plots of service level and cost.

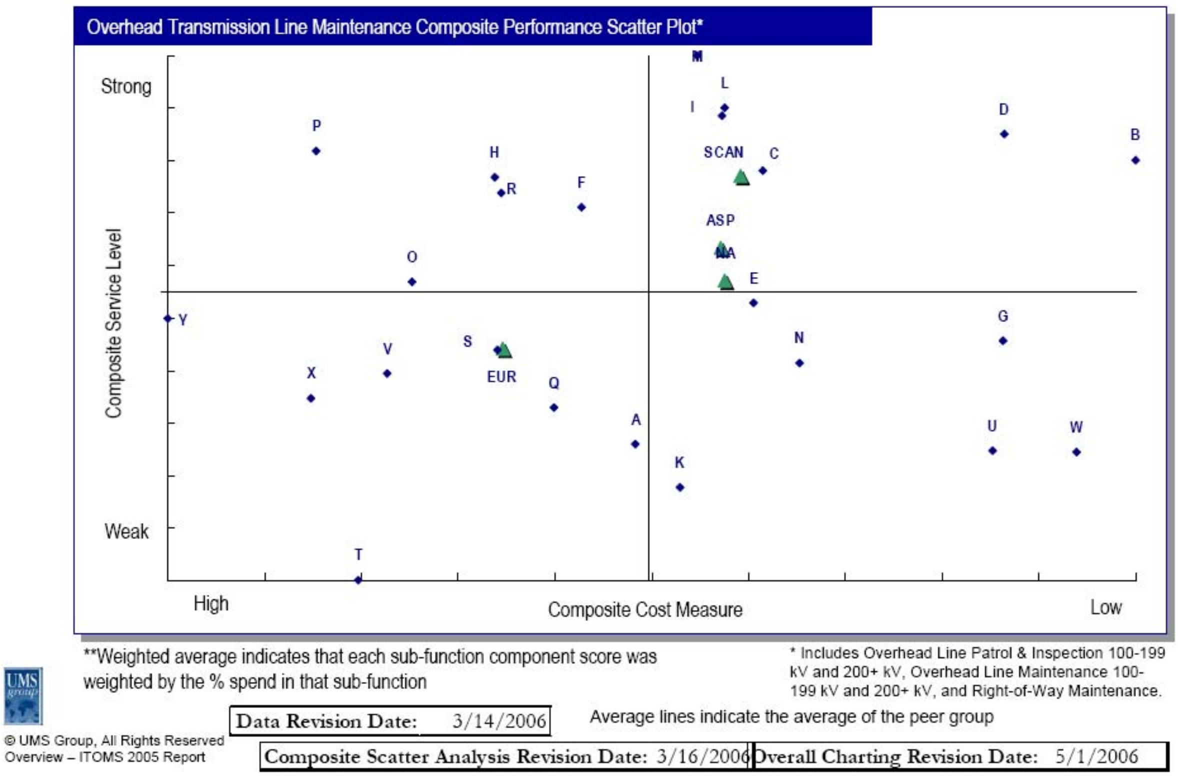
The ITOMS benchmarking results included in the Powerlink Revenue Proposal are detailed in Figure 5-1 to Figure 5-3.

Figure 5-1: ITOMS 2005 – Overall Composite Benchmark



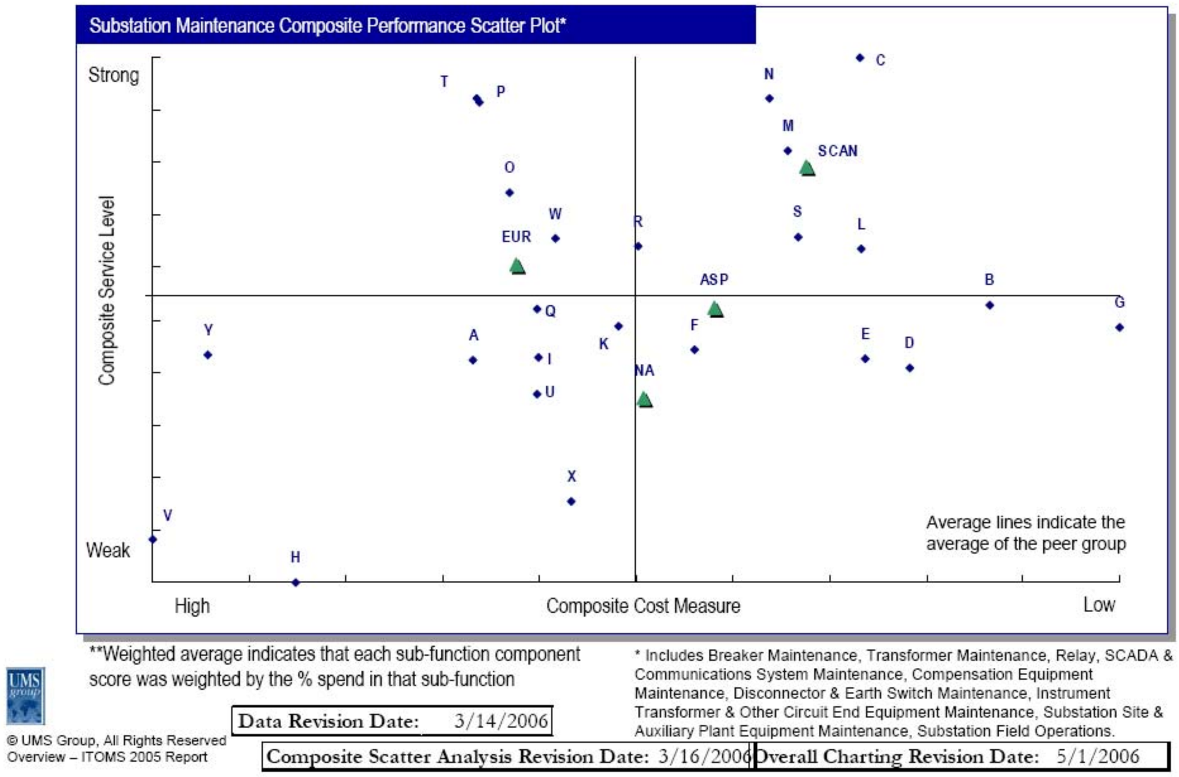
B=Powerlink; ASP=Asia South Pacific; EUR=Europe; NA=North America; SCAN = Scandinavia.
Source: UMS

Figure 5-2: ITOMS 2005 – Transmission Line Maintenance Benchmark.



B=Powerlink; ASP=Asia South Pacific; EUR=Europe; NA=North America; SCAN=Scandinavia.
Source: UMS

Figure 5-3: ITOMS 2005 – Substation Maintenance Benchmark



B=Powerlink; ASP=Asia South Pacific; EUR=Europe; NA=North America; SCAN = Scandinavia.
Source: UMS

The above scatter plots are composite plots prepared by UMS that take into account a range of different indicators. The best performing TNSPs are located in the upper right hand quadrant, indicating low costs and high service levels. We note that Powerlink benchmarks very well against its peer utilities. The ITOMS process includes procedures to ensure that participants include data necessary to achieve a like for like comparison between the businesses involved in each benchmarking study. However Powerlink has advised us that its composite cost measures, as shown in Figures 5.1, 5.2 and 5.3 exclude all operational refurbishment costs.

The ITOMS process includes procedures for controlling the integrity of the input data used for the study. The data required for each biennial benchmarking study is clearly defined at the commencement of each study and specifies which data is to be included or excluded from the study. In this way all benchmarking participants' data (and subsequent results) are compared, as far as is reasonably possible, on a like-for-like basis. The appropriateness of the inclusion or exclusion of participants' data is further examined during a review phase where all participants' data is assessed for completeness and appropriateness. The data submitted by Powerlink for the study was the audited data from 2004/05, and is taken from the same data set that was used by Powerlink to develop the base for its opex forecast in Powerlink's Revenue Proposal.

As discussed in Section 2.2, Powerlink has a high level capitalisation policy, which results in costs that would be capitalized by many utilities being treated as opex. For example, Powerlink treats circuit breaker replacements as opex whereas other utilities capitalise this cost. In the 2004/05 base year Powerlink's operational refurbishment costs amounted to 16% of its controllable opex (see Table 5.2). We understand that operational refurbishment costs are not treated opex in some ITOMS comparisons to correct for this, consistent with the ITOMS practice of developing cost benchmarks on a like-for-like basis, as far as reasonably possible.

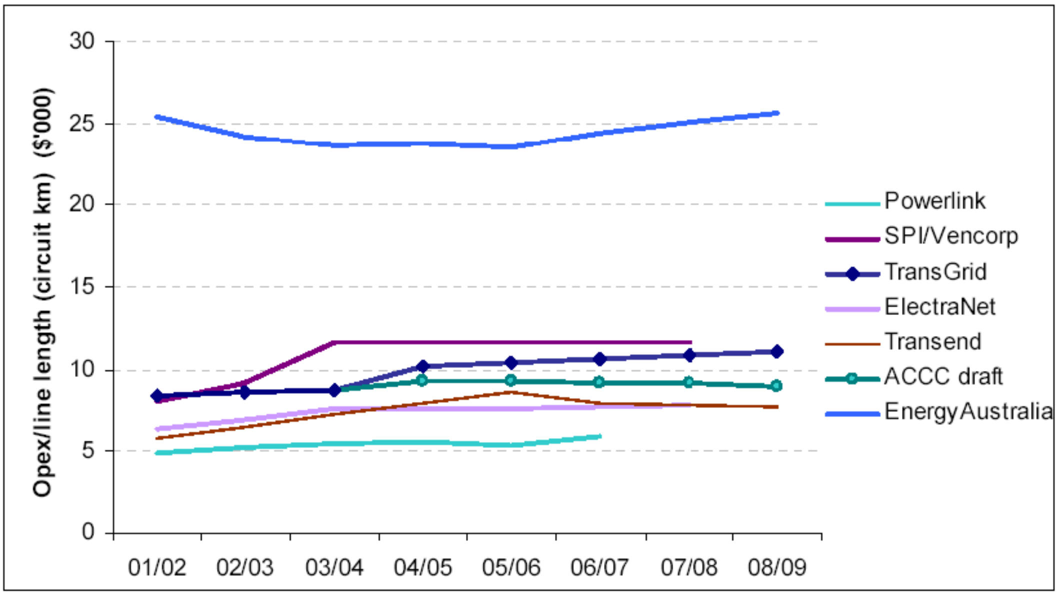
However, as discussed in Section 5.5.8, we estimate that only 46% of Powerlink's operational refurbishment costs relate to asset replacement or refurbishment and thus could potentially be capitalized. The remaining 54% of these generally relate to non-routine maintenance and would therefore be treated as opex by all TNSPs. If this component of Powerlink's operational refurbishment costs had been treated as opex for the purposes of these IOTMS comparisons, and included in Powerlink's composite cost measures as shown in Figures 5.1, 5.2 and 5.3, Powerlink would still have benchmarked very well against its peers.

This is demonstrated in Appendix J, which contains additional UMS scatter plots. Some of these plots benchmark performance against lifecycle costs, including refurbishment and replacement costs, and which are therefore not affected by the operational refurbishment issue. It can be seen that Powerlink, which is designated as TNSP "B", still benchmarks very well against its peers.

Powerlink has also benchmarked its performance against its peer Australian utilities using indicators considered by the ACCC to give a useful insight into relative TNSP performance. Comparisons of Powerlink's opex per kilometre of line length and opex as a proportion of the regulated asset base (RAB) with its peer Australian TNSPs are shown in Figure 5-4 and Figure 5-5 respectively. Again, while we believe that the Powerlink costs used for this analysis may be understated by about 9%, an adjustment of this amount does not significantly change Powerlink's performance relative to its peers.

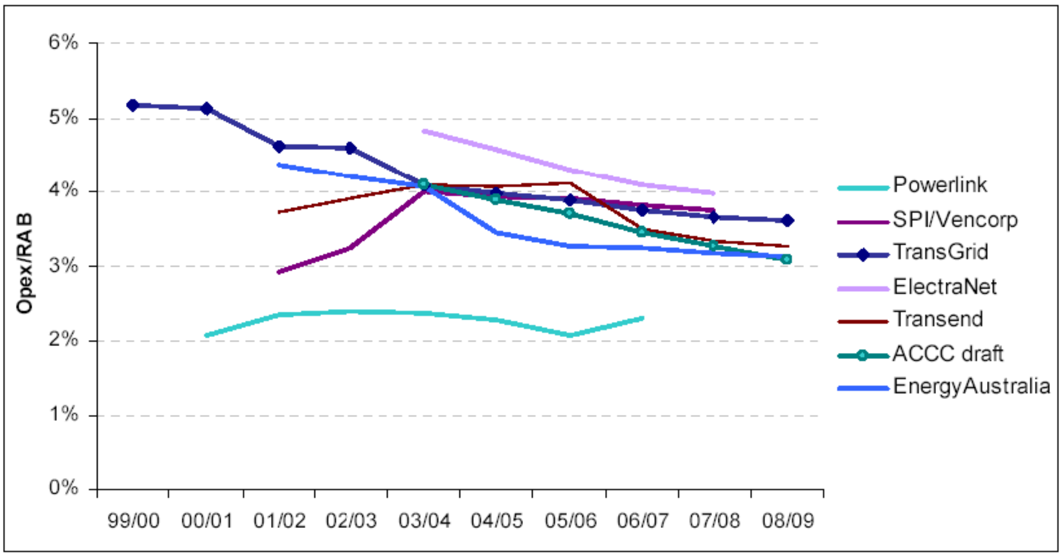
This is demonstrated in Figure 5-4 and Figure 5-5, where Powerlink's opex to line length and opex to RAB ratios (excluding operation refurbishment expenditures) are compared with other Australian TNSPs. Powerlink is the lowest cost operator on these indicators.

Figure 5-4: Comparison of Opex / Line Length for Australian TNSPs.



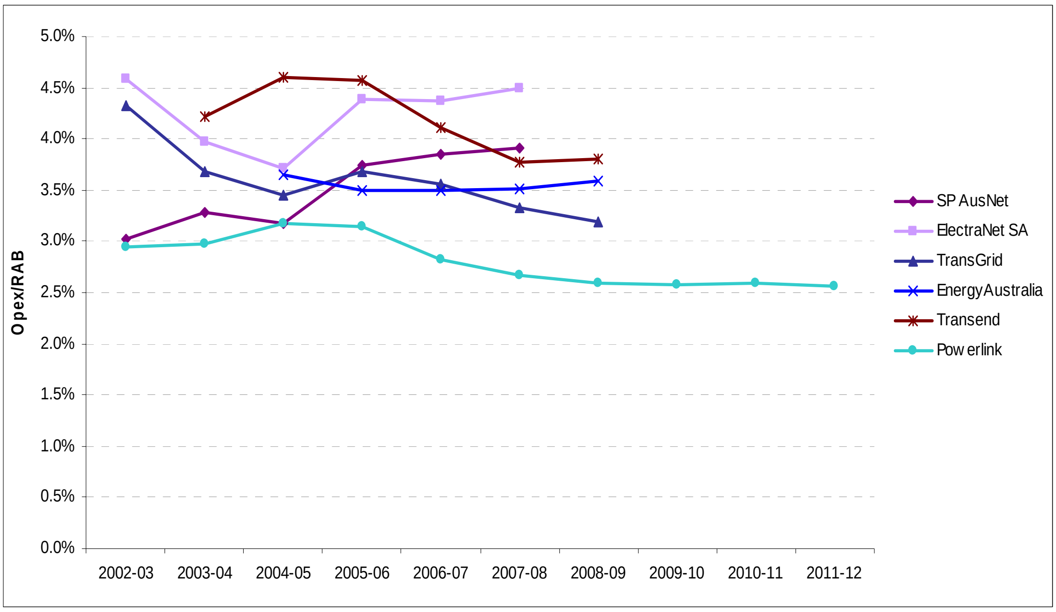
Source: NSW and ACT Transmission Revenue Cap TransGrid 2004/05 to 2008/09: Draft Decision (page 40)

Figure 5-5: Comparison of Opex / Regulatory Asset Base for Australian TNSPs.



Source: NSW and ACT Transmission Revenue Cap TransGrid 2004/05 to 2008/09: Draft Decision (page 40)

Figure 5-6: Comparison of Actual and Projected Opex / Regulatory Asset Base for Australian TNSPs.



Source: Information from AER regulatory reports 2006

Figure 5-6 is based on information contained in AER regulatory reports and Powerlink's opex includes operational refurbishment expenditures. Actual expenditures have been used up to and including the 2004/05 financial year and forecast expenditures for the remainder of the study period. Powerlink's forecast operational expenditures, as detailed in its Revenue Proposal, have been used. The study shows that Powerlink remains the lowest cost operator going forward.

These benchmarking results appear to indicate that Powerlink's current operation and maintenance practices and policies result in efficient outcomes. We note that the performance of a business is determined by a wide range of factors, many of which are business specific. Hence benchmarking results, while useful in identifying relative performance, should be treated with caution.

5.3.3 Identification of Cost Drivers and Impacts of Efficiency Initiatives

Powerlink has identified a series of cost drivers and efficiency initiatives that it considers will impact on its future opex requirements and has developed a series of factors to reflect the impact of these drivers/initiatives. These factors are incorporated into its opex forecasting model to reflect anticipated changes in the different cost drivers over the next regulatory period. These factors include:

- escalation factors for material and labour costs;
- impact factors to reflect asset refurbishment and vegetation management costs;
- a scale factor to reflect changes in network size;
- efficiency factors to reflect economies of scale;
- a reduction factor to reflect the impact of asset replacement on opex costs; and
- reduction factors for targeted efficiency factors.

The reasonableness of these assumptions and the robustness of the initial data are fundamental to the accuracy of the forecast. We have therefore investigated these cost drivers and efficiency initiatives to test for reasonableness and benchmarked them with external comparative data where possible. The results of this assessment are presented in Section 5.5.

5.3.4 Projection of the Base Year Opex Forward

Powerlink has developed a model to forecast its controllable opex over the next regulatory period. This model applies the factors identified above to the base year data to predict both the quantity of the future work effort and the escalated cost of this work. Overall forecast controllable opex is projected to increase by approximately 24% over the next regulatory period while Powerlink's RAB is projected to increase by 30%.

As noted in Section 5.2, during the course of our review we identified a mistake in Powerlink's opex model, relating to the corporate support projections. The error was caused by an incorrect formula used to derive the support projections. Powerlink has corrected the error and supplied us with a corrected model. The correction results in an increase in the corporate support requirement of $3.45 million over the next regulatory period. As a result the controllable opex requirement increases from the $631.49 million shown in Table 5.2 to $634.94 million. The analysis in the remainder of this section is based on the revised figures.

The treatment of the different controllable opex categories in the Powerlink model is described briefly below.

5.3.4.1 Field Maintenance

In forecasting its network maintenance costs over the next regulatory period, Powerlink has factored in expected cost savings resulting from the introduction of RCM2, as discussed in Section 5.1.1. This analysis is based on the premise that RCM2 will reduce the maintenance inputs required over the next regulatory period.

For the purposes of the analysis, routine maintenance costs are measured in "work units". A work unit is the cost to deliver approximately 8 hours of productive work. Hence it includes direct and indirect overheads such as travelling time and accommodation costs in order to facilitate the 8 hours of productive work and also material costs.

The cost estimate for condition based maintenance is developed by applying a ratio to the relevant routine maintenance cost. Similar ratio analysis is used to estimate total corrective and emergency maintenance costs. These ratios have been determined by the responsible asset strategists within Powerlink to reflect their best estimate of the full effect of the implementation of RCM2, as the historical ratios do not reflect the full impact of RCM2. Section 5.5.9 of this report includes a more detailed explanation of this process.

Once the total maintenance cost estimates have been developed, cost forecasts over the regulatory period are developed by applying cost escalators to network maintenance costs in proportion to the historical labour/material split[75]. Total network maintenance expenditures are then increased to allow for the expected growth in asset numbers and subsequently reduced by an efficiency factor to provide for anticipated operating efficiencies (resulting from asset growth economies of scale) over the regulatory period.

We have reviewed the labour/material splits used by Powerlink in its model. These ratios were determined by analysing data from its corporate financial system (SAP). Actual results for the last two or three years for the Powerlink service providers and corporate support functions were derived and applied universally. We consider that the 90%/10% labour/materials split for support functions, 70%/30% split for line and substation maintenance and 80%/20% split for secondary systems and communications maintenance are consistent with current industry norms.

Maintenance support (field support and other support) have been estimated by initially splitting the 2004/05 expenditures into labour and material costs using historical ratios. As noted above, the historical split for support functions was 90%/10% and this ratio has been applied to all costs in these categories in the Powerlink opex model.

In the model the labour and materials components are separately escalated by the total annual asset growth factor, and the annual labour or material escalation factor. The total annual material and labour costs for each cost category are then reduced by the economy of scale factors. For maintenance support the asset growth economy of scale factor used in the Powerlink opex model is 25% - this translates into 25% more work effort for a 100% increase in assets being managed. We consider this ratio to be reasonable.

Operational refurbishment has been estimated in the Powerlink opex model by developing a forecasting algorithm that closely predicted the quantity of annual operational refurbishment expenditure detailed in Powerlink's *2005 Network Operational Refurbishment Plan*. As the forecasting algorithm was based on input drivers including escalators and reduction factors, there were slight variations between the model and the actual expenditures in the Operation Refurbishment Plans, which was developed using a bottom up approach. We note that the algorithm produced a slightly lower overall expenditure than detailed in the Operational Refurbishment Plan.

5.3.4.2 Network Monitoring and Control, Asset Manager Support and Corporate Services

Powerlink has estimated expenditures for network monitoring and control, asset management support and corporate services using the same methodology. Initially the 2004/05 expenditures were split into labour and material costs using historical ratios. As noted above, the historical split for support functions was 90%/10% and this ratio has been applied to all costs in these categories in the Powerlink opex model.

In the model the labour and materials components are separately escalated by the total annual asset growth factor, and the annual labour or material escalation factor. The total annual material and labour costs for each cost category are then reduced by the economy of scale factors. For network monitoring and control the asset growth economy of scale factor used in the Powerlink opex model is 25% - this translates into 25% more

[75] In the model, different escalation factors are applied to labour and materials.

work effort for a 100% increase in assets being managed. We consider this ratio to be reasonable. For asset management support and corporate support the asset growth economy of scale factor used in the model is 10%. The relationship between work effort and asset growth is lower than for operations and we consider the 10% economy of scale factor to be appropriate.

5.3.4.3 New Requirements

The new requirements line item (see Table 5.2) captures the additional opex costs that will be incurred by Powerlink as a result of amendments to the *Workplace Health and Safety (WH&S) Act* 1995. These amendments require changes to current Powerlink work practices but will not impact on opex until 2006/07. As a result the changes are not reflected in the base year costs and are included in the forecast as a separate line item.

5.3.4.4 Insurance

Proposed insurance costs have been developed from a combination of broker estimates and an actuarial study to determine self insurance allowances (Section 5.5.12).

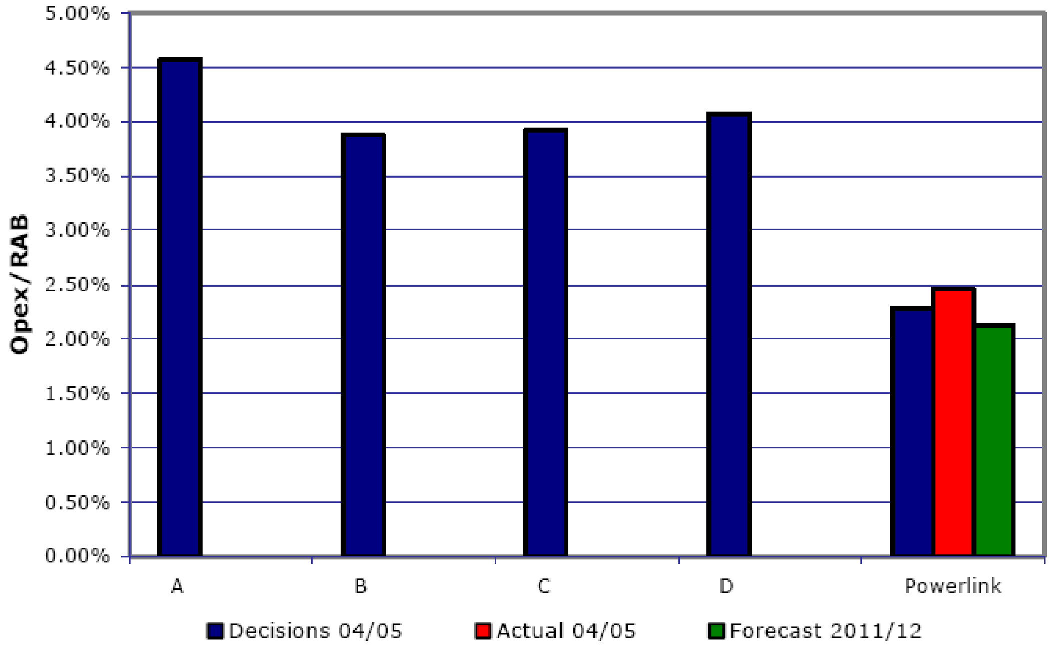
5.3.5 Confirmation that Resulting Forecast is Efficient

Powerlink has also relied on benchmarking to confirm that its forecast controllable opex is efficient by calculating the ratio of future opex to RAB and comparing the result with other Australian TNSPs.

For this analysis, Powerlink has used the ACCC calculations of the ratio of opex to RAB for the 2004/05 base year for its Australian peer utilities. It has compared this with its own ratios based on (i) the ACCC's 2001 revenue cap decision, (ii) its actual ratio of opex to RAB, with one-off line items removed, for the 2004/05 base year as determined from its audited accounts and (iii) its forecast opex to RAB ratio in 2011/12 based on the modelling in its Revenue Proposal. This comparison is shown in Figure 5-7. Based on this analysis Powerlink believes that its "opex costs will remain the efficient frontier in the coming period".

The data used to determine the Opex / RAB ratios in Figure 5-7 has not been normalised and hence this figure can only be used for illustrative purposes. We note that the inclusion of Powerlink's operational refurbishment costs in the analysis would slightly reduce the gap between Powerlink and the other Australian TNSPs.

Figure 5-7: Comparison of Opex/RAB Ratio with other Australian TNSPs



Source: Powerlink Revenue Proposal – Figure 7.9.
A (ElectraNet); B (TransGrid); C (SPI/VENCorp); D (Transend).

5.4 PB ASSOCIATES' APPROACH TO THE OPEX REVIEW

In undertaking this review we have investigated the underlying data and assumptions upon which Powerlink's controllable opex model is based. This included a detailed analysis of the base year data incorporated in the model and an investigation of the basis for each individual factor used to predict future maintenance effort and associated cost.

The insurance component of controllable opex has been assessed by reviewing insurance broker estimates of future insurance premiums as well as an actuarial report on estimates of uninsurable and uninsured losses.

Grid support expenditure projections have been reviewed by evaluating additional information from Powerlink regarding the methodology used to predict these forecasts. At the time of our review, negotiations had not been completed with potential grid support providers so only forecast expenditures are available (see section 5.6.1).

A similar approach has been used to investigate Powerlink's capital efficiency claim relating to the supply to the Gold Coast. Additional supporting data has been reviewed and a recommendation made (see Section 5.6.2).

Where appropriate, our recommended revisions have been input into Powerlink's opex model to determine a revised controllable opex requirement. Where our proposed changes could not be incorporated into the model, we have undertaken a separate analysis. A recommendation on what we consider to be an appropriate level of total opex is set out at the end of this chapter.

5.5 CONTROLLABLE OPERATIONAL EXPENDITURE

5.5.1 2004/05 Base Year Expenditure

We reviewed the actual 2004/05 opex as this is the base year expenditure that Powerlink has used for forecasting its opex requirement for the next regulatory period. The nominal total controllable operating cost for 2004/05 was $87.50 million compared to a consumer price index (CPI) adjusted controllable operating expenditure allowed in the ACCC 2001 Decision of $81.49 million. A significant proportion of this variation was a result of a one-off cost of $3.36 million due to the introduction of the new Powerlink enterprise bargaining agreement (EBA). Powerlink has advised that the other significant component of the variation was a $639,000 preparatory cost for this revenue review, which was not provided for in the ACCC's 2001 Decision. The remaining variation includes a range of small cost increases across the other opex categories, which we consider to be within normal forecasting accuracies.

We have confirmed that the one–off EBA and revenue reset related costs were not included in the base year cost data used as the baseline for forecasting controllable opex. Hence these costs have not been included in the escalated base cost and have not unduly inflated Powerlink's proposed opex requirement for the next regulatory period. In Powerlink's opex model projected revenue reset related costs have been included for the 2004/05, 2005/06 and 2006/07 financial years. Forecast expenditure to be incurred in preparing for the 20012-17 revenue reset has also been included for the 2009/10, 2010/11 and 2011/12 financial years.

The benchmarking analysis in Figure 5-1 shows Powerlink to be the operator with the lowest composite cost, whilst maintaining reasonable service levels. This relative efficiency is also shown in Figure 5-7, which shows that Powerlink benchmarks well against other Australian TNSPs when comparing opex to RAB ratios, even when operational refurbishment expenditures are included in Powerlink's opex.

We consider that the ITOMS benchmarking process has been well developed and the normalisation factors used have been refined over many years. In our experience ITOMS benchmarking indicates both the presence of good relative performance and areas for potential improvement. Whilst we acknowledge the limitations of benchmarking in identifying absolute efficiency, we believe that as a tool to identify and confirm relative efficiency it is reasonable, particularly when different studies support the same conclusion.

Nevertheless, we requested further supporting information to confirm the relative efficiency of Powerlink's maintenance activities and Powerlink provided more detailed information from the ITOMS report, which is included in Appendix J. The results are masked for confidentially purposes. Powerlink's position is marked with a "B". We note that in all cases Powerlink is positioned in the upper right hand quadrant, confirming it as a relatively efficient operator. This is also true for Performance Benchmark – Operational Line Maintenance 100-199 kV Including Replacement / Refurbishment Costs, Performance Benchmark – Overhead Line Maintenance 200+ kV Including Replacement / Refurbishment Costs, Performance Benchmark (Including Replacement / Refurbishment Costs) – Transmission Breaker Maintenance 100 -199 kV, and Performance Benchmark (Including Replacement / Refurbishment Costs) – Transmission Breaker maintenance 200+ kV scatter graphs which are based on lifecycle costs, and include Powerlink's operational refurbishment costs[76].

Generally it is extremely difficult for a TNSP with a network topography like Powerlink's to achieve best performer status due to the costs associated with maintaining assets over such long distances. Apart from the use of best practice asset management systems, we believe Powerlink's good performance is due to its ability to share depot, storage, supervisory and other overhead costs for the provision of maintenance services in the

[76] UMS Group, ITOMS 2005 Report

northern and central regions through its Service Level Agreement (SLA) with Ergon Energy.

Overall we consider that Powerlink's actual opex for the 2004/05 financial year, after adjustment for one–off costs, to be efficient and an appropriate basis from which forecast opex can be projected.

5.5.2 Maintenance, Network Operations and Asset Manager Support

To obtain opex forecasts for these cost categories, the base year costs (adjusted for one–off costs as appropriate) have been divided into labour and material components using historical ratios and these components were individually escalated using assessed escalation factors. As noted in Section 5.5.1 we consider the base costs used in the model to be reasonable.

The opex forecasts are very sensitive to the assumed escalation factors and therefore we have reviewed the basis for the escalation factors used in the Powerlink model. The key escalation factors are:

- legislative obligations;
- labour costs;
- maintenance materials;
- vegetation management; and
- asset growth.

The findings of our review into these escalation factors and a number of other issues (including operational refurbishment costs) are discussed in the sections below.

5.5.3 New Workplace Health & Safety Act Requirements

Amendments introduced in 2006 to the *Workplace Health and Safety (WH&S) Act* 1995 have resulted in significant increases in future compliance costs. A major impact has been a change to the definition of construction work, which has been widened to include activities such as refurbishment, repairs or augmentation. Powerlink has developed a detailed schedule of the impact of these changes on its current work practices and their associated annual costs. These costs range from the payment of levies through to work practice changes and workplace audit costs.

In addition, Powerlink will incur a one-off cost associated with developing new processes and systems to ensure compliance with the amendments to the WH&S Act.

We have reviewed the proposed changes to work practices and the costs associated with their implementation and consider them to be reasonable. A one-off implementation cost will be incurred in the 2006/07 financial year but this is not included in the projected expenditures for subsequent years. The recurring WH&S incremental expenditures have been projected forward by escalating the labour and material components.

5.5.4 Labour Costs

Labour costs comprise a large proportion of all maintenance costs and the applied escalation factor has a significant impact on the opex forecast. Powerlink has based its labour escalation factor on current EBAs which provide for annual labour rate rises of 5.6%. However these EBAs will expire in early 2008, shortly after the commencement of the next regulatory period. Nevertheless, Powerlink has assumed that labour costs will continue to escalate at this level throughout the next regulatory period and has used an escalation factor of 5.61% through to the end of the current regulatory period. For the 2006/07 year this factor was increased marginally to 5.83% to accommodate the impact of the current EBA.

Statistics released by the Australian Bureau of Statistics (ABS) in March 2006 indicate a 5.9% annual increase for electricity, gas and water supply workers in the short term.[77] The ABS data also indicates that the seasonally adjusted annual change for all employee jobs is 4% and in trend terms is also 4%. In addition, Average Weekly Earnings (AWE) deflators of between 3.75% and 4% are currently being used by actuaries to predict longer term wage impacts[78]. However, we have examined AWE historical data for Queensland full time adult workers' total earnings and found that the average compound increase has been 4.6% over the last 10 years.[79]

The maintenance of high voltage equipment is a specialised area. Technicians and tradespersons with the required training and experience are in short supply nationally, and particularly in Queensland because the growth in electricity demand is higher than elsewhere and because both Energex and Ergon Energy have accelerated their network augmentation and asset replacement programs following the release of the Somerville Report[80]. Indications are that the labour market for experienced electricity workers will continue to be very tight in the short term and we believe that this will allow above average wage rate increases to be negotiated for the next four years. However labour markets, like most other markets, are cyclical and we do not believe that Powerlink's assumption of labour cost increases of 5% to 6% compounding every year for the next 7 years is a likely outcome. Therefore we consider that 5.6% is an appropriate escalator for the first three years of the next regulatory period and 4.6% for the final two years. Year one of the next regulatory period has been marginally increased to accommodate the impact of the current EBA.

The industry has responded to the current labour shortage by substantially increasing the recruitment of apprentices and other trainees. This is supported by statistics released by the Commonwealth Government's National Centre for Vocational Education Research (NCVER) in July 2006. However, it will be another three years before these additional apprentices complete their trade training and they will then require a further period of at least 12 months to gain the necessary competencies. Once these trainees qualify and gain field experience, the pressure for higher than average wage increases in the industry is likely to abate. Based on this premise, we consider that the current underlying pressure on electricity workers wage rates will continue for at least the next four years (which includes the first three years of the next regulatory period) and then abate to a more reasonable level equivalent to the long term average wage growth for Queensland electricity and gas workers."

We therefore recommend that a labour escalator of 5.82% be modelled for the 2007/08 year, 5.6% for the 2008/09 and 2009/10 years and 4.6% for the 2010/11 and 2011/12 years. The escalation factor used in the 2007/08 year is slightly higher than the underlying rate increase of 5.6%, implicit in the current EBA, due to the timing of the implementation of that EBA.

Table 5.3 displays the impact of PB Associates' recommended labour escalation factors on Powerlink's forecast controllable opex, assuming all other variables in the model are held constant.

[77] ABS, Labour Price Index Cat No: 6345.0

[78] Refer to the recent submissions made to the Senate Enquiry into Superannuation and Standards of Living in Retirement.

[79] ABS, Labour Price Index Cat No: 6345.0

[80] Queensland Department of Natural Resources, Mines and Energy, 2004, Detailed Report of the Independent Panel, *Electricity Distribution and Service delivery for the 21st Century.*

Table 5.3: Impact of Revised Labour Cost Escalators ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink Revenue Proposal	113.11	119.49	126.54	135.64	140.16	634.94
Impact of Revised Escalation	113.10[1]	119.47	126.51	134.64	138.13	631.85
Variance	(0.01)	(0.02)	(0.03)	(1.0)	(2.03)	(3.09)

Source: PB Associates' analysis.
Note 1: Powerlink incorrectly used a 5.61% escalator in the analysis used for the Revenue Proposal. We have corrected this to 5.60%, which gives minor differences in the early years of the regulatory period.

5.5.5 Maintenance Materials

In forecasting expenditure it is not uncommon for DNSPs and TNSPs to model material costs to increase in line with inflation.[81] However, Powerlink has used a 4% material escalation factor in its opex forecasting model. It advised that, whilst material costs have recently shown increases of between 1% and 19% per annum, on balance 4% seemed a reasonable compromise. Powerlink has not attempted to determine its weighted average material annual cost increase and the 4% per annum appears to be its high level "best estimate" of a probable outcome. In spite of this, Powerlink assumed that material costs would increase in line with CPI in developing the capex forecasts used in its Revenue Proposal.

The recent volatility in the price of electrical equipment appears to be driven by volatility in raw material prices. We have researched recent prices on the London Metal Exchange (LME) for non ferrous base metals and note significant volatility over the past two years. This volatility may indicate that current prices are at or near the maximum for the current cycle. This is supported by the fact that forward prices, particularly for copper, now indicate sharp declines from their recent highs. For example the LME official prices for 23 June 2006 quoted a cash buyer price for copper a USD 6,710 per tonne and a 27 months forward contract buyer price of USD 4,965 per tonne.

Figure 5-8 and Figure 5-9 from the historical data section of the LME website indicate that the current price increases are a relatively recent phenomenon. Both graphs also indicate a recent downturn in prices. In addition, the price history for zinc, used for galvanising, displays a similar recent price increase but historical prices are relatively stable.

[81] For example, ETSA Utilities assumed that material costs would increase in line with CPI in its price proposal for its 2005 electricity distribution price review and Energy Australia forecast all non-labour costs to increase in line with CPI in its last submission to the Australian Competition and Consumer Commission in relation to its 2004/09 transmission revenue reset.

Figure 5-8: LME Aluminium Alloy Price Chart (USD/tonne)

Source: London Metal Exchange

Figure 5-9: LME Copper Price Chart (USD/tonne)

Source: London Metal Exchange

A recent article in the Australian Financial Review stated that the Australian Government's current budget incorporates an assumption that commodity prices will fall significantly in the next two to three years, and some economists believe that the fall in commodity prices could be sharper than the Treasury has forecast. In a recent report, the OECD notes that "the major uncertainty about the outlook for the Australian economy concerns the timing and the extent of the eventual downturn in commodity prices".[82]

The Australian Government's current budget incorporates an assumption that, for commodity prices, there will be "a fall in prices at some stage" and for that assumption "there are considerable risks associated with the technical assumption for commodity prices, particularly given the uncertainty around the future demand for resources and the associated supply response"[83]

82 The comments in this paragraph draw on an article from the Australian Financial Review of May 27, 2006 titled "The Economy".

83 Australian Government Budget Paper 1 Statement 3 Economic Outlook.

On balance we consider that escalating the base year material cost by CPI is appropriate. This approach also captures the current high material prices to the extent they are reflected in the base year (2004/05) opex costs and would align with the material escalation rates Powerlink has included in their capital project estimates.

We therefore recommend that material costs be escalated at CPI in Powerlink's opex model for the next regulatory period and the final years of the current period. The following table indicates the impact on Powerlink's forecast controllable opex by escalating material costs at CPI and assuming that all other variables in the model are held constant.

Table 5.4: Impact of Revised Materials Cost Escalators ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink Revenue Proposal	113.11	119.49	126.54	135.64	140.16	634.94
Impact of Revised Escalation	112.77	119.01	125.91	134.85	139.18	631.72
Variance	(0.34)	(0.48)	(0.63)	(0.79)	(0.98)	(3.22)

Source: PB Associates' analysis

5.5.6 Vegetation Management

Vegetation management expenditure includes all costs associated with the management of land and easements owned or controlled by Powerlink. In addition to vegetation control it encompasses, amongst other works, environmental management costs such as erosion and sediment control, weed management, access track maintenance and zone substation land management.

Powerlink argues that the new Vegetation Management Policy and Guidelines, issued by the Queensland Government in 2004 under the *Vegetation Management Act 1999* and the *Vegetation Management and Other Legislation Amendment Act 2004*, has had a significant impact on the vegetation control practices allowed on those easements impacted by the new policy. It has advised that easements covered by the Act (including urban easements) can require up to a 25-fold increase in effort to maintain. Powerlink claims that this increase in maintenance effort is a result of a significant increase in effort required during each maintenance cycle combined with substantially reduced periods between maintenance cycles. These additional costs include, but are not limited, to increased supervisory costs associated with endangered species identification, annual pruning cycles instead of the previous five yearly cycles, the need for selective pruning of incompatible species and the need to access easements by foot.

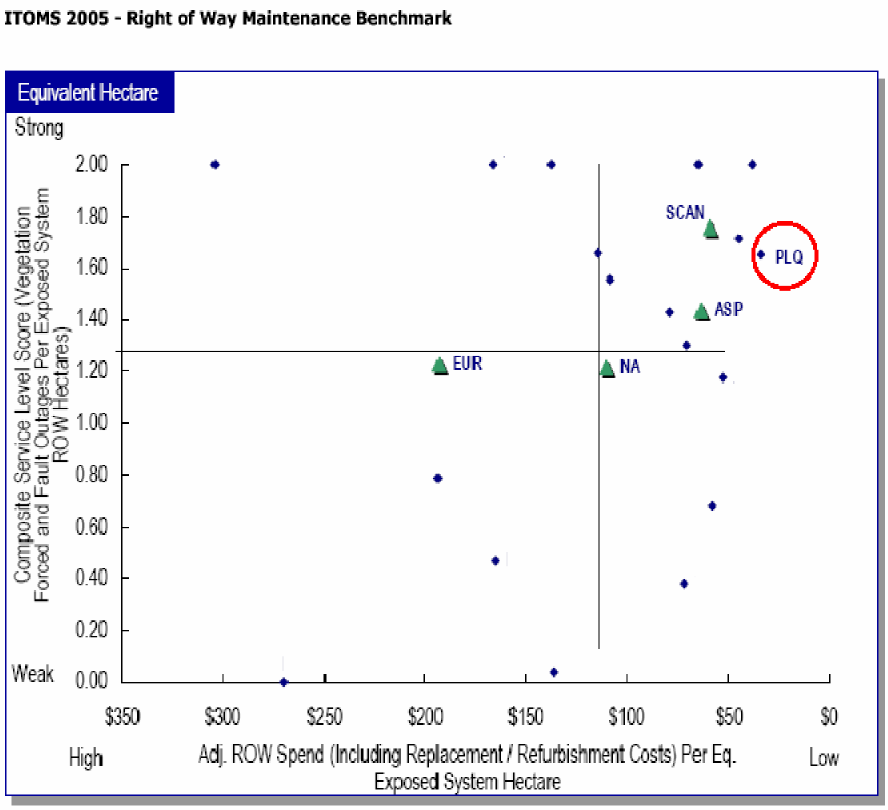
Approximately 80% of Powerlink's easements do not require the more intensive management techniques. The other 20% of easements are either covered by the new Act or are in sensitive locations that require more intense management strategies. It is noted that Powerlink also manages easements located in protected areas, such as areas managed by the Wet Tropics Management Authority (WTMA) where management costs are up to 5 times more than the northern region average. In addition Powerlink advised that the Queensland Parks & Wildlife Services (QPWS) has already written its Code of Practice and it may be more onerous than the WTMA's. Approximately 8% of Powerlink's easements are in areas managed by the QPWS.

We acknowledge that in the initial stages, vegetation management of easements covered by the new policy can be more expensive. However, over time some of these costs should reduce as the removal of unsuitable trees reduces overall growth rates, operators gain more experience in predicting the growth rates of specific species in different locations, and some costs are offset by removal of the need to dispose of substantial amounts of cleared timber. We believe that the total cost impact of the new requirements will not be fully understood until additional experience is obtained.

Another significant change, which is a result of the *Electrical Safety Act* 2002, is an increase in the minimum approach distance to transmission lines from 4.5 metres to 6 metres. This change means that trained linepersons are needed to trim any tree that encroaches closer than 6 metres to a live conductor. This has resulted in increased trimming frequencies and increased work effort to maintain the required 6 metre clearances from live conductors.

We requested additional information from Powerlink regarding its efficiency in vegetation management and the ITOMS Benchmarking chart shown in Figure 5-10 was supplied. This chart details Powerlink's relative efficiency in easement management. This chart indicates that Powerlink is one of the more efficient operators relative to other participants in the benchmarking study. However, the impact of the more labour intensive requirements required under the new vegetation management policy would not be fully factored into these results.

Figure 5-10: Benchmarking of Easement Management Costs



Note: Powerlink shown as PLQ.
Source: Powerlink

A key issue to be considered in predicting future vegetation management expenditure is whether the required work effort will continue to increase from the base year over the remainder of this current regulatory period and throughout the next regulatory period or whether it will increase initially and then stabilise at a higher level. In its opex model, Powerlink has assumed that the vegetation management work effort will increase at 2.5% per annum from the base year through to the end of the next regulatory period. We consider a more probable outcome would be for the work to compound, possibly at a higher level than 2.5% for the three years from the base year and then for the work effort to remain relatively constant for the remainder of the regulatory period. We therefore recommend that the work effort associated with vegetation management be increased by

6% for the 2005/06 year, then 4% for the 2006/07 year, 2% for the 2007/08 year and then 1% for remainder of the next regulatory period. This approach attempts to capture the significant initial increase in effort generated by the new policy but acknowledges that the work effort should reduce over time.

The impact of this recommendation is shown in Table 5.5. In this table the impact of the revised vegetation management escalation factor have been calculated by adjusting the Powerlink opex model but excludes the effect of any adjustment to other escalation factors.

Table 5.5: Impact of Revised Vegetation Management Costs ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink Revenue Proposal	113.11	119.49	126.54	135.64	140.16	634.94
Impact of Revised Vegetation Management	113.47	119.75	126.68	135.63	139.97	635.50
Variation	0.36	0.26	0.14	(0.01)	(0.19)	0.56

Source: PB Associates' analysis

5.5.7 Asset Growth Economies of Scale

In its opex model Powerlink has provided for an overall increase in the maintenance work effort as the asset base grows. However, it has also factored in economies of scale by reducing the impacts of asset growth by the factors shown in Table 5.6. In addition, the total asset base is increased only as new assets are commissioned (rather than as capex is incurred), because there is no impact on maintenance work when assets are still under construction. Whilst Powerlink acknowledges that these economies of scale factors are based on judgement, we agree that, except for the field maintenance factor, they appear reasonable.

Table 5.6: Factors for Economies of Scale

Activity	Scale Factor	Powerlink's Rationale
Field Maintenance	95%	There is almost a one-for-one increase in maintenance effort but some efficiencies should be achievable.
Maintenance Support	25%	Significant economies of scale are possible through efficient management of this activity.
Direct costs.	100%	This covers expenditure such as land rates, where no efficiencies are possible.
Operations	25%	Significant economies of scale are possible through efficient management of this activity.
Asset Management Support	10%	Substantial economies of scale are available and recognised.
Corporate Support	10%	Substantial economies of scale are available and recognised.
Insurance	-	Not applicable as insurance costs are based on a broker estimate.

Source: Powerlink Opex Model

In respect of field maintenance expenditure, while we agree that additional assets have an immediate impact on routine maintenance, and also on the emergency and deferred maintenance effort, we consider that new assets should not impact condition based maintenance expenditure for some time, and certainly not during the same regulatory period in which the assets were commissioned. This view is based on the premise that new assets require inspection, testing, operation and may require emergency maintenance but should not require any condition based maintenance for at least the first five years of service life. We therefore recommend that the condition based maintenance input requirement should remain constant over the regulatory period and that the 95% economy of scale factor should not be applied to this component of field maintenance expenditure.

In order to model this reduced impact, we have made a manual adjustment to Powerlink's opex model so that the level of condition based maintenance remains constant in real terms throughout the next regulatory period. In other words we have maintained the initial level of condition based maintenance throughout the entire regulatory period and not increased it for asset growth. All other maintenance functions, including routine and emergency maintenance, have been increased to reflect the increasing asset base (i.e. newly commissioned assets) and reduced by the Powerlink economy of scale factors. The other components of field maintenance have increased in the Powerlink opex model by a factor of 95% of asset growth, to reflect the almost direct relationship between maintenance effort and asset size. For example the work effort associated with routine and emergency maintenance is almost directly related to the network size and this is reflected by the use of a 95% asset growth economy of scale factor. The impact of the recommended reduction in condition based maintenance expenditure is shown in Table 5.7. In this table the revised expenditure details the impact of reduced condition based maintenance expenditure only and does not include the impact of other adjustments.

Table 5.7: Impact of Revised Condition Based Maintenance Expenditure ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink Revenue Proposal	113.11	119.49	126.54	135.64	140.16	634.94
Impact of Reduced Condition Based Maintenance	112.55	118.34	124.87	133.50	137.46	626.72
Variance	(0.56)	(1.15)	(1.67)	(2.14)	(2.70)	(8.22)

PB Associates' Analysis

5.5.8 Operational Refurbishment

In its Financial Management Practice Manual, Powerlink has included a list of its standard asset categories. These asset categories are set at very high plant levels, for example "Transmission Lines Overhead" and "Transmission Lines Underground". Similar high plant level asset categories are used for substation assets, where a substation bay, including circuit breakers, bus work, structures, isolating and earth switches is the smallest level to which assets are disaggregated. Hence replacement of an item of equipment, such as a circuit breaker, within a substation bay is treated as an operational refurbishment and not capitalised, since it does not involve the replacement of a complete asset in the asset register. This capitalisation practice is not universally implemented throughout the industry. Many network service providers break down their asset base into much smaller asset categories such as protection systems, circuit breakers and isolating switches. TransGrid, for example, considers circuit breaker replacement and protection relay replacements to be capital expenditures and includes them in its capital works programmes.

We therefore consider that many of the more substantial asset replacement and refurbishment projects that are categorised by Powerlink as operational refurbishment should be capitalised rather than expensed. Such replacement programmes extend the service life of the overall asset base and are therefore of a capital nature.

To this end we have reviewed Powerlink's 2005 Network Refurbishment Plan, which forms the basis of its operational refurbishment expenditure forecast, and identified those projects we consider are of a capital nature, and which should therefore be included in the capital budget. Appendix K details which of these projects we consider should be included in the capital works program. The remaining projects, with the exception of several projects which have been removed from this cost category since they are included in vegetation management costs[84], appear to be planned maintenance, consistent with general industry practice. The impact of this adjustment is shown in Table 5.8 and the values have been calculated by converting the nominal project estimates contained in the 2005 Network Operational Refurbishment Plan to real 2006/07 dollars using the CPI assumptions in the Powerlink opex model.

The operational refurbishment expenditure forecast shown in the table has been taken from Powerlink's opex model and has been produced using an algorithm developed by Powerlink. As a result this forecast is slightly different from the costs in Powerlink's 2005 Network Operational Refurbishment Plan. In assessing the capex component of the operational refurbishment forecast we used the estimates in the Network Operational Refurbishment Plan, which reflect the actual works programmed during the next regulatory period.

Table 5.8: Impact of Capitalisation Adjustment to Operational Refurbishment Forecast ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink's forecast Operational Refurbishment	18.73	19.97	20.69	22.67	23.04	105.10
Capex Component	7.29	8.92	10.44	11.14	10.56	48.35

Source: PB Associates' analysis

We recommend that the capex component shown in Table 5.8 be removed from the controllable opex expenditure forecast and included in the asset replacement capex forecast.

5.5.9 Impact of Reliability Centred Maintenance on Maintenance Ratios

Powerlink's opex model predicts the quantity of planned and unplanned preventative maintenance by multiplying the base routine maintenance work units by appropriate ratios. First the quantity of planned routine inspection and testing maintenance for the base year is multiplied by a ratio (R_p) to determine the total quantity of condition based maintenance expected annually for each asset type. The sum of condition based maintenance and routine inspection and testing maintenance is then multiplied by a second ratio (R_c) to determine the total quantities of corrective maintenance expected annually. Finally the corrective maintenance quantities are multiplied by a third ratio (R_e) to determine the expected amount of emergency maintenance for each asset type.

Normally the maintenance ratios would be obtained by analysing historical data to determine the average quantity of maintenance arising from routine inspections and testing. However, as a result of the introduction of RCM the use of historical ratios would result in higher maintenance quantities than would be expected once RCM is fully rolled out.

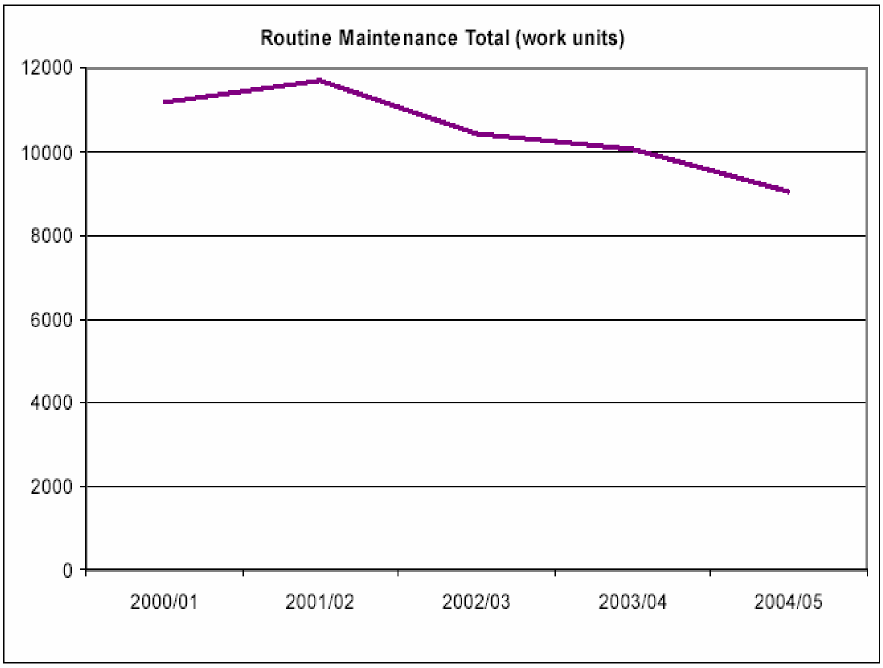
However the roll-out of RCM2 is still not complete so the full impact of this program over the next regulatory period could not be assessed using the 2004/05 base year ratios. Nevertheless, the introduction of RCM2 has already had a significant impact on maintenance requirements as can be seen in Figure 5-11, which shows the reduction in total routine maintenance work units achieved through the implementation of RCM2 from the time of its introduction through until 2004/05.

84 The removal of these costs does not change Powerlink's forecast operational refurbishment costs, which due to a discrepancy in the Powerlink analysis are lower than the total estimated costs of the remaining projects in Powerlink's operational refurbishment plan.

In the absence of meaningful historical data, Powerlink has used its asset management strategists to estimate appropriate modelling ratios based on the individual strategies for the different asset types. These estimated ratios have been used in Powerlink's opex model.

Whilst it has not been possible to review every asset strategy to test the estimated ratios for "reasonableness" we have reviewed the ratios against the actual ratios for the 2003/04 and 2004/05 financial years.

Figure 5-11: Impact of Reliability Centred Maintenance



Source: Powerlink.

Omitting the impact of live substation and Aeropower maintenance where all the maintenance ratios remain constant from the 2004/05 year to the end of the next regulatory period, we note the following changes to the historical maintenance ratios incorporated in Powerlink's opex model:

- The key ratios of R_p for lines and substations were reduced by 4.7% and 18.8% respectively from the average for the 2004/05 year;
- R_p for communications and secondary systems were reduced by 25% and 12.5% respectively from the average for the 2004/05 year;
- All lines ratios are lower with the exception of R_c which is 18% higher than the average for the 2004/05 year;
- All substation and secondary systems ratios are lower than the average for the 2004/05 year
- R_p for communications is 25% lower but R_c and R_e are 6% and 15.4% higher than the average for the 2004/05 financial year.

As discussed above the ratios going forward have been determined by the asset management strategists for specific asset categories based on actual performance and their view of future performance. While a few ratios have been increased above the historical levels these increases have been offset by the much more significant impact of the decreases in the other ratios. The resultant effect is a continuation of the current downward trend of the reduction in total work units as a result of the introduction of RCM2. This impact has been factored into the opex model. In the absence of meaningful historical data we believe the approach taken by Powerlink to be reasonable and do not recommend any further adjustments.

At the 2012 revenue cap reset Powerlink should have access to seven years of historical data, which will reflect the full effect of RCM. This should enable a much more accurate determination of the various ratios based on historical performance.

5.5.10 Efficiency of Work Unit Costs

Since all Powerlink's maintenance work in the northern and central regions is done by Ergon Energy under the SLA, it is not possible to examine open tender information to determine the efficiency of the work unit costs included in the agreement. Furthermore, comparative Queensland data is difficult to obtain due to the lack of alternative service providers in rural and regional Queensland. In addition, the use of work units, rather than the more standard labour, plant and material schedule of rates, in the SLA makes it difficult to compare costs at this level.

We have therefore relied on a comparison of the work unit costs of Powerlink's internal and external service providers to assess cost efficiency and reasonableness. Generally, for the common work units including communications, lines, substations and secondary systems, Powerlink's internal service provider's costs compare favourably with Ergon Energy's costs in the central region. The costs in the northern region are higher due to the larger distances between Powerlink's assets and the depot incurring additional travelling time and accommodation costs.

Since Aeropower is the only provider of aerial maintenance services in Australia, competitive tender prices are not available to determine the efficiency of the costs in this agreement. However, Powerlink has advised that generally costs for helicopter maintenance and patrol services are similar to the cost of providing these services by ground staff and helicopter services have the key advantage of faster service provision. The Aeropower contract is a schedule of rates contract and Powerlink benchmarks service costs against the costs of providing these services by using local ground staff.

In addition, the benchmarking discussed in Section 5.3.2 indicates that Powerlink's current expenditures appear efficient relative to other TNSPs both in Australia and overseas. On balance we consider that Powerlink's current work unit costs are reasonable. This view is based on both the current absolute cost of the work units and on Powerlink's operational efficiency when benchmarked against other TNSPs.

5.5.11 Capex/Opex Trade Off

Powerlink has addressed this issue in its opex model by reducing the total annual growth in asset value by the amount of its forecast asset replacement expenditure each year before it applies the factors for asset growth escalation factors. The methodology involves the conversion of all asset values to 2004/05 dollars, determining the growth in the value of each asset category over the next regulatory period, and then reducing the growth in asset value for each asset category by a percentage that represented the average proportion applicable to asset replacement. Powerlink determined the average percentage reduction for each asset category that related to asset replacement by costing each job in their projected 5 year asset replacement plan.

This approach ensures that only new assets are allowed for when applying the asset growth escalation factors shown in Table 5.6.

5.5.12 Insurance

The insurance costs provided for in Powerlink's Revenue Proposal are shown in Table 5.9. The two components are discussed separately below.

Table 5.9: Insurance Costs ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12
Insurance Premiums	3.67	3.82	3.99	4.15	4.29
Self Insurance	1.26	1.28	1.30	1.30	1.31

Source: Powerlink Revenue Proposal – Tables 7.6 and 7.7.

Insurance Premiums

The insurance premiums provided in Powerlink's Revenue Proposal are based on a forecast produced by its insurance broker and include an annual provision for a risk review survey to be carried out each year. The broker forecasts cover the five years from 2006/07 and hence Powerlink has projected these assumptions to determine a forecast premium for the final year of the regulatory period. This appears reasonable as the forecast pattern used by the broker is evident from its report.

We reviewed the broker's report and the underlying assumptions incorporated into its projections. Generally these assumptions appear reasonable. Nevertheless we requested additional information from the broker in relation to the escalators used to calculate future premiums, which have been projected from the 2005/06 actual premiums[85].

The major components of each annual premium are public liability and industrial special risks, which together constitute approximately 87% of Powerlink's total annual premium. These two insurance premium components were escalated by 7.5% per annum except for the second year (2007/08) when they were escalated by 10%. The broker has advised that the power and utility industry is unique and hence only attracts a limited number of insurers willing to write this type of business.

The broker expects to see an increase in premium rates in both industrial special risks and public liability as the insurers incurred major losses in 2005 due to claims worldwide and also because of two substantial outstanding Powerlink special risk claims which, if accepted, will have a material impact on Powerlink's premiums. The extent of any further increase will be dependent on world wide utility/energy losses incurred in 2006. In addition, Powerlink's increasing asset base impacts on the level of future premiums.

On balance, we consider that the projected insurance premiums included in the Powerlink Revenue Proposal are reasonable.

Self Insurance

The self insurance forecast includes the estimated annual cost of losses relating to uninsured losses and uninsurable risks. Uninsured losses include insurance policy excesses and uninsurable risks refer to situations where no insurance is available such as for transmission lines. Whilst insurance was obtained for industrial special risks, machinery breakdown has been included in the self insurance costs as the base premium quotes and deductible terms for this item resulted in the insurance being very costly for the limited cover provided.

85 The reason for requesting this additional information was that the ACCC's fourth Monitoring Report on Public Liability and Professional Indemnity insurance dated January 2005 states, in relation to public liability that "The real average premium fell by 15% between year ending 31 December 2003 and half year ending 30 June 2004, reversing the trend of substantial increases since 2000 (P16)."

Powerlink engaged an actuarial consultant to prepare an estimate of the annual costs for losses relating to uninsured losses and uninsurable risks. They prepared annual estimates based on the mid point of a range of possible outcomes, and also included an allowance for the projected growth of the Powerlink network. We have reviewed the methodology, source information and data used by the actuary and consider the analysis to be reasonable.

5.5.13 Allocation between Regulated and Non-Regulated Businesses.

Powerlink uses its overhead allocation process to ensure the appropriate allocation of costs between the regulated and unregulated components of its business. All overheads, including direct, indirect, and plant and vehicle operation and depreciation costs are incorporated into labour rates on a full cost recovery basis. Direct costs relate to annual leave, sick leave etc whilst indirect costs include costs such as facilities and plant depreciation allowances, information technology support, corporate support and human resources support.

In regard to facilities and plant or vehicle costs Powerlink has advised that the allocation to labour on-costs includes operational costs and depreciation but does not include any return on the capital component. The depreciation allowance is debited against corporate costs so that, as corporate costs are allocated to either regulated or unregulated works, the depreciation costs attributable to the non regulated works are recovered externally and regulated depreciation costs recovered internally. The depreciated value of these items is included in the RAB on an avoidable cost basis since, on average, 94% of Powerlink's business activities are regulated. This means that all the return on capital is recovered from the regulated business.

The burdened labour rate is allocated to either regulated or unregulated jobs or projects via timesheets to ensure that all labour and overhead costs are appropriately allocated. Material costs are directly allocated to individual jobs or projects. No internal profits are generated from internal charges. The process is well entrenched in Powerlink and has been in operation for many years.

We consider that the cost allocation between the regulated and non-regulated businesses is well controlled within the business. The process is mature, robust and auditable.

5.6 OTHER OPERATIONAL EXPENDITURE

5.6.1 Grid Support

Grid support is a non-network solution used by a TNSP as a cost effective alternative to network augmentation. The regulatory test requires TNSPs to identify and evaluate both network and non-network solutions for emerging network constraints. Powerlink has included the grid support forecast expenditure shown in Table 5.10 to provide for the two grid constraint situations described in its Revenue Proposal. These two situations are described further below.

Table 5.10: Powerlink’s Proposed Grid Support Costs ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12
Grid Support	24.03	17.34	22.15	8.22	8.30

Source: Powerlink Revenue Proposal – Table 7.9

North Queensland

As noted in Powerlink’s Revenue Proposal, the supply to North Queensland is characterised by long transmission distances. This favours the economics of non-network solutions compared to major transmission augmentations. Grid support to North Queensland is the largest component of the grid support expenditure forecast (approximately 80%) and the most difficult to forecast accurately. Grid support contracts are already in place for North Queensland and Powerlink expects that additional contracts will be signed over the next regulatory period.

Powerlink developed a simulation model to estimate its North Queensland grid support requirements and associated costs. The model is based on the current contracts Powerlink has in place for grid support services. In estimating its grid support requirements Powerlink has factored in the impact of future network augmentations planned during the next control period.

The inputs for the model are:

(i) forecast demand for each half hour period of the year for a number of outlooks including high, medium and low economic growth and 50%, 10% and 90% PoE demand and energy. This provides nine different patterns for each year of the next regulatory period;

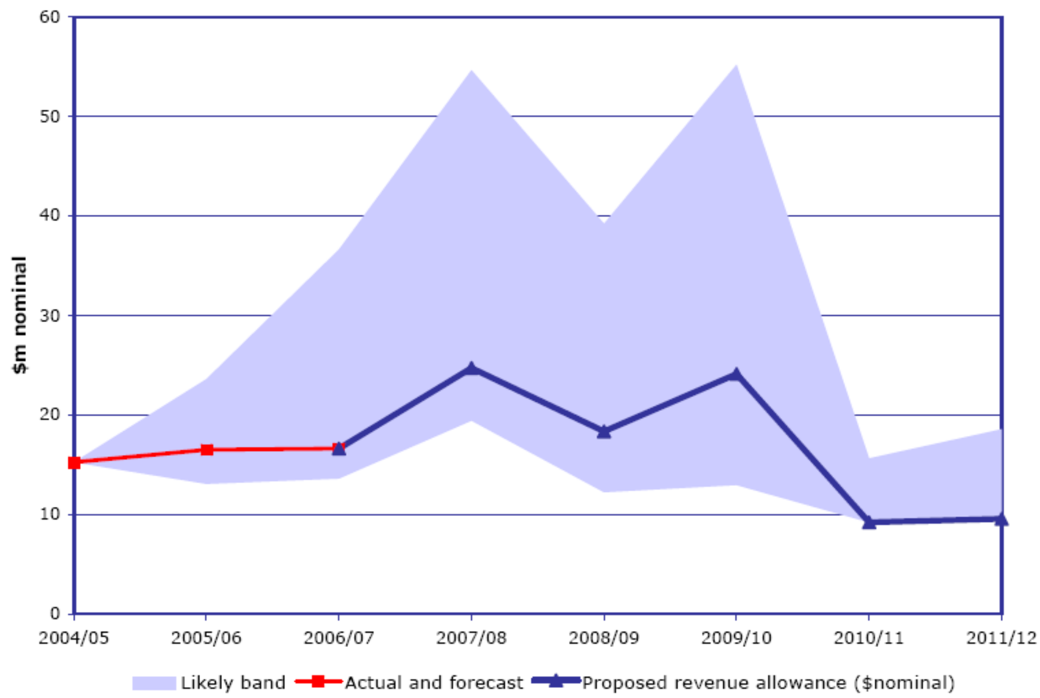
(ii) transmission network capability;

(iii) hydro generator outputs at Barron Gorge and Kareeya; and

(iv) output from other generators.

A total of 648 unique combinations are available for each year. Each of these combinations was modelled to determine the associated grid support costs. The output of this modelling provided a range of possible grid support costs as shown in Figure 5-12 where the dark blue line shows the provision for grid support costs included in the Revenue Proposal. This is based on average conditions, i.e. medium economic growth, 50% PoE demand and average hydro generation. The high and low demand growth outlooks are outside the bounds shown in the figure.

Figure 5-12: Actual and Forecast Grid Support Costs



Source: Powerlink Revenue Proposal – Figure 7.10

South East Queensland Reactive Power

In South East Queensland significant amounts of reactive power are required to maintain stable transmission voltages during times of peak demand. The majority of this reactive power is supplied by capacitors and static reactive power compensators and a small amount is provided by generators. NEMMCO currently contracts for reactive power from several generating units in South East Queensland. These contracts cover the provision of reactive power in excess of the generators' registered performance but they expire on 30 June 2007.

Powerlink is currently negotiating with local generators for continued provision of this reactive support. However, a fall back position would be the installation of additional reactive support within their network.

The reason Powerlink has included this reactive support in its Revenue Proposal is that NEMMCO has decided to standardise its approach to providing reactive support throughout the NEM, allowing market participants to negotiate appropriate long term contracts for the provision of reactive support. Current NEMMCO contracts have only a two-year duration and Powerlink can consider longer term contracts or alternate reactive support options.

General Comments

In its Revenue Proposal, Powerlink proposes that "its grid support forecast be included as an additional element of operating expenditure, with a pass through arrangement to manage differences (both "unders" and "overs") between the allowance and actual grid support expenditure". As discussed above, there is considerable variability in potential grid support requirements for North Queensland and some uncertainty relating to grid support for South East Queensland. We agree that the implementation of a pass through arrangement would help manage this uncertainty. Depending on actual conditions the maximum grid support costs could be significantly higher than the average grid support forecasts included in its Revenue Proposal.

We consider that the methodology used by Powerlink to predict the grid support requirements in North Queensland and South East Queensland is sound and the resultant range of possible outcomes reasonable. As discussed above the significant variability in actual grid support costs needs to be managed and we would support the introduction of a pass through arrangement to help manage this uncertainty.

5.6.2 Capex Efficiencies

In its Revenue Proposal, Powerlink has included a provision for capex efficiencies as a component of "other opex" expenditure. As the 2001 Powerlink Revenue Decision included a carryover allowance of $8.2 million to be included in the next regulatory period we have only reviewed the Gold Coast Supply capex efficiency claim as detailed in Table 5.11.

Table 5.11: Capital Efficiencies in Powerlink's Opex Proposal ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12
Gold Coast Supply	4.85	4.85	4.85	4.85	4.85

Source: Powerlink Revenue Proposal – Figure 7.10

The capex efficiency claim relates to claimed cost efficiencies achieved on the Gold Coast Reinforcement Project. Powerlink considers that its management actions resulted in capital expenditure savings on this project, and proposes that the gains be shared equally with its customers over the next regulatory period.

Powerlink argues that it acquired the easements for the project at a cost that is significantly lower than it would have paid had the easements been acquired immediately prior to construction commencing. It also states that it maintained the right for construction to proceed, even though this process still required a persistent and directed effort with local government bodies, the community, individual property owners and purchasers. Powerlink further argues that its actions, in obtaining the easements earlier than required and maintaining its right to construct a power line on them, resulted in considerable savings compared to the cost it would have incurred by waiting until the time of construction before obtaining the required easements and consents.

The Gold Coast reinforcement project involved two stages. The first stage was undertaken in 2003 and involved the construction of a tee line between Maudsland and Molendinar. Stage 2 involves the construction of a double circuit 275 kV line between the new substation at Greenbank and Maudsland which is due to be commissioned in October 2006. Easements for all these works were acquired in the late 1980s.

To determine the magnitude of the claimed capital efficiencies Powerlink engaged an independent consultant to evaluate the costs to establish a corridor for these new works and associated construction costs in a 2005 environment, assuming that the required easements had not already been procured.

The claimed capital efficiency is essentially the difference between the actual easement procurement costs and the consultant's estimate of the costs that would have been incurred if the easements had been procured immediately prior to construction. Powerlink considers that its action in procuring the easements in the 1980s represents either management efficiencies or innovation as described in the DRP. However Powerlink is quoted in the consultant's report as having a policy to acquire land and transmission line easements where it is identified that future augmentation of the transmission network will be required in order to satisfy its reliability of supply obligations.

It is common practice within the industry for both TNSPs and DNSPs to acquire strategic easements and land for future assets well in advance of construction occurring, and Powerlink are quoted as having a similar policy. Typically, long term planning identifies areas where either additional assets or system augmentation will be required, and land or easements are acquired once the requirement has been identified where it is believed that delaying the purchase may result in the asset not being available when required or being significantly more expensive to acquire. This often occurs as a consequence of changes in land use.

We therefore consider that the acquisition of the easements in the 1980s for augmentation of supply to an obvious growth area such as the Gold Coast, in an obvious growth corridor is consistent with accepted and good electricity industry practice in Australia and any savings in costs due to the early acquisition should not be attributed to a particular management efficiency or innovation.

We also note that the easements concerned have been included in Powerlink's RAB since they were acquired and have been receiving an appropriate return on the capital invested over that time.

We therefore consider that the capital efficiencies claimed by Powerlink for the Gold Coast supply should not be included in opex forecasts for the next regulatory period.

5.7 RECOMMENDATION

The combined impact of our recommended changes to Powerlink's controllable opex forecast is shown in Table 5.12. All amounts are shown in 2006/07 dollars.

Table 5.12: Recommended Opex Forecast ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Powerlink's Forecast Controllable Opex	113,106,606	119,488,880	126,540,382	135,641,287	140,158,649	634,935,804
Changes to Labour, Material and Vegetation Management Costs	15,802	(237,696)	(523,008)	(1,808,464)	(3,187,621)	(5,740,987)
Change to Operational Refurbishment Costs	(7,288,000)	(8,922,000)	(10,443,000)	(11,135,000)	(10,563,000)	(48,351,000)
Changes to Condition Based Maintenance.	(543,502)	(1,119,274)	(1,619,197)	(2,031,255)	(2,527,416)	(7,840,644)
Recommended Controllable Opex Forecast	**105,290,906**	**109,209,910**	**113,955,177**	**120,666,568**	**123,880,612**	**573,003,173**

Source: PB Associates

The total effect of our recommended changes is a reduction of $61.93 million (06/07) in forecast opex over the five year regulatory period. If these recommendations are adopted, however, the capital budget would have to be increased by a total of $48.35 million (06/07) which is the component of operational refurbishment which we consider to be of a capital nature. This amount should be added to Powerlink's capex forecast in accordance with the schedule in Table 5.13. The values in Table 5.14 have been calculated by converting the individual project estimates detailed in the 2005 Network Operational Refurbishment Plan into real 2006/07 dollars using the CPI projections contained in the Powerlink opex model.

Our recommended controllable opex shown in Table 5.12 equates to an average annual expenditure of $114.60 million. This compares to a projected average annual controllable opex of $93.26 million over the current regulatory period. In its Revenue Proposal, Powerlink's proposed annual controllable opex was $126.99 million. Our recommended average annual controllable opex represents an increase of 23% compared to the current regulatory period, whereas the Powerlink Proposal represents an increase of 36%. Over the same period the RAB will increase by 30%. All values are expressed in 2006/07 dollars.

Table 5.13: Capex Component of Forecast Operational Refurbishment ($m, 06/07)

Item	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Total	7,288,000	8,922,000	10,443,000	11,135,000	10,563,000	48,350,000

Source: PB Associates

5.8 EFFICIENCY OF FORECAST OPERATIONAL EXPENDITURE

Table 5.14 shows the percentage of our recommended forecast opex to Powerlink's forecast closing RAB but does not include any increase in capital works as a result of transferring the operational refurbishment works of a capital nature into the capital budget. The closing value of RAB is based on the capital works program included in the Powerlink Revenue Proposal and hence any alterations to this capital works program would impact on these results. For example, reductions in the projected capitalisations would increase the opex to RAB ratios, while increases would reduce the ratios.

We acknowledge that these percentages are not an absolute measure of relative efficiency, but they do provide some insight into operating efficiency. The ratios indicate that PB Associates forecast operational expenditures for Powerlink represent efficient levels of operational expenditure relative to the other TNSPs operating in the NEM.

Table 5.14: Opex/RAB Ratio for Recommended Opex ($m, nominal)

Item	2007/08	2008/09	2009/10	2010/11	2011/12
Closing RAB	4,344.1	4,877.7	5,348.0	5,843.3	6,317.1
Recommended Opex	108.34	115.62	124.23	135.32	143.04
Ratio of Opex/RAB	2.50%	2.37%	2.32%	2.32%	2.26%

6. SERVICE STANDARDS

6.1 INTRODUCTION

Establishing standards of service is an important aspect of Powerlink's Revenue Proposal. Incentive-based regulation is designed to provide incentives for businesses to achieve efficiencies in the provision of services by allowing them to retain any savings in the cost of service provision within the 5-year regulatory period. However, in order to ensure that any reductions in expenditure are due to genuine efficiencies and do not result in a deteriorating level of service, the AER and regulators in other jurisdictions have recognised the importance of clearly specifying target standards of service, and then monitoring actual service levels against these targets. In this way businesses are held accountable for the service levels they deliver.

The objective of this review is to recommend an appropriate performance incentive scheme for Powerlink.

6.2 PRINCIPLES FOR ESTABLISHING A SERVICE INCENTIVE SCHEME

6.2.1 Service Standards Guidelines Requirements

In 2003, the ACCC[86] released a decision[87] accepting the recommendations of a report by Sinclair Knight Merz (SKM)[88] about the service standards that may apply to TNSPs. The SKM recommendations included performance measures and targets that it considered appropriate for Powerlink. In its Service Standards Guidelines (SSG), the ACCC indicated that it may consider alternative performance measures or targets as proposed by TNSPs in their revenue proposals. [89]

Through its adoption of the SSG, the AER has stated that service performance should be linked to regulated revenues through a performance incentive scheme that provides incentives for TNSPs to improve performance against the defined performance measures by rewarding them when performance standards increase, and penalising them when performance standards decline. It is therefore important that the targets for those performance measures that are to be included in the performance incentive scheme are based on robust and repeatable data.

The SSG set out the treatment of service standards in each TNSP's revenue cap decision as well as the information that a TNSP must provide in its revenue proposal and annual reporting requirements. Key elements of the SSG are that:

- the AER will include a performance incentive component in each revenue cap decision;
- where possible, the AER will use the TNSP's performance history to set performance targets;
- the performance measures will include:
  - circuit availability;
  - average outage duration;

[86] ACCC was the relevant regulator of transmission services in Queensland in 2003.

[87] ACCC, 2003, *Statement of Principles for the Regulation of Transmission Revenues, Service Standards Guidelines, Decision*

[88] SKM, 2003, *Transmission Network Service Provider (TNSP) – Service Standards, Final Report*.

[89] Ibid p.1

  - frequency of ‘off-supply’ events; and
  - inter-regional and intra-regional constraints (not currently utilised).
- the TNSP must report its performance for, at least, the three years before its revenue cap application; and
- a TNSP may request that the AER include additional or amended performance measures when it makes its revenue cap decision.[90]

The SSG were supported by an ACCC Decision[91] that set out the individual definitions for the performance measures that would apply to Powerlink, including that:

- circuit availability would be measured for three sub-measures: critical circuits; non-critical circuits; and peak periods and would apply to all lines, transformers and reactive devices;
- a loss of supply events frequency index would be implemented according to the standard definition provided in the SSG;
- average outage duration would be for unplanned outages only on lines, transformers and reactive devices and the effect of any single event would be capped at seven days; and
- intra and inter-regional constraint data was not available and a working group would be established to progress development of these measures before they would be applied.

6.2.2 Principles for Setting Service Standards

In its Revenue Proposal, Powerlink sets out principles for setting service standards, stating that they should:

- only apply to indicators within Powerlink’s control or which Powerlink is best placed to manage, and conversely, standards should not be set based on indicators that are outside of Powerlink’s control;
- be consistent with planning and network development standards;
- not impose a “one size fits all” approach on Powerlink as there are significant differences in responsibility, operating environment, etc. between TNSPs;
- be consistent with standards and criteria set for operation of the network. Specifically, Powerlink cannot be expected to achieve a standard which exceeds the criteria used by NEMMCO to operate the power system in accordance with National Electricity Law; and
- be consistent with the capex and opex allowed by the AER.[92]

Powerlink states that its network is significantly different to that of other TNSPs, so that direct comparisons between other TNSP’s performance and Powerlink’s performance are inappropriate. Powerlink outlined the differences in its Revenue Proposal.

In undertaking this review we have also taken account of the following additional principles underpinning the design of a good service incentive scheme.

- Targets for indicators that are to be included in the performance incentive scheme should be based on robust historical data. This will ensure that initial targets are appropriate and reduce the risk of an initial windfall gain or loss.

90 Ibid.
91 ACCC, 2003, *Service Standards Guidelines Decision*, Appendix A
92 Ibid p. 129

- The scheme should be revenue neutral for no change in underlying performance. This will ensure that the scheme is fair to both electricity customers and to Powerlink.
- Definitions, data collection and other attributes of the scheme must be robust and repeatable. This will ensure that valid comparisons can be made over the appropriate time period.

6.3 POWERLINK'S REVENUE PROPOSAL

Powerlink states that the performance measures and targets put forward in its Revenue Proposal were developed in accordance with the SSG. Powerlink has not proposed any new performance measures from those proposed in the SSG. Nor has Powerlink proposed any changes over the next regulatory period from the performance targets currently being applied.

The performance measures proposed by Powerlink to be included in its performance incentive scheme for the next regulatory period are:

- transmission circuit availability;
- frequency of off-supply events; and
- average outage duration.

Powerlink's proposed targets and weightings for each of the above indicators are set out in Table 6.1. These are identical to those recommended by SKM in 2003. Definitions for the terms used in the performance measures can be found in Appendix L.

Table 6.1: Powerlink's Proposed Measures, Targets and Weightings

Measure	Unit	Proposed Target	Proposed Weighting %
Circuit Availability – critical	%	97.15	15.5
Circuit Availability – non-critical	%	97.98	8.5
Circuit Availability – peak	%	97.45	15.5
Loss of supply events > 0.2 system minutes	number	4	15.5
Loss of supply events > 1.0 system minutes	number	1	30.0
Average Outage Duration – capped 7 days	minutes	800	15.0

Source: Powerlink Proposal – Table 11.4

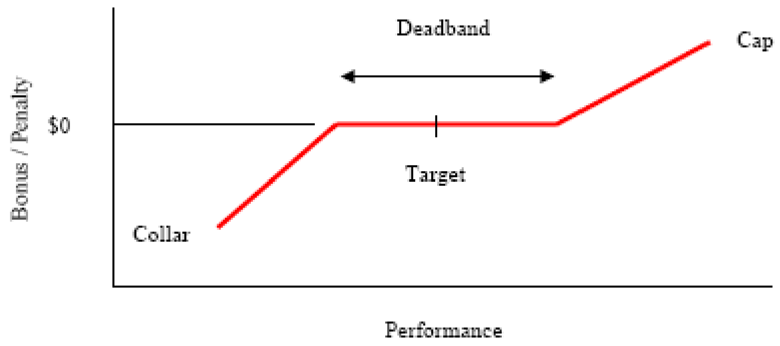
While the Revenue Proposal does not provide detailed reasons for adopting the proposed performance measures or targets, from our discussions with Powerlink on its proposed performance incentive scheme we understand that:

- Powerlink has not changed the performance measure targets proposed by SKM given the more recent data available for 2002, 2003, 2004 and 2005.
- Powerlink considers that the targets proposed by SKM incorporate the perceived impact of planned outages required to implement Powerlink's large capex program and the long thin nature of the network.

The performance incentive scheme proposed by Powerlink includes caps and collars that limit the amount of revenue at risk to 1% of the MAR. The caps and collars proposed by Powerlink are expressed as a weighting for each measure such that if actual performance exceeds the cap/collar, the cumulative value of the weightings place a maximum of 1% of revenue at risk for poor performance and provide for a maximum 1% bonus for out-performing the targets. Four of the six proposed measures contain caps and collars that are not symmetrical in that the rate at which the reward accrues is different (quicker) than the rate at which the penalty accrues.

The proposed performance incentive scheme also includes target dead-bands for two measures—loss of supply events and average outage duration. These dead-bands define when a reward or penalty will start. This arrangement is illustrated in Figure 6-1.

Figure 6-1: Application of Dead-Bands



Collars, caps and dead-bands did not form part of the recommendations made by SKM. Nevertheless the model developed by SKM as a basis for discussion about the suitability of the measures included these items. Powerlink has proposed the same collars, caps and dead-bands for each of the measures as contained in the SKM model, as shown in Table 6.2.

Powerlink does not provide any detailed reasons for adopting these collars, caps and dead-bands.

Table 6.2: Powerlink's Proposed Service Standard Measures

Measure	Unit	Weighting %	Max Penalty	Start Penalty	Target	Start Bonus	Max Bonus
Availability – critical elements	%	15.5	96.55	97.15	97.15	97.15	97.65
Availability - non-critical elements	%	8.5	96.33	97.98	97.98	97.98	98.33
Availability - peak hours	%	15.5	96.65	97.45	97.45	97.45	98.15
Loss of supply > 0.2 system minutes[1]	number	15.5	6	4	4	3	1
Loss of supply > 1.0 system minutes	number	30.0	3	2	1	1	0
Average outage duration (capped 7 days)[2]	minutes	15.0	1200	800	800	700	300

Source: Powerlink Revenue Proposal - Table 11.4
Note 1: Measurement of system minutes is described in Section 6.6.2
Note 2: Measurement of outage duration is described in Section 6.6.3.

6.4 PB ASSOCIATES' APPROACH TO THE REVIEW

In undertaking this review we have:

- assessed the suitability of the proposed performance measures for inclusion in Powerlink's performance incentive scheme;

- reviewed the rationale behind Powerlink's proposed targets, weightings, collars, caps and the use of dead-bands; and
- recommended service standard targets to be included in Powerlink's performance incentive scheme.

To inform the review, we have examined the following aspects of the proposed performance incentive scheme:

- robustness of data definitions;
- soundness of the process for data collection and reporting;
- confidence in the accuracy of historical data;
- appropriateness of exclusions in historical data;[93]
- performance measure calculation; and
- reasons for not proposing other measures.

We also asked for, and received, the following information from Powerlink:

- historical performance data for the proposed measures;
- a list of events excluded by Powerlink from the historical performance data (for 2003, 2004 and 2005);
- information about each of the loss of supply events that exceeded the thresholds of 0.2 and 1.0 system minutes (for 2002, 2003, 2004 and 2005);
- information about the three largest events included in the performance data in the period 2002 to 2004 for each of the Transmission Circuit Availability measures (critical, non-critical and peak);
- information about the 15 longest duration events included in the performance data in the 2005 year for the average outage duration measure;
- relevant data collection and reporting procedures and a copy of the model used by SKM in developing their recommendations for a performance incentive scheme for Powerlink;
- a statement as to whether the proposed increase in capex has been factored into the portion of the target attributed to new works and how this has been done; and
- a list of equipment that is included in the definition of a circuit as used in the measure Transmission Circuit Availability.[94]

6.5 DESIGN OF THE PERFORMANCE INCENTIVE SCHEME

In this section we discuss issues related to the design of a performance incentive scheme for the next regulatory period.

6.5.1 Selection of Performance Measures

Powerlink has proposed the performance measures recommended by SKM in 2003. Data for these measures has been collected for the period 2002 to 2005.

Since performance measures should be based on robust data and noting that Powerlink has not proposed alternative measures or collected alternative data on which alternative

[93] The SSG allow that certain events may be excluded from the performance measures, including force majeure and events caused by third parties. PB Associates has ensured that appropriate events have been excluded from the historical data on which targets for the next regula period have been based.

[94] ACCC, 2003, *Service Standards Guidelines*, p. 4.

measures could be based, we do not see any reason not to accept Powerlink's proposal to adopt the SKM recommended performance measures.

The AER recently released its final decision *Indicators of the market impact of transmission congestion* and first report for 2003–04 of the same title. Reports with the results for 2004–05 and 2005–06 are due to be released by the AER in the third quarter of 2006. We understand that the AER intends to begin a public consultation process to establish a market-based incentive scheme in early 2007 once the Australian Energy Market Commission (AEMC) has released its final decision on the review of chapter 6 of the National Electricity Rules. While the indicators of the market impact of transmission congestion are primarily based on information available from market information systems, we recommend that the AER include in its decision a requirement for Powerlink to collect any data that might be required to support such indicators.

6.5.2 Selection of Weightings for each Performance Measure

The weightings proposed by Powerlink for each of the performance measures are the same as those recommended by SKM. Although SKM did not include reasons for recommending the proposed weightings, it appears that they were based on the perceived value of the measure to customers, that is, frequency of off-supply events greater than 1.0 system minutes weighted highest (30%), critical and peak circuit availability, frequency of off-supply events greater than 0.2 system minutes and average outage duration weighted approximately equally (15 to 15.5% each), and non-critical circuit availability weighted lowest (8.5%). These weightings seem appropriate and we are unaware of any material changes that have occurred which would affect the selection of the weightings

6.6 DEFINITIONS

Robust definitions for each of the performance measures are essential for repeatable outcomes. While the SSG address most definitional issues, the ACCC Decision noted that definitions need to be flexible and align with the information the TNSP has been collecting in the past.[95]

In this section we discuss the specific definitions to be applied to Powerlink's performance measures. A complete definition for each performance measure is provided in Appendix L.

6.6.1 Circuit Availability Measures

Powerlink has proposed three circuit availability measures: (i) outages to critical circuit elements; (ii) outages to non-critical circuit elements; and (iii) outages to circuit elements during peak periods. Powerlink defines these terms as follows:

- A circuit element is an item of primary transmission equipment including a line, transformer, bus or line reactor, capacitor or voltage regulator but does not include individual circuit breakers and isolators. It also does not include secondary transmission equipment such as protection equipment.
- A critical circuit element is defined as an element of the 330 kV network, the 275 kV interconnected network that forms the backbone of the transmission system and of interconnections to other jurisdictions. Other elements are classified as non-critical.[96]
- A peak period is defined as being between 7 am and 10 pm on a weekday, excluding public holidays. All other times are classified off-peak.

95 ACCC, 2003, *Service Standards Guidelines Decision,* p.6

96 Powerlink has provided an excel spreadsheet to PB Associates listing each individual circuit element and its classification. The spreadsheet shows that all 330 kV network elements and most of the 275 kV network elements are classified as critical.

These definitions are consistent with the TNSP-specific definitions set out in the ACCC Decision, except for the exclusion of public holidays from the definition of peak period.[97] PB Associates accepts the clarification of the treatment of public holidays and has included this as an amendment to the definitions (see Appendix L).

Powerlink also clarified that if its equipment is the cause of an incident that affects primary plant or equipment owned by a distributor, a connected customer or a generator then that incident is captured in its annual performance data; despite the fact that the circuit element affected is not owned by Powerlink. This is important because not being owned by Powerlink, the circuit element affected is not included in the total count of circuit hours per year as used in the calculation of the denominator of the circuit availability measures.

For example, if a Powerlink protection scheme mal-operates to open 110 kV circuit breakers that results in a loss of 110 kV lines owned by a distributor. Powerlink would count this incident as a loss of a circuit element, despite the fact that, in this example, the item of primary plant interrupted is a circuit breaker (which is not in itself counted as a separate circuit element) and a line (which is not a Powerlink asset).

We believe that Powerlink's approach is sound where it applies to assets owned by them, that is, where a protection mal-operation results in the opening of a Powerlink owned circuit breaker and, hence, interrupting the delivery of service to its customers. Such incidents should be counted regardless of Powerlink's definition of a circuit element.

Conversely, if the circuit breaker affected is not owned by Powerlink, then the incident should not be counted. This is because no primary asset owned by Powerlink has been affected. The performance incentive scheme does not extend to secondary assets, such as protection schemes. As a result, if no primary asset of Powerlink is affected, then the impact cannot be included in service performance measures that measure the performance of Powerlink's primary plant and equipment.

This approach of limiting the performance incentive measure to primary plant and equipment owned by Powerlink provides for a robust and readily auditable measure. It also means that some customer outages caused by Powerlink's secondary systems at the customer interface are not subject to the performance incentive scheme. These outages, however, occur infrequently and performance of plant and equipment at the customer interface is able to be agreed through connection agreements between Powerlink and its customers.

The application of these definitional issues is further discussed in Section 6.7.

6.6.2 Loss of supply event frequency index measures

Powerlink has proposed two loss of supply event frequency measures: (i) events exceeding 0.2 system minutes and (ii) events exceeding 1.0 system minutes. These measures are inclusive so that, all events that exceed the threshold of 1.0 system minutes are counted in both measures.

The measures are determined by assigning each outage of a circuit element to the event that led directly to the outage. The number of events that exceeded the time threshold is then counted.

Powerlink calculates the system minutes associated with an event as the customer outage duration (in minutes) multiplied by the load lost (in megawatts) divided by the highest system maximum demand (in megawatts) that has occurred prior to the time of the event. For example, an outage of 100 minutes duration that interrupted 30 MW of customer load at a time when the highest system maximum demand on record was 7,900

[97] Ibid, p. 17-18.

MW would be assigned 0.380 system minutes (100x30/7,900). The SSG do not include a definition for system minutes, however, we understand that the methodology used by Powerlink to calculate this measure is consistent with that developed by SKM.

6.6.3 Average Outage Duration Measure

Powerlink determines the average outage duration measure by assigning a duration to each individual circuit element outage. As discussed in the above section, outages of circuit elements are grouped by event. The duration of each event is determined by taking the difference between the time at which the first circuit element was interrupted and the time that the last circuit element was restored to service. The outage duration of each event is then capped at 7 days (10,080 minutes). Capping has the affect of limiting the contribution of any one event to the measure. The proposed cap of 7 days is the same as recommended by SKM in 2003 for Powerlink and is consistent with revenue decisions made since the SSG were adopted.[98]

The average outage duration time of all events is then calculated as the sum of the event outage durations (with each event capped at 7 days) divided by the number of outage events.

6.7 DATA COLLECTION AND REPORTING

Given that data is to be used in a performance incentive scheme, data collection and reporting must be based on robust and repeatable processes. This will ensure that valid comparisons can be made over the appropriate time period. We have examined Powerlink's current data collection and reporting processes, which will also form the basis of future reporting to AER in accordance with the SSG, and find that:

- Powerlink maintains a forced outage database (FOD) and a planned outage database (OSTRAC) that together record all outages on Powerlink's network. The databases also record outages on those parts of the distributors' networks that are under Powerlink's operational control;
- forced outage on/off times are manually input to FOD from time stamped SCADA data recorded in the energy management system (EMS). Autorecloses, trip throughs and on/off times for short periods are not separately counted. The process is documented in a written procedure titled "Management of Forced Outage Information";
- planned circuit element outage times are taken EMS and logged individually for each circuit element's individual on/off times including any multiple interruptions (as may occur for work spanning two days).
- reports are produced in accordance with a documented "Procedure for Preparation of the ACCC Availability Report". A routine called the "ACCC Statistics Generation" matches events in FOD/OSTRAC with the EMS to a 5 minute tolerance. Exceptions are noted and corrected. The resulting data is transferred into an MS excel spreadsheet from which reports are generated.

Although the data collection and reporting system established by Powerlink relies on some manual input and manipulation of data, we have found the process to be robust. Historical data and future data collected using these processes should be suitable for use in a performance incentive scheme.

98 ACCC, 2005, *Final Decision: NSW and ACT Transmission Network Revenue Cap TransGrid 2004–05 to 2008–09*.

6.8 EXCLUSIONS FROM HISTORICAL DATA

Powerlink has provided historical data for the period 1996 to 2005 as shown in Table 6.3. We have relied on this data to assess the appropriateness of the targets for the performance measures. To ensure that the data is suitable for this purpose, we have compared the events that Powerlink has excluded from the data against the exclusion requirements of the SSG.

Powerlink provided extracts from its forced outage database and its planned outage database listing events that it has excluded from the historical data. The extracts show that Powerlink has excluded 137 events from its 2003, 2004 and 2005 historical data for the circuit availability and average outage duration measures and 100 events from the frequency of off-supply events measure. All of these exclusions have been made in accordance with the SSG.[99] The majority of the exclusions have been made on the basis that no Powerlink asset was affected (the historical data in 2003, 2004 and 2005 includes all assets for which Powerlink has operational responsibility including those assets owned by distributors). Powerlink advised that it has not excluded any events under the force majeure provisions of the SSG except for incidents caused by generators and customers as "acts and omissions of a party…which party is connected to or uses the high voltage grid etc."[100]

Powerlink has been developing its data recording systems since the issue of the SSG in 2003. In 2002, Powerlink did not separately record exclusions and we have been unable to determine whether appropriate exclusions have been made in this year. Prior to 2002, no exclusions were made.

We also examined events that were included in the historical data, such as the three largest events in the circuit availability and average outage duration measures and all events included in the frequency of off-supply events measure. We found that all of the events have been properly included.

We note that Powerlink included all events caused by lightning and storm activity. However, events caused by lightning and storm activity may be excluded from Powerlink's annual performance report under the force majeure provisions if sufficiently severe. The ACCC stated in its Decision on the SSG that only in exceptional circumstances will an event be excluded from the performance incentive scheme. This would leave most storm and lightning events included in the performance incentive scheme, with only exceptional events eligible for exclusion. For events caused by lightning, we consider that appropriate precautions, such as installing an overhead earth wire above a line, must also have been taken before the event is able to be excluded from the performance incentive scheme under the force majeure provisions.

Powerlink has included in the frequency of off-supply events measure for 2003 an outage due to lightning that resulted in a loss of 0.45 system minutes. During a lightning storm, both Collinsville to Mackay tee Proserpine 132 kV feeders tripped causing a loss of supply to Proserpine substation. Given that both lines failed together and normal precautions against lightning (overhead earth wire and surge protection) were taken, we consider that this event meets the exclusion provisions as an exceptional event. Accordingly, the event should be excluded from 2003 historical data for the frequency of off-supply events exceeding 0.2 system minutes.

99 Ibid, schedule 1.

100 Ibid, schedule 2.

Table 6.3: Powerlink's Actual Reliability Performance 1996–2005

Measure	Proposed Target	Actual Performance										Average	
		1996/ 97	1997/ 98	1998/ 99	1999/ 00	2000/ 01	2001/ 02	2002	2003	2004	2005	96-05	02-05
Circuit Availability - Total (%)	-	99.35	99.15	99.28	98.84			98.86	98.68	99.06			
Circuit Availability - critical (%)	97.15					98.37	98.18	99.8	98.5	99.4	99.7		99.4
Circuit Availability - non-critical (%)	97.98					98.71	98.69	98.7	98.7	99.0	98.6		98.8
Circuit Availability - peak (%)	97.45					98.3	98.42	98.7	98.6	99.0	98.7		98.7
Loss of supply events > 0.2 system minutes[4]	4	2	4	2	3	6	4	9	8 (6)	4	3	4.6 (4.3)	
Loss of supply events > 1.0 system minutes	1	0	0	1	1	2	2	3	1	0	0	0.9	
Average Outage Duration (minutes)	800	970	2027	625	518	183	286	743	701	794	1517		939

Source: Powerlink
Notes: 1. Shading indicates that Powerlink has low confidence in the data.
2. Data from 2002 is on a calendar year basis in accordance with the Service Standards Guidelines.
3. Averages omit data for the 2001/02 year, effectively omitting July - December 2001 from the average.
4. Data in brackets has been adjusted to align with the exclusion requirements of the Service Standards Guidelines (refer section 6.8).

We also identified an event in 2003 that had been included in the historical data resulting in outages of circuit elements not owned by Powerlink. Powerlink included this event as an inadvertent operation of its protection scheme initiated the incident that resulted in the loss of supply to distributor owned assets at Gympie. However, in our view, the event should be excluded from Powerlink's service standard measures because no Powerlink circuit elements were affected.[101] Accordingly, the event should be excluded from 2003 historical data for the frequency of off-supply events exceeding 0.2 system minutes making the number 6 rather than 8 events. See Table 6.3.

Table 6.3 shows in brackets the adjustments that have been made to the historical data to accord with the SSG exclusion requirements. We have relied on this adjusted data to assess the appropriateness of targets for the service performance measures.

6.9 TARGETS

Table 6.3 shows Powerlink's actual performance for the proposed performance measures over the period 1996-2005 and compares this performance with its proposed targets. When adjusted for the SSG exclusion requirements and compared to the targets recommended by SKM, Powerlink has, on average, outperformed its availability measures and underperformed against its frequency of off-supply events and average outage duration measures.

Table 6.4: Potential Change in Revenue 2002-05

Measure	Revenue Change (%)				
	2002	2003	2004	2005	2002-05 (average)
Circuit Availability – critical	0.16	0.16	0.16	0.16	0.16
Circuit Availability - non-critical	0.09	0.09	0.09	0.09	0.09
Circuit Availability – peak	0.16	0.16	0.16	0.16	0.16
Loss of supply events > 0.2 system minutes	-0.16	-0.16	0.00	0.00	-0.08
Loss of supply events > 1.0 system minutes	-0.30	0.00	0.30	0.30	0.08
Average outage duration	0.00	0.00	0.00	-0.15	-0.04
All indicators	**-0.06**	**0.24**	**0.70**	**0.55**	**0.36**

Source: PB Associates' analysis

Given this performance, if the targets proposed by SKM had been adopted in 2002, the net revenue difference in the period 2002-2005 would have resulted in an increase in allowable revenue of 0.36% over the four year period. Table 6.4 shows the change in each year would have been a 0.06% penalty for 2002, a 0.24% reward for 2003, a 0.7% reward for 2004 and a 0.55% reward for 2005.

This analysis indicates that Powerlink's proposed targets for the next regulatory period are unlikely to provide a revenue neutral outcome. We therefore consider that the targets should be adjusted to take account of the more recent performance data that has been collected since the SKM recommendations were made.

Powerlink has advised that its forward capex program does not provide for an improvement in the level of service that it provides to its customers. We have examined Powerlink's forward capital expenditure program and note that the projects are aimed at

[101] In this instance, the circuit breaker that tripped to cause the outage was owned by the DNSP and not by Powerlink.

maintaining, rather than improving, service delivery as the capacity of the network is expanded to meet the projected demand for electricity. Conversely, service standards should not fall. While a physically larger network will experience an increased number of faults, each performance measure is normalised by a factor representing the size of the network or is averaged. Accordingly, we accept Powerlink's statement in respect to future service levels and have made no adjustment to targets on this basis.

6.9.1 Circuit Availability Measures

Powerlink has collected historical performance data for each of the three circuit availability indicators since 2002. It also has a longer historical record of total circuit availability.

Given the small amount of data available for each of the three circuit availability indicators, we have examined the total circuit availability and determined that the performance since 2002 is representative of performance prior to 2002. We are therefore confident that the data collected since 2002 is sufficiently accurate overall for use in a performance incentive scheme.

Given that only four years of data is available, we propose that the average of the available data be used as the target for each measure. The alternative is to establish targets based on the trend of the historical data. The use of trends with such a small dataset is not likely to provide an accurate forecast of current performance and, therefore, has been rejected.

Powerlink claims that it has introduced initiatives aimed at improving its circuit availability performance over recent years. If this is the case, using the average of the recent historical performance will provide a conservative target, with some of the potential improvement not reflected in the target. We also note that Powerlink introduced RCM in 2002 but has yet to fully implement the program. While the introduction of a new approach to maintenance has the ability to impact on reliability performance, the historical data does not show a correlation. Total circuit availability was high in the period 1996 to 1999, and then reduced until 2004 when it returned to previous levels.

Powerlink states that the targets proposed by SKM for the circuit availability measures reflect the number of planned outages that were anticipated at the time to implement its large forward works program. It is not evident from SKM's report, however, that SKM was aware of Powerlink's forward capex program or made an appropriate allowance in its model for it. Powerlink has not provided any information to support its claims.

Because the circuit availability measures include planned outages due to the connection of "new" capital works, targets based on historical averages may need to be adjusted to allow for the proposed increase in capital works in the 2006-10 period. The period 2006-10 is used because Powerlink propose that the incentive scheme start from 1 July 2007, based on performance data from January 2006. In other revenue cap decisions, the AER has not commenced the performance incentive scheme until the regulatory control period has commenced. Consistent with this approach, the first revenue impact would occur from 1 July 2008 based on performance data reported for 1 July 2007 to 31 December 2007. This is different from Powerlink's Proposal.

Powerlink initially claimed that the typical total circuit unavailability of about 2.5% was made up of new works (1.3%), maintenance (0.7%) and forced outages (0.5%).[102] However, in subsequent discussions, Powerlink advised that this breakdown was indicative only and was not derived from an analysis of historical data. To obtain the proportions from historical data would require that each planned outage be classified as either new works or maintenance. Powerlink has not classified its outages in this manner.

[102] PowerPoint presentation, 15 May 2006

Given the large number of individual outages on Powerlink's network, Powerlink states that it would be time consuming to derive the required information from currently available records. Instead, to gauge the contribution of new works to the circuit availability measures, Powerlink examined typical projects that make up the future capex program. Based on outage planning for these projects, Powerlink developed an outage profile for four types of substation project and two types of lines project. This work, which was suggested by us and completed subsequent to the submission of Powerlink's Revenue Proposal, is summarised in Table 6.5 and Table 6.6.

Table 6.5 shows that the total estimated planned circuit outage hours per year is expected to rise from 70,295 per year in the 2002-04 period to 89,773 per year in the 2006-10 period.[103] Should the AER base the performance incentive scheme on data from 1 July 2007 to 30 December 2007, the planned circuit outages should be recalculated for the period 1 July 2007 to 30 June 2012. Table 6.6 shows that the total circuit unavailability for planned outages in 2006-10 will increase from 0.86 to an estimated 1.09% due to the increased volume of new works. Adding the average forced circuit outage hours per year (0.28%) gives a total circuit availability of 98.63%, a reduction of 0.24%.

Table 6.5: Estimate of Circuit Outage Hours due to Proposed Increase in New Works

Item		New works							Plan'd Maint. O'tage Hours per year	Total Plan'd O'tage Hours per year
		Substation Large	Substation Medium	Substation Small	Substation Transformer	Lines Large	Lines Small	Ave O'tage hours per year due to new works (A)	(B)	(A+B)
Estimated circuit outage hours per new project		13,120	3,989	660	4,831	5,512	686	-	-	-
2002-04	No of New projects	1	4	9	12	6	6	-	-	-
2002-04	Est. total circuit outage hours	13,120	15,956	5,940	57,972	33,072	4,116	43,392	26,903	70,295
2006-10	New projects	6	14	28	17	12	19	-	-	-
2006-10	Est. circuit outage hours	78,720	55,846	18,480	82,127	66,144	13,034	62,870	26,903	89,773

Source: Powerlink

103 The 2002-04 period is used because the 2005 reliability performance data was not available at the time.

Table 6.6: Estimate of Circuit Unavailability due to Proposed Increase in New Works

Item	Unit	Value
Circuit unavailability due to planned outages - average 2002-04 – (A)	%	0.86
Estimated circuit outage hours per year due to planned works - average 2002-04 – (B)	hours	70,295
Ratio (A/B*1,000,000) – (C)		0.12
Estimated circuit outage hours per year due to planned works - 2006-10 – (D)	hours	89,773
Estimated circuit unavailability due to planned outages 2006-10 (C*D/1,000,000) – (E)	%	1.09
Circuit unavailability due to unplanned outages – average 2002-04 – (F)	%	0.28
Estimated total circuit unavailability – (E+F)	%	1.37

Source: Powerlink

The model makes assumptions about the average circuit outage durations for typical projects and average maintenance hours per annum but is not sensitive to changes in these assumptions. PB Associates, therefore, considers that the model is robust and appropriately informs the setting of targets.

In setting appropriate targets the change in total circuit availability has been equally apportioned across the critical and non-critical sub-measures, that is, the full 0.24% has been applied to both measures. For the peak sub-measure, Powerlink proposes that the target should also be adjusted by the full 0.24% on the basis that a majority of new works will occur during peak periods: 7 am to 10 pm weekdays. This is because the maximum use of off-peak periods for planned works is already being made. We consider that these apportionments appear reasonable.

In addition, Powerlink proposes that the target for the circuit availability - peak sub-measure be further adjusted to reflect an increased amount of new asset connections that Powerlink expects to carry out in peak periods.

Powerlink states that all of the additional “cut ins” associated with its increased capital works program will be undertaken during peak periods. This is because Powerlink believes that it has exhausted opportunities to schedule any further works into off-peak periods, given current levels of overtime and safety issues that prevent significant works occurring during night-times. It proposes that the full 0.24% impact on overall circuit availability be applied to the peak availability measure. Multiplying 0.24% by the ratio of peak hours to total hours per year (3780/8760) gives an impact on circuit availability during peak periods of 0.56%. Hence, Powerlink has proposed a revised circuit availability target of 0.56% less than the average of performance since 2002.

We note that the assumption made by Powerlink that all of the additional “cut-ins” associated with its increased capital works program will be undertaken during peak periods does not take into account any change (increase) in workforce or synergy with its maintenance work program. It seems likely that Powerlink’s field labour or contractor resources will need to be expanded for Powerlink to deliver the proposed works program. We consider that an increased labour resource will provide scope for at least some of the “cut-in” works to be performed in off-peak periods.

Powerlink has indicated that it will need to increase its internal labour resource over the 5-year period by approximately 30% (from approximately 830 to 1080 employees). We consider that an increase in field labour resource availability during off-peak periods of 20% is not unreasonable. Hence, we believe that an increase in peak availability of 0.45% is appropriate.

Table 6.7: Recommended Targets and Weightings – Circuit Availability Indicator

Measure	Ave 2002-05 %	Allowance for new works %	Proposed Target %	Proposed Weighting %
Circuit Availability – critical	99.36	0.24	99.12	15.5
Circuit Availability - non-critical	98.76	0.24	98.52	8.5
Circuit Availability – peak	98.74	0.45	98.29	15.5

Source: PB Associates

We consider that adoption of the targets shown in Table 6.7 should ensure that the scheme is revenue neutral over the long term unless service standards decline or are improved.

6.9.2 Loss of supply event frequency index

Powerlink has high confidence in its historical data from 1996/97 to 2005 for the loss of supply events measures.

For the number of off-supply events greater than 1.0 system minutes, the data is consistent having an average of 0.9 and a range of 3. We recommend that the targets be set at the average of the long term performance, that is, 0.9 events.

The data for the frequency of off-supply events greater than 0.2 system minutes is not consistent, having an average of 4.3 and a range of 7. The historical data for this measure includes a single year of low performance, 2002. Without this year, the range reduces to 4. This indicates that the changed level of performance in 2002 may not be considered a natural variation. Nevertheless, given that reliable data is available from 1996, we recommend that the target is set considering all of the available data, including the 2002 performance, to better reflect Powerlink's long term performance. The average of the historical performance, shown in Table 6.3, is 4.3 events.

Conversely, Powerlink considers that all of the performance measures are linked and that the frequency of off-supply events measure should be based on the same average—the four years to 2005—as we have recommended for the other measures. We note that Powerlink's performance in this measure has been variable with the performance in 2002 being atypical. As a result, setting a target based on 2002-2005 data is unlikely to reflect the expected performance over the 2006-10 period. Given that Powerlink has high confidence in the data since 1996/97 we are not aware of any reason why the target should not be based on the long term data that is available.

Powerlink also considers that the frequency of off-supply events greater than 0.2 system minutes should be adjusted to allow for the proposed increase in new capital works in the 2006-10 period[104]. This adjustment is considered necessary since the capital works program will increase the number and impact of loss of supply events. As evidence, Powerlink indicate that six events that would not have occurred except that a circuit element was interrupted for 'new works' have exceeded the 0.2 system minutes threshold in the period 2002 to 2005. It proposes that the target for this measure should be based on the four year average with project related outage events adjusted for the relative outage duration hours expected in the 2006-10 period (an increase in this component of 44.9%). The target proposed by Powerlink is 7.75 events. Conversely, no events greater than 1.0 system minutes occurred due to the impact of new works and no change is proposed in this measure.

[104] E-mail to PB Associates dated 23 June 2006, *Impact of capital program on loss of supply targets.*

We consider that Powerlink's argument is not unreasonable. As an example, assuming a system maximum demand of about 7,900 MW and a line recall/repair time of 2 hours, an event interrupting a load of only 13 MW would exceed the 0.2 system minute threshold.

Table 6.8 shows the number of events that exceeded the 0.2 minute threshold that would not have occurred except that a circuit element was interrupted for 'new works'. It shows that, based on the Powerlink approach, an adjustment of 0.67 events per year would account for the proposed increase in new works for events greater than 0.2 system minutes.

Table 6.8: Adjustment to frequency of off-supply events greater than 0.2 system minutes measure due to increase in new works in 2006-10 period

No of events >0.2 system minutes due to:	2002	2003	2004	2005	Average 2002-05	Adjustment factor %	Increase due to increased new works
New works	1	2	2	1	1.50	44.9%	0.67
Other	8	6	2	2			
Total	9	8	4	3			

Source: PB Associates analysis

In its assessment, Powerlink has assumed a linear relationship between an increase in circuit exposure and its impact on the measure. This assessment does not take into account the relative size and location of projects in the past compared to the 2006-10 period. For instance, the majority of forecast projects are planned for the South East Queensland area which is already highly meshed. It also does not take into account the reduced reliance on the capacity of any one circuit element that will occur as the capital works program is rolled out. Offsetting this, the performance in 2004 and 2005 indicates that when the overall number of events exceeding the threshold is small, a greater proportion may be associated with outages for "new works".

PB Associates recommends that the target for the frequency of off-supply events greater than 0.2 system minutes be set at 5.0 events per year, which is 0.67 events above the average performance of the 1996/97 to 2005 period.

The average of the historical performance for the frequency of off-supply events exceeding 1.0 system minutes is not a whole number of events. A target based on this average would therefore result in Powerlink paying a penalty or receiving a bonus in any given year. In proposing this target, we have considered the following alternative approaches:

- Use average as target – while this approach leads to a revenue neutral outcome over the 5-year regulatory period for no underlying change in average performance, bonus and rewards each year can lead to an overall gain or loss due to the time value of money.
- Rounding of targets – rounding of targets to a whole number of events removes the need for adjustments in revenue if the target is met but leads to the scheme not being revenue neutral over the 5-year regulatory period.
- Dead-bands – dead-bands around the target would effectively move the trigger for a penalty or bonus to the next whole number of events, effectively smearing the target. This was the approach adopted by SKM in 2003.

In Powerlink's Revenue Proposal for the frequency of off-supply events exceeding 0.2 system minutes, a dead-band was included that effectively moved the target to the next whole number of events. Given that performance outcomes must be a whole number of events and that the number of events is in the same order as the targets, the application of a dead-band significantly reduces the sharpness of the measure and is not recommended.

For these reasons, we recommend that the targets for the frequency of off-supply events measures be set at the long term average without a dead-band.

Table 6.9: Recommended Targets and Weightings – Loss of Supply Events Measure

Measure	Unit	Proposed Target	Proposed Weighting %
Loss of supply events > 0.2 system minutes	No.	5.0	15.5
Loss of supply events > 1.0 system minutes	No.	0.9	30.0

Source: PB Associates

6.9.3 Average Outage Duration Measure

Historical data for the average outage duration measure is available from 1996/97. However, Powerlink has low confidence in the data prior to 2001/02. This is because the data was not collected in a consistent manner and appropriate exclusions were not able to be determined and omitted from the data.

Powerlink has collected data consistent with the measure definition provided in the SSG since 2002, although the data for 2002 is net of exclusions. Since 2003, exclusions have been left in the data set and flagged as excludable items so as to provide an audit trail.

Given the small amount of reliable data, we recommend that targets should be based on the average of the historical data since 2002. Table 6.3 shows that the average is 939 minutes.

The 2002 to 2005 period includes a single year of low performance (2005) in which the average duration was 1517 minutes. The large increase in the 2005 performance when compared to previous years is largely due to the inclusion of 10 events that reached the 7-day cap, indicating that a large variability may exist in this measure. This view is supported by the historical performance prior to 2002. While Powerlink has low confidence in the accuracy of this performance data, it shows a similar variability with one year of low performance in the 6 year period to 2001/02.

While the variability in this measure could be reduced by lowering the cap from 7-days to (say) 5-days, PB Associates is of the view that the 7-day cap is sufficiently low in value to limit the risk to Powerlink of single long events and that the average of four years performance with three years of good performance and one year of low performance is representative of likely performance in the 2006-10 period.

In Powerlink’s Revenue Proposal, a dead-band of 100 minutes was included between the target and the start of a bonus payment. Where rewards and penalties are symmetrical, we consider that dead-bands add uncertainty as to whether the scheme would be revenue neutral for no change in underlying performance. This is because they may negate a number of small rewards/penalties that might otherwise have offset a larger penalty/reward that falls outside of the dead-band. Conversely, dead-bands may assist a scheme to be revenue neutral when rewards and penalties are asymmetrical by removing small fluctuations about the average performance that attract unequal rewards and penalties.

For the average outage duration measure, we recommend symmetrical rewards and penalties without a dead-band.

Table 6.10: Recommended Targets and Weightings – Average Outage Duration Measure

Measure	Unit	Proposed Target	Proposed Weighting %
Average Outage Duration - capped 7 days	Minutes	939	15.0

Source: PB Associates

6.10 RAMPING FACTORS

For the performance incentive scheme to provide an appropriate incentive to Powerlink, the difference between the cap and collar values should be significantly wider than the natural fluctuation in the measure that might arise due to exogenous events. Otherwise, natural variations in performance could lead to significant revenue swings and/or the cap/collar values being exceeded. To avoid this effect the cap and collar values should ideally be about two standard deviations of the historical data, that is, if the natural variation is a normal distribution, one year in twenty would be expected to reach the cap or collar through natural variation. Use of a lesser standard deviation is not recommended, for instance, a standard deviation of 1.5 would lead to a probability of the cap/collar being reached approximately one in every seven years.

The use of standard deviations assumes that the distributions are normal, which is not possible to determine with such small datasets. Hence, a degree of caution needs to be exercised in using statistical methods to assist the setting of appropriate collars and caps.

Table 6.11 shows that the variation in historical data for the critical element availability measure is of the same order as the difference between the cap and collar values. This indicates that the collar and cap values should be widened so as to avoid annual performance reaching the cap or collar value through natural variation. As noted above the cap and collar values should ideally be set to two standard deviations of the historical data. However there is limited scope for improvement in this measure and a sustained improvement to the best level on record will be difficult to achieve. Therefore we recommend that the cap values for this measure be set at one standard deviation of the historical data while the collar value is set at 2 standard deviations. Table 6.11 shows the recommended collar and cap values.

Table 6.11 also shows that the variation in performance for the non-critical and peak circuit availability measures are more than three times less than the magnitude of the difference between the relevant cap and collar values. We therefore recommend that these cap and collar values be lowered to be two standard deviations of the historical data so that a change in performance places a reasonable amount of revenue at risk.

Table 6.11: Recommended Ramping Factors for Service Level Measures

Measure	Actual Performance		Powerlink's Proposal			Proposed Values		
	Range	Standard Deviation	Collar	Target	Cap	Collar	Target	Cap
Availability – Critical Elements	1.30	0.60	96.55	97.15	97.65	97.92	99.12	99.71
Availability - Non-critical Elements	0.37	0.17	96.33	97.98	98.33	98.19	98.52	98.85
Availability - Peak Hours	0.40	0.18	96.65	97.45	98.15	97.93	98.29	98.65
Loss of supply events > 0.2 system minutes	7	2.3	6	4	1	7.5	5.0	2.5
Loss of supply events > 1.0 system minutes	3	1.1	3	1	0	2.9	0.9	0
Average Outage Duration - capped 7 days	1,162	387	1,200	800	300	1,520	939	358

Source: PB Associates

Recent performance against the loss of supply events greater than 0.2 system minutes measure has a relatively wide range of 7, when compared to a target of 5.0, because of the large number of events exceeding the threshold in 2002. Adopting collars and caps at two standard deviations would give a range of more than 9. It seems unlikely that the performance in 2002 was due to natural variations in this measure. We consider that the adoption of collars and caps based on two standard deviations would not provide an appropriate incentive for this measure. Conversely, the range of 5 proposed by Powerlink appears reasonable and equates to approximately 1.5 standard deviations (omitting 2002). We therefore support the Powerlink proposed range of 5, giving a collar of 7.5 and a cap of 2.5 for the proposed target of 5.0 events.

For the loss of supply events greater than 1.0 system minutes measure, Powerlink has proposed collars and caps that equate to one event to gain the maximum bonus and two events to incur the maximum penalty. These equate to approximately one standard deviation on the reward side and two on the penalty side of the target or a maximum bonus given for zero events and a maximum penalty incurred for 3 events. These values appear reasonable, given that performance cannot be better than zero events.

For the average outage duration measure, the historical data contains 2 years of low performance and two years of high performance in 9.5 years. This variability indicates that the values of the collar and cap should be set at a standard deviation of at least 1.2 to ensure that the collar or cap values are not exceeded due to natural variations in performance. Powerlink's proposed ramping factor for the average outage duration measure results in a range of 900 minutes. This is close to the result obtained using a standard deviation of 1.2, which provides a range of 930 minutes. In contrast, a standard deviation of 2 would result in a range of 1549, which severely blunts the action of the measure, requiring a change in performance of almost 90% to reach the collar or cap.

PB Associates is of the view that the collar and cap values for the average outage duration measure should be set so as to balance the need to ensure that a change in performance places a reasonable amount of revenue at risk and the need to ensure natural variations remain uncapped and hence the scheme is revenue neutral for no underlying change in performance. Therefore, we recommend that the limits be set at 1.5 standard deviations providing a collar of 1520 and a cap of 358.

As noted in the previous section, the variability in this measure could be reduced by lowering the cap on the impact of any one event from 7-days to (say) 5-days. This would improve the sharpness of the measure; effectively placing a greater amount of revenue at risk for a given change in performance. We discussed this approach with Powerlink who confirmed that historical data was available to suit a revised cap. Insufficient time, however, was available to fully assess the viability of this option.

Table 6.11 shows our recommended collar and cap values.

6.11 SUMMARY

In summary, we recommend that six performance measures—as shown in Table 6.12—be included in Powerlink's performance incentive scheme.

Table 6.12: Recommended Performance Incentive Scheme

Measure	Unit	Weighting (%)	Max Penalty	Start Penalty	Target	Start Bonus	Max Bonus
Availability – critical elements	%	15.5	97.92	99.12	99.12	99.12	99.71
Availability - non-critical elements	%	8.5	98.19	98.52	98.52	98.52	98.85
Availability - peak hours	%	15.5	97.93	98.29	98.29	98.29	98.65
Loss of supply > 0.2 system minutes	Number	15.5	7.5	5.0	5.0	5.0	2.5
Loss of supply > 1.0 system minutes	Number	30	2.9	0.9	0.9	0.9	0
Average outage duration (capped 7 days)	Minutes	15	1,520	939	939	939	358

Source: PB Associates